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# Congestion management through topological corrections: A case study of Central Western Europe

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## HIGHLIGHTS

- We present the congestion management model in the CWE region.
- The benefits of topology control in the CWE region are quantified.
- Topology control significantly reduce congestion under the current market coupling.
- The benefits of topology control are limited under the nodal pricing regime.
- Network topology control is a promising option for mitigating congestion in Europe.

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## ABSTRACT

The integration of an increasing amount of renewable generation within Europe is posing operational challenges that require various balancing actions. System operators therefore need to rely increasingly on the active control of the transmission network. Transmission topology control is a fast and economical option to add flexibility to the transmission system. We model the current methodology for controlling congestion in the Central Western European (CWE) market and quantify the benefits of topology control. We also compare the results with a nodal pricing model. Our computational results suggest that topology control can significantly reduce congestion management costs under the current market coupling regime whereas the benefits of topology control are limited under nodal pricing. Topology control emerges as an attractive and implementable means of managing congestion as it provides a significant percentage of the cost savings that would be achieved by overhauling the existing European market design and shifting to a nodal pricing regime.



## 1. Introduction

The large-scale integration of renewable energy sources has been a long-standing target of European policy makers. This ambitious target has been reaffirmed by the recent directives of the European Commission (European Commission, 2009) as well as the 2050 Roadmap (European Commission, 2011). Renewable resources are commonly located far from load centers, and the renewable energy integration targets of European countries vary widely[1] relative to national energy demand, resulting in significant needs for cross-border power transfers and in congestion.

The impact of renewable energy integration on European transmission networks is exacerbated by the unpredictable fluctuation and variability of supply of these resources. This necessitates the deployment of conventional reserve capacity. However, the fuel emissions of standby generators and their thermal inefficiency in the range of standby operation undermine the environmental benefits of renewable supply integration. More importantly, the substantial investment cost in reserve capacity and the fixed cost of operating these units undermine the cost savings of renewable energy integration (Papavasiliou and Oren, 2013). Other balancing options include storage and the active participation of demand. Large-scale storage is economically prohibitive in most systems that cannot rely on pumped hydro storage (Sioshansi, 2011). Demand-side participation is progressing in Europe, however the technological and institutional reforms that are necessary for the large-scale deployment of demand response imply

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[1] The EU set mandatory national renewable energy targets ranging from 10% to 49% depending on countries for achieving a 20% of share of renewable energy in the final energy consumption (European Commission, 2009).

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that this option cannot be relied on in the immediate future.

Arguably, the active control of the transmission network could provide one of the most economically and institutionally acceptable technological means towards overcoming the operational challenges imposed by renewable energy integration. Transmission has commonly been treated as a passive resource in power system operations, and the physical laws that govern power flows have traditionally presented a range of challenges both in the operation and the market design of electricity systems. These challenges can be mitigated to a certain extent by an array of transmission control technologies. Investment cost is relatively low, and the active management of the network can result in an increased utilization of renewable supply.

Transmission control technologies include (i) flexible AC transmission (FACT) devices that alter the impedance of transmission lines, (ii) phase shifting transformers (PSTs) that enable the control of voltage angles along the ends of the line, (iii) high voltage DC (HVDC) lines that permit direct control of the amount of power flow over a line, (iv) tap changing transformers, (v) dynamic monitoring and adjustment of thermal line ratings, as well as (vi) topological corrections, namely the switching of lines in order to re-arrange flows in the network. The latter will be the focus of this paper.

The active control of the transmission network is especially relevant in the European context, due to the separation of the energy market from the operation of the transmission network. This separation introduces challenges in the coordination of production (including reserves) and transmission, and challenges in the coordination of resources that lie in different ends of national borders. The first challenge, separation of production from transmission, implies that the congestion faced by European transmission system operators (TSOs) may be substantial because the planning of generation in the day-ahead ignores the physical constraints that govern the flow of power over transmission lines. The second challenge implies that the most easily accessible option at the disposal of the system operator is the adjustment of production within the control area as well as the management of power flows through network control. The latter is arguably simpler since it does not necessitate the activation of resources in the balancing market and does not interfere with the outcome of the day-ahead market. This highlights the special relevance of transmission network control for European institutional arrangements: it can be performed locally, by a single entity (the system operator that is entrusted with the management of the transmission network) and results in minimal activation of balancing resources given the dispatch of producers and cross-border flows in the day-ahead market.

The problem of topological control, rather than topological corrections, for purposes of economic efficiency, has recently attracted the interest of the research community. Topological control within a technical-economic dispatch model was originally posed as a mixed integer linear program (MILP) by Fisher et al. (2008). The explosive evolution of computational capabilities has permitted detailed investigation of the problem in recent years, with applications on industrial scale networks and a demonstrated operating cost savings of 6% in the New York ISO system that includes 6652 lines, 689 generators and more than 4500 buses (Hedman et al., 2011a). Notwithstanding the potential economic benefits of actively integrating topology control in the economic optimization of the system, the problem presents formidable institutional and technological challenges. Computational time is daunting. The aforementioned result on the New York ISO was demonstrated after 82 h of computation, obviously a prohibitive requirement from an operational standpoint. Reliability is also a central concern of operators, although research results indicate that topological control can be integrated in the economic optimization of the system while being beneficial for the reliability of the network (Hedman et al., 2010). Transients on the network, resulting from switching, are also a concern for operators. Operators that utilize switching for corrective control conduct security and transient analysis of the impact of each proposed corrective switching action in the day-ahead time frame (Lambin, 2015). Although the incorporation of transient analysis in transmission switching[2] is an important subject with high practical interest for the widespread adoption of the technology, it is rather appropriate for a computationally oriented study rather than a policy-oriented study which attempts to quantify the potential benefits of transmission switching. In this respect, we will overlook questions of reliability and computational time in this paper in order to focus on the institutional integration of topology control in the economic optimization of the network, especially as it relates to the European market design.

From an efficiency standpoint, the active management of the network is linked inextricably to the day-ahead commitment of producers, both in order to satisfy forecast demand and for the purpose of providing reserves. Active network management can certainly deliver operating cost efficiencies reactively, in real time. Nevertheless, the benefits extend beyond reactive real-time corrections and the majority of such benefits may very well be proactive, namely in the efficient day-ahead scheduling (unit commitment) of production. The quantification of these benefits requires a centralized co-optimization model that departs vastly from current practice in European markets and is best approximated in practice by two-settlement systems based on nodal pricing. The comparison of the current market organization in Europe with a centralized market design is therefore largely hypothetical, since this market organization is de facto out of the question for Europe, at least in the immediate future. Nevertheless, the comparison remains interesting in its own right and raises challenges of modeling European power exchange operations, unit commitment, provision of reserves and congestion management that have not been adequately addressed in the literature. This is a gap that the present paper attempts to address.

The benefits of topology control, isolated from the day-ahead scheduling of production, have been considered in the context of wind power integration in Germany (Kunz, 2013). The author finds that topology control can benefit congestion management, although congestion management already represents a modest fraction of total system operating costs. Our paper aims to extend this analysis to the day-ahead time frame by (i) examining the interplay between active transmission network management and production scheduling through the clearing of power exchanges and the provision of reserves, (ii) analyzing the entire CWE region, with a higher fidelity model that includes 3188 nodes, 4085 lines and 1095 generators representing the region, and (iii) modeling transmission switching accurately, as a binary on-off decision.

In Section 2 we describe current operating practice in the Belgian system, which we use as a prototype model of the entire CWE region, and then proceed with a description of our model. Section 3 describes the data used in the case study. We present and discuss the results of our case study in Section 4. Section 5 concludes the paper with a discussion of policy implications.

[2] The terms topology control and transmission switching are used interchangeably.

## 2. Methods

### 2.1. Operations in practice

We will first describe the operations of the Belgian system operator, ELIA, and the market coupling model used in CWE, that includes the Belgian power exchange, Belpex. Since the 9th of November 2010, market coupling was launched in CWE, covering Belgium, the Netherlands, Luxembourg, France and Germany.

#### 2.1.1. Day-ahead market and unit commitment

The day-ahead power exchange is conducted as a double-sided uniform price auction. Participants can submit spot orders, and block orders. Spot orders are submitted as hourly increasing supply functions or decreasing demand functions. Block orders are meant to capture the non-convex unit commitment constraints associated with the operation of generators. Market clearing prices and cross-border trades are determined through the power exchange model, which is cast as a welfare maximization problem subject to complementarity constraints (Madani and Van Vyve, 2015). The power exchange uses a transportation model in order to represent the network, ignoring the physical constraints associated with Kirchhoff's laws. In this transportation model, the capacity of each cross-border link is determined by system operators, and referred to here as net transfer capacity (NTC).[3] The inefficiencies of European zonal market clearing have been discussed extensively in the literature (Ehrenmann and Smeers, 2005; Oggioni and Smeers, 2013).

Each supplier that injects power into the ELIA control area is required to inform ELIA about the status of its units, and the production schedule of each unit on a quarter-hourly basis. These schedules correspond to forward commitments including the commitments of generators in the day-ahead power exchange. Since power exchange bids are not associated to any specific unit, generators can optimize the commitment of their units subject to their power exchange obligations and reserve requirements after the day-ahead market has cleared.

#### 2.1.2. Real-time congestion management

Real-time congestion within the ELIA control area is managed as follows: (i) light overloads are acceptable for a short duration, (ii) topological modification of the grid can be performed in order to relieve short-term congestion, and (iii) tertiary control is activated on the longer term (ELIA, 2008b; Lambin, 2015). Re-dispatch resources are cleared in order to minimize congestion cost, with units stacked in increasing order for positive adjustments (payable from ELIA to producers), and decreasing order for negative adjustments (payable from producers to ELIA) (ELIA, 2014). Congestion management bids are paid as bid. In addition to using national re-dispatch resources in managing congestion, cross-border sharing of resources in real-time congestion management is possible. Presently, however, such coordination with TSOs in adjacent countries rarely takes place in Belgium as well as other European countries (Doorman and van der Veen, 2013; Lambin, 2015).

#### 2.1.3. Topological modification

ELIA resorts to topological modification as a corrective measure for congestion management. On the day-ahead stage, the system operator performs load flow calculations over the entire Belgian grid based on its load forecast and generation plan for the following day in order to check for transmission line overloads on an hourly basis. Topological modification and tap changes of transformers are corrective actions in the sense that they are determined in the day-ahead in response to potential line overloads that could occur in real time. These corrections are advisory for line overloads below 120% of the seasonal transmission line thermal rating, and mandatory for overloads exceeding 120% of the thermal rating. Topological corrections are implemented prior to the re-dispatch of generators because they cost less to the system operator and can be performed on very short notice.

In order to easily determine which transmission lines to switch, the system operator maintains a list of candidate lines that can be switched, which is determined mostly by experience and amounts to around 50 lines over the Belgian control area. This list can vary by season. Among all candidate lines, the system operator determines a subset of lines to be opened with the objective of eliminating congestion while respecting $N-1$ reliability. If there exist multiple solutions, the system operator chooses the solution that is relatively easier to implement in practice. The day-ahead remedial actions are communicated to dispatch engineers, who decide which corrective actions to apply 15 min in advance of real-time operations. Topological corrections can be activated within a few minutes through the automatic control system of ELIA.

Topological corrections are also implemented as a remedial measure at the CWE level. CORESO, the regional technical coordination service center that coordinates TSOs in CWE, receives an overview of each control area (production and load forecast as well as grid conditions) after day-ahead market clearing from the regional transmission system operator. Based on this information, CORESO proposes remedial actions to participating TSOs in response to any particular situations such as line outage, increase of international exchange, and high wind production on different time scales from the day ahead to real time. The remedial actions that CORESO resorts to include the topological modification of the grid as well as the modification of PST settings. System operators inform CORESO about their day-ahead topological correction plans, based on which CORESO analyzes the security on the entire CWE grid. Concrete examples of topological modification are provided in the CORESO operational reviews (CORESO, 2011).

As far as we are aware, the implementation of topological control by means of optimization is not currently applied in Europe. Instead, it is performed based on experience and as a corrective rather than proactive action. Nevertheless, the optimization of topological control within a mathematical programming framework model is receiving increasing attention from researchers as well as practitioners (Umbrella Project, 2013).

### 2.2. Model formulation

Having covered the relevant aspects of operation, in this section we relate these procedures to our model. We commence by introducing the modules of the market coupling system that currently dictates the operation of the CWE region. Fig. 1 illustrates the three different modules that compose the market coupling model, ranging from the day-ahead power exchange to real-time congestion management. In the day-ahead stage, the *power exchange module* clears energy and cross-border transfers over the entire CWE region for the following day on the basis of a zonal representation of the grid. Based on the power exchange results, each control area optimizes unit commitment and reserve requirements in the *unit commitment and reserve module*. This approximates the internal optimization performed by producers who are cleared in the power exchange and are required to meet their obligations using their generation portfolio. Following the commitment of thermal units, the TSO of each control area solves the

[3] Net Transfer Capacity (NTC) should be distinguished from Available Transmission Capacity (ATC). NTC refers to the transfer capacity that can be allocated for commercial transactions between zones, without violating security requirements. On the other hand, ATC represents the amount of transfers that remains available after forward transactions have been account for. In this paper, we simply refer to the available transfer amount between zones as NTC.

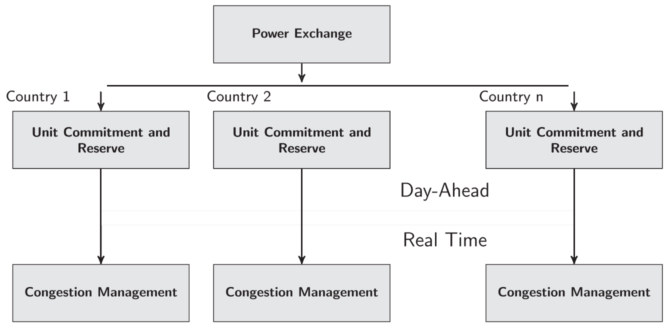


**Fig. 1.** Modules of market coupling model.

*congestion management module* in real time in order to relieve internal congestion caused by physical network constraints. At this stage, we only allow domestic re-dispatch in each control area in view of the current practice. Finally, we present the *nodal pricing model*, which, although it is not implemented in Europe, deserves attention as an ideal benchmark of coordination and economic efficiency. Fig. 2 provides the notation used in the formulations.

#### 2.2.1. Day-ahead power exchange model

We model the power exchange as a welfare maximization problem under the assumption of perfect competition and perfectly inelastic demand, where the transmission network is represented using a transportation model. Block orders are represented through binary variables, while detailed unit commitment constraints are accounted for in the co-optimization of reserves and unit commitment in Section 2.2.2 by introducing reserve requirements. The key output of the power exchange model is the day-ahead schedule of cross-border trades, which we fix in the congestion management model of Section 2.2.3. The power exchange model can then be formulated as follows:

$$\min \sum_g \sum_t C_g p_{gt} \tag{1}$$

$$\sum_{k \in \delta_n^-} f_{kt} - \sum_{k \in \delta_n^+} f_{kt} + \sum_{g \in g_n} p_{gt} + r_{nt} = D_{nt}, \quad \forall\, n, t, \tag{2}$$

$$0 \le r_{nt} \le R_{nt}, \quad \forall\, n, t, \tag{3}$$

$$P_g^- w_{gt} \le p_{gt} \le P_g^+ w_{gt}, \quad \forall\, g, t, \tag{4}$$

*Sets and indices*

$g$, $k$, $n$, $c$: generator, transmission line, bus, country,
$t$: hour (from 1 to $T$),
$g_n$: set of generators at node $n$,
$g_c$: set of generators in country $c$,
$\delta_n^+, \delta_n^-$: set of incoming and outgoing lines at node $n$,
$k_*$: set of transmission lines connecting two different countries,
$k_{c,cc}$: set of transmission lines connecting country $c$ to country $cc$,
$g_{on}$ : set of generators determined to be online at the day-ahead stage,
$g_f$ : set of fast generators that can start up in real time,

*Parameters*

$C_g$, $K_g$, $S_g$: marginal cost, minimum loading cost, startup cost of generator $g$,
$P_g^-$, $P_g^+$: minimum and maximum generation capacity of generator $g$,
$UR_g$, $DR_g$: maximum ramp up/down rates of generator $g$,
$UT_g$, $DT_g$: minimum up and down time of generator $g$,
$TC_k$: maximum flow capacity on line $k$,
$B_k$: susceptance of line $k$,
$M_k$: big-M values for line $k$,
$D_{nt}$: load at bus $n$ in hour $t$,
$R_{nt}$: renewable power available at bus $n$ in hour $t$,
$RS_{t,c}$: total contingency reserve requirement in hour $t$ in country $c$,
$NTC_{c,cc}$: net transfer capacity between countries $c$ and $cc$,
$\hat{f}_{kt}$: cross-border transfer determined in the power exchange,
$\hat{p}_{gt}$, $\hat{rs}_{gt}$: generation and contingency reserves determined at the day-ahead stage,

*Decision variables*

$w_{gt}$: decision to accept or reject block order of generator $g$ in hour $t$,
$u_{gt}$, $v_{gt}$, $p_{gt}$: commitment, startup, and production of generator $g$ in hour $t$,
$r_{nt}$: renewable power produced at bus $n$ in hour $t$,
$rs_{gt}$: contingency reserve provided by generator $g$ in hour $t$,
$z_{kt}$: decision to switch line $k$ in hour $t$,
$f_{kt}$: power flow on line $k$ in hour $t$,
$\theta_{nt}$: phase angle of bus $n$ in hour $t$,
$p_{gt}^+$, $p_{gt}^-$ : generation adjustments of generator $g$ at hour $t$.

**Fig. 2.** Nomenclature.

$$p_{gt} - p_{g,t-1} \le UR_g, \quad \forall\, g,\, t, \tag{5}$$

$$p_{g,t-1} - p_{gt} \le DR_g, \quad \forall\, g,\, t, \tag{6}$$

$$\sum_{k \in k_{c,cc}} f_{kt} \le NTC_{c,cc}, \quad \forall\, c,\, cc,\, t,\, w_{gt} \in \{0, 1\}, \quad \forall\, g,\, t. \tag{7}$$

The day-ahead power exchange minimizes the total generation costs (1) over the 24 h of the following day. Since we assume that the load is inelastic, minimizing total generation cost is equivalent to maximizing total welfare. The market clearing constraints (2) ensure the balance of demand, conventional production, renewable production, and zonal injections or withdrawals. Constraints (3) enforce maximum limits on the renewable power that can be generated at each bus. We allow spillage of renewable energy, although this assumption can be easily relaxed in order to represent must-take renewable supply. Constraints (4) impose minimum and maximum conventional generation capacity limits while constraints (5) and (6) enforce minimum and maximum ramping rates. We introduce a binary variable $w_{gt}$ in order to account for block orders that can only be fully accepted ($w_{gt} = 1$) or fully rejected ($w_{gt} = 0$). As the power exchange ignores congestion within countries, our model does not include constraints on intrazonal flows. However, transfers between adjacent countries are restricted by the net transfer capacity (7).

### 2.2.2. Day-ahead unit commitment and reserve model

The following model captures the firm-level optimization of unit commitment schedules against day-ahead power exchange obligations and the provision of reserves. In this model, we focus on contingency reserves that can be used to maintain a balance of power supply and demand in case of system contingencies (e.g. generator and transmission line outages). The contingency reserve requirements in this model represent the aggregate reserve capacity required. The global optimization of unit commitment against aggregate reserve requirements is meant to represent the collective behavior of producers that trade their commitments in the intraday market in order to arrive at a cost-optimal schedule that covers their obligations. The problem is solved by country, meaning that reserves are optimized separately within each control area, without coordination of cross-border reserve capacity. With this assumption at hand, the reserve and unit commitment problem can be developed as follows:

$$\min \sum_{g} \sum_{t} (C_g p_{gt} + K_g u_{gt} + S_g v_{gt}) \tag{8}$$

$$\sum_{k \in \delta_n^-} f_{kt} - \sum_{k \in \delta_n^+} f_{kt} + \sum_{g \in g_n} p_{gt} + r_{nt} + \sum_{k \in \delta_n^- \cap k_*} \hat{f}_{kt} - \sum_{k \in \delta_n^+ \cap k_*} \hat{f}_{kt} = D_{nt}, \quad \forall\, n,\, t, \tag{9}$$

$$0 \le r_{nt} \le R_{nt}, \quad \forall\, n,\, t, \tag{10}$$

$$p_{gt} \ge P_g^- u_{gt}, \quad \forall\, g,\, t, \tag{11}$$

$$p_{gt} + rs_{gt} \le P_g^+ u_{gt}, \quad \forall\, g,\, t, \tag{12}$$

$$p_{gt} - p_{g,t-1} + rs_{gt} \le UR_g, \quad \forall\, g,\, t, \tag{13}$$

$$p_{g,t-1} - p_{gt} \le \mathrm{DR}_g, \quad \forall\, g,\, t, \tag{14}$$

$$\sum_{g \in g_c} rs_{gt} \ge RS_{t,c}, \quad \forall\, t,\, c, \tag{15}$$

$$\sum_{q=t-UT_g+1}^{t} v_{gq} \le u_{gt}, \quad \forall\, g,\, t \ge UT_g, \tag{16}$$

$$\sum_{q=t+1}^{t+DT_g} v_{gq} \le 1 - u_{gt}, \quad \forall\, g,\, t \le |T| - DT_g, \tag{17}$$

$$v_{gt} \ge u_{gt} - u_{g,t-1}, \quad \forall\, g,\, t,\, v_{gt},\, rs_{gt} \ge 0, \quad \forall\, g,\, t,\, u_{gt} \in \{0, 1\}, \quad \forall\, g,\, t. \tag{18}$$

The objective (8) is to minimize total costs, which are defined by the sum of generation costs, minimum load costs and startup costs over a horizon of 24 h. Note that cross-border power transfers ($\hat{f}_{kt}$) determined in the power exchange model are respected in the energy balance constraints (9). Constraints on the amount of conventional generation (11)–(14) are equivalent to constraints (4)–(6) in the power exchange model, except that variables for reserves ($rs_{gt}$) are introduced in constraints (12) and (13). A minimum requirement on total contingency reserve at each hour and for each country is imposed by constraints (15). Minimum up and down time constraints of generators are enforced by constraints (16) and (17), and constraints (18) represent the logical relation between unit commitment variables and start-up variables.

### 2.2.3. Congestion management model

In the real time, the system operator resolves internal congestion by either resorting to the re-dispatch of generators, or to topological corrections. In the case of re-dispatching, it is also allowed to start new generators that were determined to be offline at the day-ahead stage but can be brought online in short notice, in real time. We assume that gas and oil units are classified as fast generators that can serve as backup capacity in real time, whereas nuclear, coal and lignite units are classified as slow generators. However, we assume that it is not allowed to shut down generators that were determined to be online at the day-ahead stage.

We assume that upward and downward adjustments are bid at the marginal production cost. Increase in production is paid according to the bid marginal cost. Decrease in production is paid for to the TSO. There exists ample empirical and theoretical evidence that pay-as-bid auctions do not induce truthful bidding, even under assumptions of perfect competition (Dijk and Willems, 2011; Holmberg and Lazarczyk, 2015), which has resulted in a careful monitoring of gaming in the re-dispatch phase. We therefore assume that the market is closely regulated in order to prevent gaming between the power exchange and re-dispatching. Our assumption is in line with existing rules in Belgian re-dispatch, whereby increase and decrease bids that are submitted up to the day-ahead time frame are determined by a formula that takes into consideration the fuel price and characteristics of the unit (ELIA, 2008a).

Since we assume that only domestic re-dispatch is allowed, the day-ahead cross-border flows are respected and hence are fixed in the model. Note that generation and reserve quantities determined at the day-ahead stage are denoted by hats. The congestion management problem can then be formulated as follows:

$$\min \sum_{g} \sum_{t} C_g (p_{gt}^+ - p_{gt}^-) + \sum_{g \in g_f} \sum_{t} (K_g u_{gt} + S_g v_{gt}) \tag{19}$$

$$p_{gt} = \hat{p}_{gt} + p_{gt}^+ - p_{gt}^-, \quad \forall\, g,\, t, \tag{20}$$

$$\sum_{k\in\delta_n^-} f_{kt} - \sum_{k\in\delta_n^+} f_{kt} + \sum_{g\in g_n} p_{gt} + r_{nt} + \sum_{k\in\delta_n^-\cap k_*} \hat{f}_{kt} - \sum_{k\in\delta_n^+\cap k_*} \hat{f}_{kt} = D_{nt}, \quad \forall\, n,\, t, \tag{21}$$

$$0 \le r_{nt} \le R_{nt}, \quad \forall\, n,\, t, \tag{22}$$

$$p_{gt} \ge P_g^-, \quad \forall\, g \in g_{on},\, t, \tag{23}$$

$$p_{gt} \le P_g^+ - \hat{rs}_{gt}, \quad \forall\, g_{on},\, t, \tag{24}$$

$$p_{gt} - p_{g,t-1} \le UR_g - \hat{rs}_{gt}, \quad \forall\, g_{on},\, t, \tag{25}$$

$$p_{g,t-1} - p_{gt} \le DR_g, \quad \forall\, g_{on},\, t, \tag{26}$$

$$P_g^- u_{gt} \le p_{gt} \le P_g^+ u_{gt}, \quad \forall\, g \in g_f,\, t, \tag{27}$$

$$p_{gt} - p_{g,t-1} \le UR_g, \quad \forall\, g \in g_f,\, t, \tag{28}$$

$$p_{g,t-1} - p_{gt} \le DR_g, \quad \forall\, g \in g_f,\, t, \tag{29}$$

$$\sum_{q=t-UT_g+1}^{t} v_{gq} \le u_{gt}, \quad \forall\, g \in g_f,\, t \ge UT_g, \tag{30}$$

$$\sum_{q=t+1}^{t+DT_g} v_{gq} \le 1 - u_{gt}, \quad \forall\, g \in g_f,\, t \le |T| - DT_g, \tag{31}$$

$$v_{gt} \ge u_{gt} - u_{g,t-1}, \quad \forall\, g \in g_f,\, t, \tag{32}$$

$$f_{kt} - B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0, \quad \forall\, k = (m, n),\, t, \tag{33}$$

$$-f_{kt} + B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0, \quad \forall\, k = (m, n),\, t, \tag{34}$$

$$-TC_k z_{kt} \le f_{kt} \le TC_k z_{kt}, \quad \forall\, k,\, t,\, v_{gt}, \ge 0, \quad \forall\, g \in g_f,\, t,\, u_{gt} \in \{0, 1\}, \quad \forall\, g \in g_f,\, t,\, z_{kt} \in \{0, 1\}, \quad \forall\, k,\, t. \tag{35}$$

The congestion management problem minimizes the total re-dispatching costs (19), which are defined by the sum of production adjustment costs of all generators, and minimum load costs and startup costs of fast generators that are brought online. Constraints (20) define total production as the sum of day-ahead production and real-time adjustments. Constraints on generators determined to be online at the day-ahead stage are enforced in (23)–(26), while constraints on fast generators that start in real time are provided in (27)–(32). As the model accounts for congestion caused by physical network constraints, flows are governed by the full set of network constraints. Moreover, topological corrections are considered in order to effectively manage congestion and are hence represented in the model using the MILP formulation of Fisher et al. (2008). A binary variable $z_{kt}$ is defined for each line, that represents whether a line is in service ($z_{kt} = 1$) or not ($z_{kt} = 0$). Constraints (33) and (34) represent Kirchhoff's power flow equations, whereby power flow equals the product of the susceptance $B_k$ of line $k$ and the phase angle difference between the two end buses of the line only when a line $k$ is in service. Note that introduction of big-$M$ values ($M_k$) is necessary in order to impose logical relations between line status and Kirchhoff's power flow equations. Power flow limits along each line that is in service are imposed through constraints (35).

#### 2.2.4. Nodal pricing model

We compare the decentralized market clearing design to an integrated optimization of day-ahead commitment, reserve commitment and topology control under physical network restrictions. The model that we solve is the following:

$$\min \sum_g \sum_t (C_g p_{gt} + K_g u_{gt} + S_g v_{gt}) \tag{36}$$

$$\sum_{k\in\delta_n^-} f_{kt} - \sum_{k\in\delta_n^+} f_{kt} + \sum_{g\in g_n} p_{gt} + r_{nt} = D_{nt}, \quad \forall\, n,\, t, \tag{37}$$

$$0 \le r_{nt} \le R_{nt}, \quad \forall\, n,\, t, \tag{38}$$

$$p_{gt} \ge P_g^- u_{gt}, \quad \forall\, g,\, t, \tag{39}$$

$$p_{gt} + rs_{gt} \le P_g^+ u_{gt}, \quad \forall\, g,\, t, \tag{40}$$

$$p_{gt} - p_{g,t-1} + rs_{gt} \le UR_g, \quad \forall\, g,\, t \tag{41}$$

$$p_{g,t-1} - p_{gt} \le DR_g, \quad \forall\, g,\, t, \tag{42}$$

$$\sum_{g\in g_c} rs_{gt} \ge RS_{t,c}, \quad \forall\, t,\, c \tag{43}$$

$$\sum_{q=t-UT_g+1}^{t} v_{gq} \le u_{gt}, \quad \forall\, g,\, t \ge UT_g, \tag{44}$$

$$\sum_{q=t+1}^{t+DT_g} v_{gq} \le 1 - u_{gt}, \quad \forall\, g,\, t \le |T| - DT_g, \tag{45}$$

$$v_{gt} \ge u_{gt} - u_{g,t-1}, \quad \forall\, g,\, t, \tag{46}$$

$$f_{kt} - B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0, \quad \forall\, k = (m, n),\, t, \tag{47}$$

$$-f_{kt} + B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0, \quad \forall\, k = (m, n),\, t, \tag{48}$$

$$-TC_k z_{kt} \le f_{kt} \le TC_k z_{kt}, \quad \forall\, k,\, t,\, v_{gt},\, rs_{gt} \ge 0, \quad \forall\, g,\, t,\, u_{gt} \in \{0, 1\}, \quad \forall\, g,\, t,\, z_{kt} \in \{0, 1\}, \quad \forall\, k,\, t. \tag{49}$$

The nodal pricing model minimizes total costs, which include generation costs, minimum load costs and startup costs (36), subject to nodal energy balance (37), renewable energy limits (38), constraints on unit commitment and reserves (39)–(46), and physical transmission network constraints (47)–(49). Note that transfers between adjacent countries are not restricted by NTCs in the nodal pricing model. The detailed information about the implementation of the models that were presented in this section as well as our experiment settings are presented in Appendix A.

## 3. Data

Our case study is conducted on a detailed representation of the CWE electricity market. All data used in our analysis is benchmarked against 2013 except the transmission network, for which the publicly available data is based on a projection for 2020.

### 3.1. Transmission network

We use the ENTSO-E System Study Model (STUM), which is a publicly available model that represents the power system of the

**Table 1**
Statistics for each country.

| Country | Code | #bus | #line | #generator | Capacity[a] |
|---|---|---|---|---|---|
| Belgium | BE | 81 | 152 | 21 | 15,002 |
| France | FR | 1,676 | 2,146 | 772 | 106,662 |
| Germany | DE | 1,296 | 1,603 | 302 | 65,699 |
| Luxembourg | LU | 20 | 18 | 5 | 1,367 |
| Netherlands | NL | 81 | 100 | 51 | 17,207 |

[a] Total generation capacity (MW).

ENTSO-E Regional Group Continental Europe synchronous area in 2020. We resort to the STUM as the most realistic network data available at the present time, despite the fact that it is based on a projection for 2020. The statistics of each country are summarized in Table 1.

The network model represents the 380 kV and 220 kV transmission grid and includes a full description of buses and transmission lines with physical transmission capacity and susceptance. This full grid information is used in the congestion management model and nodal pricing model. On the other hand, a simplified network with limited transfer capacity (NTC) between adjacent countries is used in the day-ahead power exchange model. Table 2 presents the sum of the physical capacities of the lines connecting each pair of countries in our model. Our analysis reports the results obtained with the actual day-ahead NTC values in 2013, which are derated relative to the sums of the thermal capacities in order to ensure the reliable operation of the system in real time. The day-ahead NTC values in 2013, which we obtained from the ENTSO-E transparency platform (ENTSO-E, 2015), are reported in Table 3.

### 3.2. Generation system

We divide generators into six types, according to fuel: nuclear, lignite, coal, gas, oil and hydro. Marginal generation costs are computed by taking into account the fuel price and CO2 emission cost, which are shown in Table 4, in line with the prices used in Abrell and Kunz (2013).

Since generator data obtained from ENTSO-E only provides generation capacity information and does not specify the fuel type of individual generators, we assign a fuel type to each generator in the database by taking into account the fuel generation mix of each country in 2013 (ENTSO-E, 2013b). Since the total capacity of units with a technical maximum at or above 100 MW accounts for more than 90% of the total generating capacity in the system, we simplify the representation of generators with a capacity below 100 MW by ignoring their unit commitment constraints and minimum generation levels. The number of generators and available generating capacities of each country are given in Table 1. Minimum load cost, startup cost, minimum up and down times and minimum and maximum ramp rate limits are generated according to fuel type, based on the data used in Papavasiliou and Oren (2013).

### 3.3. Renewable generation

We consider two sources of renewable supply, wind and solar power. Germany, France and the Netherlands are assumed to produce wind power, whereas solar power is only produced in Germany. The wind and solar power production output of the remaining countries was very low in 2013 (ENTSO-E, 2013b), and their production is therefore ignored. Renewable production in Germany is accounted for at the TSO level. The renewable production of each of the four German TSOs (50Hertz, Amprion, TenneT and TransnetBW) varies substantially due to their geographical distribution. For example, 50Hertz and Tennet produce much more wind power than Amprion and TransnetBW due to the fact that their control area mainly occupies the northern part of Germany (Fig. 3 presents hourly wind power production in 1 June 2013, by German TSO). The resulting hourly renewable production of each German TSO is assumed to be distributed evenly among the buses within its respective control area. Since we were only able to access wind and solar power production data at an hourly resolution for Germany, we apply the hourly wind production profile of Germany identically to France and the Netherlands while respecting their daily total production amount. The resulting hourly national renewable production is assumed to be distributed evenly among the buses of these countries.

**Table 2**
Interconnection capacity (MW).

| BE-FR | BE-NL | FR-DE | DE-NL |
|---|---|---|---|
| 4,511 | 7,100 | 5,130 | 4,480 |

**Table 3**
Day-ahead NTCs in 2013 (MW).

| BE-FR | BE-NL | FR-DE | DE-NL |
|---|---|---|---|
| 3,000 | 2,000 | 3,000 | 2,500 |

**Table 4**
Marginal generation costs (€/MWh).

| Nuclear | Lignite | Coal | Gas | Oil |
|---|---|---|---|---|
| 9.71 | 26.50 | 39.02 | 58.04 | 107.35 |

### 3.4. Scenario selection

In order to analyze the impact of different levels of load and renewable energy production, we choose four representative days in 2013 corresponding to a combination of high and low load, as well as high and low renewable supply, which results in 4 combinations. Hourly load and monthly renewable generation data of European countries can be obtained from the ENTSO-E database (ENTSO-E, 2013a). Table 5 shows the total amount of consumption and renewable energy production over 24 h for each of the four representative days that we choose. June 1 and October 5 are chosen as days during which load is relatively low, whereas

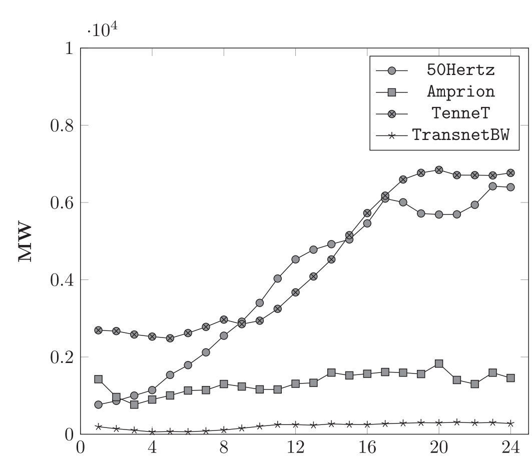


**Fig. 3.** Hourly wind power production on 1 June 2013, by German TSO.

**Table 5**
Total load and renewable generation of 4 representative days in 2013.

| | 06/01 | 10/05 | 11/29 | 12/10 |
|---|---|---|---|---|
| Total load (MWh) | 2,627,902 | 2,630,362 | 3,843,983 | 3,942,084 |
| Total renewable (MWh) | 399,497 | 108,898 | 434,564 | 95,395 |
| Renewable/load (%) | 15.2 | 4.1 | 11.3 | 2.4 |

November 29 and December 10 are days when the load level is relatively high. June 1 and November 29 correspond to high renewable generation and October 5 and December 10 correspond to low renewable generation. Thus, net load, represented by total load minus renewable generation, is lowest on June 1 and highest on December 10. Fig. 4 depicts the hourly variation of demand and renewable generation for each of the four representative days.

## 4. Results and discussion

We first present the results for the base case where topology control is not utilized for managing congestion in the CWE region. Therefore, only the re-dispatching of generators is considered in the congestion management model of the base case. In the nodal pricing model, all the transmission lines are assumed to be available in the base case. We then present the impacts of topology control by comparing the base case to the case where topology control is permitted for both the market coupling model and the nodal pricing model.

Our analysis of the market coupling model was carried out with two different levels of NTCs. NTC type 1 refers to the day-ahead NTC values in 2013, obtained from the ENTSO-E database. NTC type 2 refers to the sum of the thermal line capacities connecting two adjacent countries. The sum of type 2 NTCs over all interconnections is approximately 50% greater than the sum of type 1 NTCs. Both the nodal pricing model and NTC type 2 are hypothetical benchmarks in our paper. NTC type 2 cannot be implemented in practice due to the physical constraints of the network and reliability considerations, nevertheless we consider NTC type 2 in order to check the sensitivity of our results against the cross-border transfer capacity. Similar studies exist in the literature (CWE, 2013) that attempt to analyze the sensitivity of European electricity market cost and welfare to congestion. The meaning of the abbreviations that are used in the following tables and figures is summarized as follows:

- *MC*1: Market coupling model based on NTC type 1.
- *MC*1+*TC*: MC1 + topology control in real time.
- *MC*2: Market coupling model based on NTC type 2.
- *MC*2+*TC*: MC2 + topology control in real time.
- *NP*: Nodal pricing model.
- *NP*+*TC*: Nodal pricing model + topology control.

Table 6 illustrates the breakdown of costs for the base case and the cost savings achieved from topology control. Day-ahead cost refers to the total cost obtained from the unit commitment and reserve models while congestion management cost refers to the total costs obtained from the congestion management models.

### 4.1. Base case

Following the existing literature (Green, 2007; Leuthold et al., 2008; Van der Weijde and Hobbs, 2011), we first analyze the savings of the nodal pricing model, relative to the market coupling

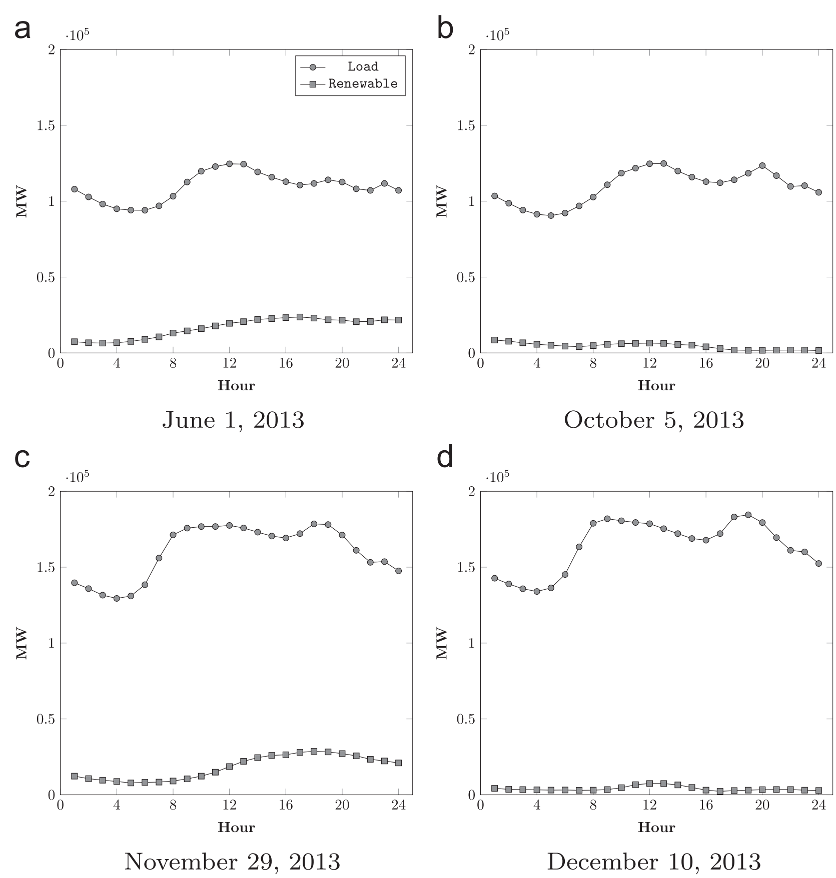


**Fig. 4.** Hourly load and renewable production of 4 representative days in 2013. (a) 1 June 2013, (b) 5 October 2013, (c) 29 November 2013 and (d) 10 December 2013.

model. The percentage cost savings that are achieved by nodal pricing relative to market coupling range between 2.84% and 6.15% compared to market coupling with NTC type 1, and between 1.45% and 4.48% compared to market coupling with NTC type 2. The cost savings are due to both the effective planning of day-ahead unit commitment and to operational efficiencies resulting from the coordination of cross-border power transfer. These daily savings translate to annual savings ranging between €0.4 and €0.5 billion, compared to the case where NTC type 2 is used in the market coupling model. Note that we assume that international re-dispatch is not performed in the congestion management phase, with TSOs having to rely instead exclusively on their zonal balancing resources. If international re-dispatch were permitted, the benefits of nodal pricing would have been more limited.

Under market coupling, congestion management costs caused by national network congestion are inevitable since the unit commitment schedule and the cross-border transfers determined in the day-ahead stage do not fully account for physical network constraints. Congestion management costs amount to 1.43–4.6% of the total cost in the case of NTC type 1 and 1.24–5.3% in the case of NTC type 2.

Market coupling with NTC type 1 results in higher total costs than NTC type 2. This stems from the fact that the type 1 NTC is smaller than the type 2 NTC for all cross-border interconnections, thereby restricting inter-country flows. However, congestion management costs are observed to be higher in case of NTC type 2, although total costs are lower. This can be explained by the fact that cross-border flows determined at the day-ahead stage, although enabling greater trade among countries, also tend to lead to greater violations of physical flows, which need to be alleviated in real time.

Table 7 provides an estimate of the average congestion management cost relative to total load. This cost ranges between 0.26 €/MWh and 0.69 €/MWh.. It is observed that congestion management becomes costly when the load is relatively low (scenarios 06/01 and 10/05) relative to scenarios with high load (scenarios 11/29 and 12/10). This can be explained as follows. Since the day-ahead model does not account for physical network constraints, the resulting unit commitment schedule closely tracks the national merit order. Consequently, when the load is low, mostly base-load generators are brought online in the day-ahead stage. However, in real time, due to transmission congestion, a considerable number of mid-merit power plants must be started, thereby resulting in costly congestion management. On the contrary, when the load is relatively high, most of the base-load and mid-merit generators are already committed in the day-ahead stage, enabling the operator to rely extensively on these online resources in order to resolve real-time congestion without starting too many new generators.

**Table 6**
Results of base case (1000 €) and cost savings achieved by topology control.

| Model | Cost | 06/01 | 10/05 | 11/29 | 12/10 |
|---|---|---|---|---|---|
| MC1 | Day-ahead | 32,940 | 44,573 | 63,359 | 81,484 |
| | Congestion management | 1,603 | 1,337 | 1,121 | 1,184 |
| | Total | 34,544 | 45,910 | 64,480 | 82,669 |
| MC1 + TC | Cost savings from TC | 1,219 | 1,162 | 895 | 1,113 |
| | % Cost savings | 76.0 | 86.9 | 79.8 | 94.0 |
| MC2 | Day-ahead | 32,136 | 43,899 | 62,519 | 80,488 |
| | Congestion management | 1,804 | 1,545 | 1,192 | 1,015 |
| | Total | 33,940 | 45,445 | 63,712 | 81,504 |
| MC2 + TC | Cost savings from TC | 1,400 | 1,380 | 911 | 556 |
| | % Cost savings | 77.6 | 89.3 | 76.4 | 54.7 |
| NP | Total | 32,417 | 44,093 | 62,606 | 80,315 |
| NP + TC | Cost savings from TC | 291 | 156 | 265 | 160 |

### 4.2. Benefits of topology control

As we have seen in the previous subsection, under market coupling the system operator has to re-dispatch units because the day-ahead market is cleared without accounting for internal transmission constraints, leading to increased balancing costs. Congestion can also be alleviated by the effective use of the existing transmission network. In particular, by switching out transmission lines, congestion caused by Kirchhoff's voltage law can be reduced. Topology control can also be adopted in the nodal pricing model, as we discuss in Section 3.4. In the nodal pricing model we co-optimize both unit commitment and transmission topology, therefore the optimization of transmission topology affects the unit commitment schedule and vice versa. Note that we allow at most two line switches at each hour and for each control area in the congestion management model and nodal pricing model (see Appendix A for details).

We first analyze the effectiveness of transmission topology control in mitigating inter-zonal congestion in real time. We observe from Table 6 that the daily savings achieved due to topology control are significant regardless of the NTC type and scenarios, and range between 54.7% and 94.0% of the congestion management cost of the base case. This translates to € 0.2–€ 0.5 billion of annual savings. These considerable savings are primarily due to shifting power production to lower marginal cost units by rearranging the topology of the network. In addition, the number of fast generators that are brought online in real time tends to decrease due to topology control. In Table 7 we present congestion management costs per MWh of demand. The fact that these cost savings are achieved by switching out at most a couple of transmission lines at each hour within each control area suggests that topology control is a minimally intrusive, implementable option, which is compatible with current practice in European markets.

The results suggest that topology control is less effective under nodal pricing than under market coupling. The cost savings that are observed in the nodal pricing model range between 0.19% and 0.89% of the total cost of the base case. This observation can be explained by the fact that the nodal pricing model optimizes unit commitment under a full set of internal transmission network constraints, therefore transmission restrictions are already reflected in the resulting unit commitment solution. Hence, the additional benefits of topology control are limited to operational efficiencies, compared to the market coupling model where benefits also stem from correcting for inefficient day-ahead scheduling.

### 4.3. Comparison of different models

Fig. 5 compares the total costs of the four scenarios, depending on market designs (market coupling or nodal pricing), NTC values (type 1 or type 2), and whether topology control is implemented or not. The $x$-axis represents the different model assumptions and

**Table 7**
Congestion management cost (€ /MWh).

| Model | 06/01 | 10/05 | 11/29 | 12/10 |
|---|---|---|---|---|
| MC1 | 0.61 | 0.51 | 0.29 | 0.30 |
| MC1 + TC | 0.15 | 0.07 | 0.06 | 0.02 |
| MC2 | 0.69 | 0.59 | 0.31 | 0.26 |
| MC2 + TC | 0.15 | 0.06 | 0.07 | 0.12 |

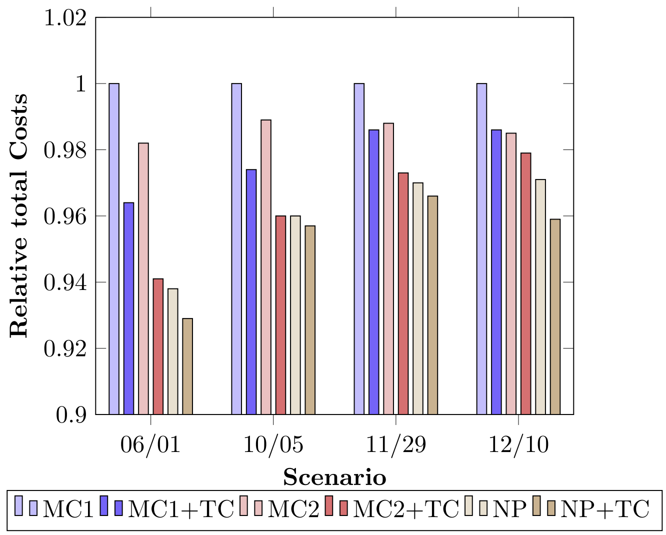


**Fig. 5.** Comparison of total costs for different model assumptions.

the $y$-axis represents the percentage of total costs compared to the total cost of MC1.

The cost savings due to the increase of NTC can be identified by comparing MC1 and MC2, which shows that increasing total NTC by 50% (MC1 to MC2) leads to a decrease of 1.01–1.74% in total costs. These savings result from increased international trade from cheap to expensive regions. The cost savings of topology control are identified by comparing MC1 with MC1+TC, and MC2 with MC2+TC. These savings range between 0.68% and 4.12% of total cost. The benefits stemming from nodal pricing can be identified by comparing MC2 and NP[4] and were already presented in Section 4.1. These savings range between 1.45 and 4.48% of total costs. The detailed percentage cost savings are summarized in Table 8.

An interesting finding of our analysis is the fact that topology control yields comparable benefits to those that could be achieved by adopting nodal pricing. Nodal pricing is encountering institutional objections in Europe. Instead, topology control is compatible with existing practices in electric power system and electricity market operations in Europe, with the TSO being ultimately responsible for this function. It comes as no surprise, then, that at least one European TSO already employs topology control as a balancing option in congestion management, albeit in an ad hoc fashion.

### 4.4. International transfers

We now compare the volume of international transfers. Table 9 presents daily total power transfer through the four cross-border transmission lines of the CWE region. We first note that increasing NTC values results in an increase of transfer volume, as expected. International transfers are also increased in the nodal pricing model, compared to MC1. However, when the load is relatively high (scenarios 11/29 and 12/10), we observe that international transfers resulting from the nodal pricing model are lower than those obtained from MC2. This is due to the fact that the nodal pricing model may restrict international transfers that result in heavy internal congestion in real time. The effect of topology control in the volume of international transfers is not entirely clear as the effect may be different for different levels of load. Specifically, when the load is low (06/01 and 10/05), topology control reduces international transfers and the reverse is observed when the load is high.

**Table 8**
Summary of the percentage cost savings achieved by different alternatives (%).

| Alternative | 06/01 | 10/05 | 11/29 | 12/10 |
|---|---|---|---|---|
| NTC increase | 1.74 | 1.01 | 1.19 | 1.40 |
| Topology control (MC1) | 3.52 | 2.53 | 1.38 | 1.34 |
| Topology control (MC2) | 4.12 | 3.03 | 1.42 | 0.68 |
| Nodal pricing | 4.48 | 2.97 | 1.73 | 1.45 |

### 4.5. Perspective on future research

$N-1$ reliability is a common security criterion that TSOs adhere to. The $N-1$ security criterion requires that the system be able to survive the failure of any single component, including generators, transmission lines, transformers and bus bars. Whereas it is computationally straightforward to check for $N-1$ security for a given state of the system, embedding $N-1$ security constraints in a decision making framework is computationally overwhelming, even for small-scale systems of purely academic interest. For example, Hedman et al. (2010) report that solving a co-optimization problem of unit commitment and transmission switching with $N-1$ constraints over 24 h required well over 20 h for the IEEE 73-Bus test system, even with advanced computational resources. Due to the fact that a policy study must analyze multiple scenarios (different seasons and loading conditions) of the same system in order to arrive to robust policy conclusions, thereby multiplying the required computational burden, policy-oriented literature including Kunz (2013) and Abrell and Kunz (2013) downgrade transmission capacity to approximate $N-1$ reliability requirements. In this study, we follow a similar approach of substituting an explicit enumeration of $N-1$ reliability constraints with contingency reserve requirements, as proxies for enforcing $N-1$ reliability by providing enough generation capacity to secure the system against contingencies. Whether reserve constraints are appropriate proxy constraints for $N-1$ reliability within a transmission switching model remains an open question (Hedman et al., 2010), nevertheless reserve constraints can increase the reliability of the system and have commonly been used in unit commitment models for the same reason (Papavasiliou et al., 2011; Liu and Tomsovic, 2012; Morales-España et al., 2013). Future research should concentrate on whether economic savings obtained from the incorporation of reserve constraints can directly be translated to those that could be obtained from the explicit enforcement of $N-1$ reliability constraints. This question has been addressed for IEEE test systems. In these systems, significant cost savings have been reported in the literature under $N-1$ constraints (Hedman et al., 2010; Khanabadi et al., 2013). Moreover, it is possible that switching can in fact improve reliability under certain system conditions (Hedman et al., 2011b). The investigation of whether such conclusions can be extended for larger scale systems such as the one studied in this paper is left as future work.

Our model does not capture the uncertainty of renewable power supply and load forecasts. An endogenous representation of uncertainty in an optimization and Monte Carlo simulation framework could influence our conclusions regarding topology control. Since topology control is a reactive control action that can be implemented very rapidly and close to real time, once the conditions of the system are known, we expect that the benefits reported in this paper understate the potential benefits that could be observed if forecasts errors were modeled explicitly. In this sense the current paper provides a conservative estimate of the value of topology control. This endeavor becomes especially relevant as

[4] We compare the cost of nodal pricing with the cost of market coupling based on NTC type 2 since both models admit the full rating of thermal capacity on inter-country lines.

**Table 9**
International transfer (MWh).

| Model | 06/01 | 10/05 | 11/29 | 12/10 |
|---|---|---|---|---|
| MC1 | 197,107 | 194,192 | 162,526 | 139,676 |
| MC2 | 288,980 | 263,350 | 218,718 | 166,297 |
| NP | 293,925 | 274,483 | 181,898 | 160,855 |
| NP+TC | 289,195 | 249,924 | 195,661 | 181,159 |

numerous European systems are rapidly increasing their reliance on wind and solar power, thereby increasing their exposure to the output of highly variable, unpredictable and non-controllable resources.

Lastly, our model suffers from shortcomings with respect to consideration of a detailed nodal distribution of renewable production as we assume that hourly renewable production of each TSO is distributed evenly among the buses within its respective control area. We expect that our model provides a lower bound on the potential savings achievable under the more realistic distribution of renewable production. This can be explained by the fact that congestion tends to increase with the uneven geographical distribution of renewable production, resulting in greater potential for topology control to provide higher savings.

## 5. Conclusion and policy implications

In this paper we have focused on quantifying the benefits of topology control in the operation of European electricity markets. We have modeled the sequential operation of the European power exchange followed by re-dispatch on an industrial scale representation of the CWE system (3188 buses, 4085 lines and 1095 generators). The sequential model accounts for (i) the clearing of the European power exchange, (ii) unit commitment in order to meet power exchange obligations and reserve requirements, and (iii) real-time congestion management performed by the system operator using both generator re-dispatch as well as topology correction. Our analysis has enabled us to quantify the relative performance of the existing European market design (market coupling followed by congestion management) with perfectly coordinated operations, and has also enabled us to quantify the benefits of active network topology control.

In order to analyze the congestion management costs resulting from the absence of physical network constraints in the day-ahead power exchange, we have compared the market coupling regime that is currently employed in the CWE market with nodal pricing, whereby energy, reserves and transmission are cleared simultaneously. The results indicate significant congestion management costs in real-time balancing, that range between 1.4% and 4.6% of total costs, depending on net load in the system. Our analysis indicates that the savings that can be achieved by nodal pricing range between 2.8% and 6.1% of total costs.

Our analysis proceeds with quantifying the potential benefits of topology control in the market coupling and nodal pricing regime. The results indicate that topology control in real-time congestion management reduces national congestion significantly, with savings ranging between 1.3% and 3.5% of total costs. The relative savings of topology control under nodal pricing are fewer, ranging between 0.1% and 0.8% of total costs. We can conclude that topology control is a more valuable technological alternative to managing congestion under the European market design. This fact coincides serendipitously with the alignment of topology control with European electricity market and power system operations, whereby the TSO is ultimately responsible for real-time congestion management through active network management. Moreover, the case study showed that topology control in real-time congestion management is capable of providing comparable cost savings to those that could be achieved by overhauling the existing CWE market design and adopting nodal pricing.

The policy implication of our study is that a more systematic consideration of topology control is in order. In light of the fact that the benefits of reactive topology control, which can be implemented under the existing European market design, can deliver comparable efficiency gains to that of nodal pricing, which is encountering insurmountable policy barriers in Europe, a more careful consideration of topology control is warranted. To the best of our knowledge, European system operators currently perform topological corrections on an ad hoc basis. The explicit representation of topology control in planning and dispatch software emerges as an opportunity which is compatible with existing market operations in Europe, within our technological reach, and has been shown in the present and other studies to hold substantial potential benefits. The increasing importance of implementing decision support systems for the active management of the transmission grid is further demonstrated by ongoing European research (Umbrella Project, 2013).

In this study, we have assumed that the transmission network is equipped with switching and communications equipment that is necessary for implementing topological corrections. This is largely true, at least in Belgium where 50 lines are currently available for switching. Note that since transmission switching technology already exists and has been used in the industry, there will be no need to develop new technologies, and thus investing in topology control boils down to installing existing technologies in the network and ensuring their proper maintenance. Moreover, the case study presented in this paper demonstrates that switching out at most a couple of transmission lines at each hour within each country is sufficient for achieve substantial cost savings. This suggests that the deployment of topological control does not require the installation of switching equipment in all transmission lines because only a subset of lines are likely to be switched quite often while some lines may never be switched. The limited investment costs that are required for deploying topological control further enforce our policy conclusion that its systematic consideration and widespread implementation is in order in the European electricity market.

In addition to topological control that we have investigated in this paper, an array of active transmission grid management technologies, including tap changing transformers, and FACTs devices, can provide a significant amount of flexibility and contribute to congestion management. These options are receiving serious consideration by European TSOs due to cost and short activation times, relative to re-dispatching. This is especially true as the congestion management budget of European TSOs is closely regulated by respective national regulatory authorities. In Belgium, ELIA is accountable for justifying its annual congestion management and balancing costs to the Belgian regulator (CREG) (Lambin, 2015). In Germany, the German regulator (BNetzA) enforces a mechanism whereby the TSO bears 25% of the additional cost above a certain threshold budget, or retains 25% of the cost savings (Nüßler, 2012). The flexible use of the transmission grid (in particular dynamic line rating (DLR), PST control and HVDC links) is especially relevant in facilitating a large penetration of wind and solar power over the European electricity system, as recent research demonstrates (Twenties Project, 2013). The Belgian TSO is especially interested in the deployment of DLR, whereby the transmission capacity of overhead lines is precisely monitored in real time and thereby can be higher than the seasonal rating, especially in days with more wind due to the higher cooling effect of the wind over the lines. This allows more power to flow through the lines (Schell et al., 2011), thereby minimizing curtailment of wind power and increasing the flexibility of the network. ELIA recently installed DLR devices on cross-border lines to augment the capacity of electricity import from France and the Netherlands (Lambin, 2015).

## Acknowledgment

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## Appendix A

This appendix provides implementation details regarding the models that were presented in Section 2.2. All of the models were solved using CPLEX 12.6.

The congestion management problem presented in Section 2.2.3 is a MILP that can be fed into state-of-the-art solvers. However, the problem remains computationally intractable for large-scale power systems. Therefore, the congestion management problem is solved in two steps by sequentially solving the commitment of fast units and topology control. First, the problem is solved with transmission switching variables fixed. We then fix the unit commitment variables ($u_{gt}$) of fast generators that are brought online in real time to their solution values and then the resulting problem is optimized for the topology control variables ($z_{kt}$). In order to avoid compromising the dynamic stability of the system, we restrict the number of transmission lines that can be switched out at each hour by enforcing the following constraint:

$$\sum_k (1 - z_{kt}) \le N, \quad \forall\, t,$$

where $N$ is the maximum number of line switches that are allowed at each hour. This constraint also reduces the computational difficulty of the problem without significantly deteriorating the quality of solution, as it is observed that the majority of cost savings can be achieved by switching a small number of lines (Fisher et al., 2008). In order to further speed up the solution time, notably for the French and German networks, we choose $N$ transmission lines one by one by repeatedly solving the problems with the constraint:

$$\sum_k (1 - z_{kt}) \le 1, \quad \forall\, t.$$

In our experiment, we assume that the allowed number of transmission line switches is at most two, for each hour and at each control area. Finally, we use the indicator constraints option of CPLEX for modeling the big-$M$ logical constraints (33) and (34). This option tends to be more robust numerically than a conventional big-$M$ constraint that does not involve reasonably small $M$ values.

The nodal pricing model presented in Section 2.2.4 is solved sequentially by iterating among the following three subproblems: a dispatching subproblem (Step 1), a unit commitment subproblem (Step 2) and a topology control subproblem (Step 3). A detailed description of the proposed decomposition approach follows:

Step 0. Set $i$:=0, $u_{gt}$:=1 for all $g$, $t$, and $z_{kt}$:=1 for all $k$, $t$.
Step 1. Solve the problem with $u_{gt}$ and $z_{kt}$ fixed and then fix cross-border flow variables to their solution values .
Step 2. For each country, solve the problem with $z_{kt}$ and the cross-border flows fixed, then fix $u_{gt}$ to their solution value.
Step 3. For each country, solve the problem with $u_{gt}$ and the cross-border flows fixed, and then fix $z_{kt}$ to their solution value.
Step 4. If $i = i_{max}$, terminate. Otherwise, increase $i$ by 1 and return to Step 1.

The total cost improves over iterations as each subproblem fixes certain variables to the solution values obtained from the previous step and optimizes for the rest of the variables. The total cost eventually converges to a value that serves as an upper bound on nodal pricing cost. In our experiment, we iterate our decomposition algorithm three times, since cost improvements become marginal beyond three iterations.

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