The Impacts of Transmission Topology Control on the European Electricity Network

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***Abstract*—The EU is targeting a 20% share of energy from renewable resources by 2020 and this increase is in turn expected to lead to operational challenges that will require various congestion management actions by system operators. In this paper, we deal with topology control of the transmission network as a congestion management resource and evaluate the impacts of topology control on the European electricity network. To do this, we co-optimize unit commitment and transmission switching over 24 hours and we use a decomposition scheme to tackle the resulting large-scale problem. Our analysis is conducted on different scenarios of load and renewable power generation. We find that topology control results in significant cost savings within Europe which tend to be inversely related to net load. The robustness of our results is supported by an extensive sensitivity analysis.**

***Index Terms*—Congestion management, renewable energy, transmission switching, topology control, unit commitment.**

I. Introduction

THE EU is facing an unprecedented period for energy policy as it is adopting ambitious energy and climate change objectives for 2020 towards a low-carbon future. These targets have been laid out in a series of policy directives released by the European Commission, including the Renewable Energy Directive (2009) [1], Roadmap 2050 (2011) [2], the Energy Efficiency Directive (2012) [3] and the Emissions Trading Scheme Directive (amended in 2013) [4]. The increase in the share of renewable energy production is a key element of European policy objectives. The Renewable Energy Directive [1] sets varying renewable integration targets in State members by 2020, ranging from 10% integration in Malta to 49% integration in Sweden.

The large-scale integration of renewable energy sources within Europe is expected to pose challenges in the operation of the electricity transmission network due to increased deviations from forecasts, congestion and cross-border flows. The diversity of renewable energy integration targets among states and the remote location of certain high-yield renewable sites far from load centers is expected to result in cross-border as well as internal congestion. For example, in Germany significant amounts of wind capacity are installed in the northern part of the country while load is mainly located in the mid-western and southern part of Germany. This is expected to result in an increasing flow of electricity from northern to southern Germany and hence will require significant investment in network extensions or lead to the increase of congestion management costs [5], both within Germany as well as in neighboring countries due to loop flows [6].

Congestion may be alleviated by increasing transmission capacity through transmission grid extensions. This option requires a significant commitment of capital, and optimal planning is influenced by long-term forecasts of electricity generation and load that are typically highly uncertain [7]–[9]. Although the need for investment in network extensions is increasing and has been accepted by policy-makers, investments are lagging during the past decade within Europe [10].

Given the difficulty in increasing transmission capacity, congestion can also be alleviated by making more effective use of the existing network. Market coupling in Europe is based on a zonal pricing model for the clearing of day-ahead exchanges, while congestion is managed within each country through re-dispatching [11], [12]. As real time approaches, the transmission network can be controlled actively in order to alleviate congestion and balance forecast deviations by using a variety of active network control technologies, including FACTS devices, phase shifters, tap changing transformers, HVDC line flow control, and the control of the topology of the network through the switching of transmission lines. We explore the latter option in this paper.

The active control of the transmission network through the aforementioned technologies, including transmission line switching, has been traditionally recognized as a measure for reacting to system contingencies and imbalances, rather than a proactive measure for economically operating the system [13], [14]. Transmission system operators, including the Belgian TSO ELIA, apply topological corrections on an ad hoc basis as the first line of defense for congestion management [15]. Owing to the rapid increase of computational capabilities, a systematic approach to topology control for minimizing the cost of power system operations has recently received the attention of the research community. Fisher et al. [16] first proposed a mixed integer linear programming formulation for co-optimizing generation dispatch and network topology, and showed that transmission switching reduced operating costs significantly on the IEEE 118 bus system. Prompted by this result, Hedman et al. [17], [18] subsequently analyzed the market impacts and reliability implications of transmission switching. In [19], the authors co-optimize unit commitment and transmission switching subject to N-1 reliability constraints on the RTS 96 system.

Subsequent work by Villumsen and Philpott [20] analyzes

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the impact of transmission switching on the optimal expansion of transmission networks. The authors apply their model in order to analyze the implications of transmission switching on the mitigation of wind power fluctuations in Denmark [21]. Similarly, Kunz [5] considers transmission switching as a congestion management method in Germany in order to integrate a high share of intermittent renewable power generation.

Despite the benefits of transmission switching on operating costs, the computational complexity of the problem remains a key impediment to its implementation in power system operations. Liu et al. [22] and Barrows et al. [23] propose a prescreening method to select a few switchable line candidates in order to reduce the number of binary variables in the problem. Ostrowski et al. [24] analyze symmetry resulting from identical transmission lines. Fuller et al. [25] and Ruiz et al. [26] propose heuristic line selection policies based on sensitivity analysis. In this paper we employ a decomposition approach similar to that proposed by Hedman et al. [19].

The consideration of the integrated European system is especially relevant in view of the envisioned coupling of the European energy market [27]. By employing an industrial scale model of the European system with detailed data on transmission, demand and renewable generation, we identify significant potential benefits of transmission topology control in reducing congestion management costs across Europe. A notable finding of this realistic large-scale analysis is that the benefits of topology control are accentuated under conditions of low net load, i.e., under conditions of high renewable energy production and low demand, due to the improved utilization of mid-merit units. This implies that transmission topology control becomes especially promising in view of the ambitious targets of renewable energy integration [1] and energy efficiency [2] in Europe, which are expected to reduce net load in the system.

The paper is organized as follows. Section II presents the formulation of the model and the decomposition approach is given in Section III. Section IV describes our dataset and the scenario definitions. The results of our numerical experiments are presented and discussed in Section V and our conclusions are summarized in Section VI.

II. Model Formulation

The European power system is based on a zonal decomposition, where regions are coordinated through the day-ahead power exchange and each zone is balanced by the local transmission system operator (TSO). The power exchange clears the day-ahead market based on a simplified transportation network representation of the transmission grid with available transmission capacities (ATC) between zones. The power exchange is followed by the day-ahead commitment of physical capacity and reserves in order to ensure the delivery of scheduled trades. In real time, TSOs relieve congestion while accounting for the physical constraints of the transmission network.

In keeping with the zonal organization of the European electricity market, we assume that each zone optimizes the control of its transmission topology independently. In particular, and as shown in Fig. 1, topology control takes place with power transfers between regions fixed to the values cleared in the day-ahead market and without further coordination between regions. Our motivation for this zonal decomposition is to adhere to a realistic modeling of topology control that is consistent with the existing organization of European electricity markets. Naturally, such a zonal decomposition incurs efficiency losses due to lack of coordination. The results reported in this paper, therefore, isolate the benefits of topology control from the benefits of inter-zonal coordination.

The following notation will be used in the paper.

Sets and indices

g, k, n, t, r: generator, line, bus, hour (1 to T), region,
$\delta^-(n)$, $\delta^+(n)$: Set of incoming and outgoing arcs at bus n,
g_n: Set of generators located at bus n,
g_r: Set of generators in region r,

Parameters

C_g, K_g, S_g: Marginal cost, minimum loading cost, startup cost of generator g,
V_n: Demand response valuation at bus n,
P_g^-, P_g^+: Minimum and maximum generation capacity of generator g,
R_g^-, R_g^+: Minimum and maximum ramp rate of generator g,
UT_g, DT_g: Minimum up and down time of generator g,
FR_g: Fast reserve limit 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,
$TR_{t,r}^{req}$, $SR_{t,r}^{req}$: Total reserve requirement and slow reserve requirement in hour t in region r,

Decision variables

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,
fr_{gt}, sr_{gt}: Fast and slow reserve provided by generator g in hour t,
l_{nt}: Demand response at bus n in hour t,
z_{kt}: Decision to switch line k in hour t,
f_{kt}: Power flow on line k in hour t,
θ_{nt}: Phase angle of bus n in hour t.

A. Inter-Zonal Power Flows

The dispatch model that we present in equations (1)-(5) approximates the operation of the day-ahead power exchange. This problem is solved once over the entire network in order to determine cross-border power transfers between zones. Using the notation defined above, the dispatch problem can be developed as follows.

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

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

$$-TC_k \le f_{kt} \le TC_k,\ \forall k,t, \tag{3}$$

$$0 \le r_{nt} \le R_{nt},\ \forall n,t, \tag{4}$$

$$P_g^- \le p_{gt} \le P_g^+,\ \forall g,t. \tag{5}$$

The dispatch problem minimizes total generation cost (1) subject to power balance constraints (2). Capacity limits on the flow of power over transmission lines (3), on renewable generation (4), and on power generation (5) are imposed. In keeping with European day-ahead power exchange market design, Kirchhoff's laws that govern power flow are not considered.

The dispatch problem establishes the amount of cross-border power flows on the lines connecting different zones. Supply and demand are then balanced at each region independently, given the established cross-border flows.

B. Unit Commitment and Topology Control

Once the dispatch model is solved, we move to the problem at the regional level, where we fix power flows for boundary lines. For each region, we solve the problem of co-optimizing generation unit commitment and topology control. The problem is formulated using a linearized approximation of Kirchhoff's power flow equations. In order to secure the system against contingencies and forecast errors, we employ reserve requirements in the formulation [28] and allow for demand response, priced at a high valuation. We thus circumvent an explicit enumeration of $N-k$ reliability constraints in the formulation, although the obtained solution can be checked for $N-k$ reliability ex post with feasibility cuts being added as needed. The day-ahead unit commitment problem can be formulated as follows:

$$\min \sum_g \sum_t (C_g p_{gt} + K_g u_{gt} + S_g v_{gt}) + \sum_n \sum_t V_n l_{nt} \tag{6}$$

$$\sum_{k\in\delta^-(n)} f_{kt} - \sum_{k\in\delta^+(n)} f_{kt} + \sum_{g\in g_n} p_{gt} + r_{nt} + TA_{nt} = D_{nt} - l_{nt},\ \forall n,t, \tag{7}$$

$$f_{kt} - B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0,\ \forall k=(m,n),t, \tag{8}$$

$$-f_{kt} + B_k(\theta_{mt} - \theta_{nt}) - M_k(1 - z_{kt}) \le 0,\ \forall k=(m,n),t, \tag{9}$$

$$-TC_k z_{kt} \le f_{kt} \le TC_k z_{kt},\ \forall k,t, \tag{10}$$

$$0 \le r_{nt} \le R_{nt},\ \forall n,t, \tag{11}$$

$$p_{gt} \ge P_g^- u_{gt},\ \forall g,t, \tag{12}$$

$$p_{gt} + sr_{gt} \le P_g^+ u_{gt},\ \forall g,t, \tag{13}$$

$$p_{gt} + fr_{gt} + sr_{gt} \le P_g^+,\ \forall g,t, \tag{14}$$

$$p_{gt} - p_{g,t-1} + sr_{gt} + fr_{gt} \le R_g^+,\ \forall g,t, \tag{15}$$

$$p_{g,t-1} - p_{gt} \le R_g^-,\ \forall g,t, \tag{16}$$

$$\sum_{g\in g_r} fr_{gt} + \sum_{g\in g_r} sr_{gt} \ge TR_{t,r}^{req},\ \forall t,r, \tag{17}$$

$$fr_{gt} \le FR_g,\ \forall g,t, \tag{18}$$

$$\sum_{g\in g_r} sr_{gt} \ge SR_{t,r}^{req},\ \forall t,r, \tag{19}$$

$$\sum_{q=t-UT_g+1}^{t} v_{gq} \le u_{gt},\ \forall g, t \ge UT_g, \tag{20}$$

$$\sum_{q=t+1}^{t+DT_g} v_{gq} \le 1 - u_{gt},\ \forall g, t \le |T| - DT_g, \tag{21}$$

$$v_{gt} \ge u_{gt} - u_{g,t-1},\ \forall g,t, \tag{22}$$

$$v_{gt}, fr_{gt}, sr_{gt} \ge 0,\ \forall g,t, \tag{23}$$

$$u_{gt} \in \{0,1\},\ \forall g,t, \tag{24}$$

$$z_{kt} \in \{0,1\},\ \forall k,t. \tag{25}$$

The objective (6) is to minimize total costs, which are defined by the sum of fuel costs, minimum load costs, startup costs and demand response costs over a horizon of 24 hours. Constraints (7) enforce power balance in each bus. The day-ahead flow of power into bus n, determined by day-ahead dispatch, is denoted as TA_{nt} and is nonzero only for boundary buses. Constraints (8) and (9) 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. The introduction of big-M values 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 by constraints (10). Constraints (11) enforce maximum limits on the renewable power that can be generated at each bus. We allow for the spillage of excess renewable generation, although this assumption can be easily relaxed in order to represent must-take renewable supply. Constraints (12) impose minimum generator capacity limits, and constraints (13) and (14) impose the constraint that maximum generator capacity needs to be allocated between energy, and fast and slow reserves (fr_{gt} and sr_{gt}). Slow reserve is the additional generating capacity that is readily available by increasing the power output of generators that are online while fast reserve is the additional generating capacity that is not synchronized but can be brought online in real time. Minimum and maximum ramp rates are enforced by constraints (15) and (16). Constraints (17) impose a minimum requirement on total reserve and upper limits on the provision of fast reserve are enforced by constraints (18). Minimum requirements for online slow reserve are imposed by constraints (19). Minimum up and down time constraints of generators are enforced in (20) and (21). Constraints (22) represent the logical relation between unit commitment variables and start-up variables. Finally, non-negativity and integrality of variables are imposed by constraints (23) to (25).

The reserve requirements that are utilized in our model commit excess capacity throughout the entire system, without specifying the location of these reserves within a given zone. However, as recent research suggests [29], [30], the placement of these resources is crucial since congestion can limit the deliverability of reserves, resulting in the disqualification of large amounts of capacity. An endogenous representation of

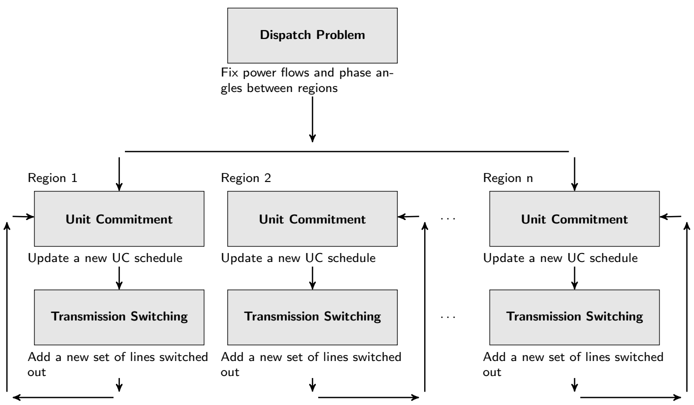


Fig. 1: Decomposition Approach

forecast uncertainty and outages through forecast error scenarios, $N-k$ constraints and the endogenous representation of real-time recourse would overcome this difficulty and result in a model that optimally locates reserves. Rather than focusing on the computational challenges associated with a stochastic, contingency constrained transmission switching model, the present paper analyzes the policy implications of transmission switching. In order to analyze the impact of reserve deliverability, we derate transmission capacities to 90% of their physical limit [5], [31]. This is inspired by current operating practice in European cross-border trading, whereby the total transmission capacity (TTC) is derated to its available transfer capacity (ATC) by subtracting a transmission reliability margin (TRM) [32].

III. Decomposition Approach

Although the above formulation is a mixed integer linear program (MILP) which can be fed into state-of-the-art MILP solvers, it remains computationally intractable on large-scale power systems. This motivates a decomposition approach, in line with the approach employed by Hedman et al. [19]. In particular, we separate the problem into two subproblems, the unit commitment problem and the transmission switching problem, and iterate among the two problems.

Unit commitment is solved first, with transmission switching variables fixed to their current status. At each iteration, we obtain a new commitment schedule for each zone over 24 hours as a solution of the unit commitment problem. Once the unit commitment problem is solved, we next solve the transmission switching problem where the updated unit commitment schedule is fixed and the optimal switching decisions z_{kt} are determined for the given unit commitment configuration. As a result of the transmission switching problem, we obtain a set of lines which should be switched out over the following iterations. At each iteration of the decomposition, we permit at most one line switch per hour and per region[1]. This is motivated by computational and reliability considerations, and also by the fact that significant efficiency gains from topology control have been observed by only switching a small number of lines [16], [21], [26].

Once a line is selected for switching in a given iteration, its status is fixed in subsequent iterations. This implies that constraints (8), (9) and (10) are discarded for those lines that are determined to be switched out at previous iterations. The following constraint is then added to limit the number of new lines that can be switched out at the current iteration:

$$\sum_{k \in \hat{K}_t} (1 - z_{kt}) \leq 1, \ \forall t,$$

where $\hat{K}_t$ represents the set of lines within a region that are not switched off in hour t.

The transmission switching problem is further decomposed into 24 subproblems, such that each subproblem corresponds to each hour. However, due to the ramping constraints (15) and (16) that restrict generation amounts over two consecutive hours, we solve the subproblems sequentially from hour 1 to hour 24 with ramping constraints of hour t modified as follows.

$$p_{gt} - \hat{p}_{g,t-1} + \hat{sr}_{gt} + \hat{fr}_{gt} \leq R_g^+, \ \forall g, \tag{26}$$

$$\hat{p}_{g,t-1} - p_{gt} \leq R_g^-, \ \forall g, \tag{27}$$

$$\hat{p}_{g,t+1} - p_{g,t} + \hat{sr}_{g,t+1} + \hat{fr}_{g,t+1} \leq R_g^+, \ \forall g, \tag{28}$$

$$p_{gt} - \hat{p}_{g,t+1} \leq R_g^-, \ \forall g, \tag{29}$$

where $\hat{p}_{gt}$, $\hat{sr}_{gt}$ and $\hat{fr}_{gt}$ are the solutions of the unit commitment problem of the same iteration. Constraints (26) and (27) enforce ramping rates between hours $t-1$ and t while constraints (28) and (29) enforce ramping rates between hours t and $t+1$. Each time the subproblem of hour t is solved, we fix $\hat{p}_{gt}$ to the obtained solution value for use in the subproblem of the following time period, which ensures that ramp rates are respected over the entire horizon. This decomposition procedure reduces the solution time of the transmission switching problems considerably, although optimality cannot be guaranteed.

As indicated in Fig. 1, the unit commitment and transmission switching problem are solved iteratively in order to obtain an increasing set of lines that are to be switched at a given hour. This leads to an improved unit commitment schedule over iterations. This decomposition approach produces a solution to the problem over the entire continental European network within an acceptable amount of computing time. Although the solution obtained from our approach cannot be guaranteed to be optimal since our approach is heuristic, we demonstrate significant cost reductions in Section V.

In the case of a single iteration of the decomposition proposed in Fig. 1, we obtain an open-loop optimization. This approximates current practice in European markets, whereby suppliers commit units in order to meet their reserve and trading commitments and the TSO subsequently balances the network through transmission switching and re-dispatching.

IV. Data

A. Transmission Network

We use the ENTSO-E System Study Model (STUM) [33]. This model represents the power system of the ENTSO-E

[1]This implies that the number of lines that can be switched for each hour and for each region cannot exceed the number of iterations of the decomposition algorithm, as shown in Fig. 1.

TABLE I: Summarizing statistics for each country

Country	Code	#reg. [a]	$\vert N\vert$[b]	$\vert K\vert$	$\vert G\vert$	Cap.[c]	Country	Code	#reg.	$\vert N\vert$	$\vert K\vert$	$\vert G\vert$	Cap.
Albania	AL	1	38	52	14	2,251	Croatia	HR	1	27	32	9	2,153
Austria	AT	1	82	114	24	7,037	Hungary	HU	1	53	63	19	7,518
Bosnia	BA	1	37	48	12	2,665	Italy	IT	3	781	977	221	47,075
Belgium	BE	1	81	152	21	15,002	Luxembourg	LU	1	20	18	5	1,367
Bulgaria	BG	1	64	84	20	6,591	Montenegro	ME	1	14	17	3	781
Switzerland	CH	1	169	244	79	15,542	FYROM	MK	1	10	9	4	729
Czech Repiblic	CZ	1	75	93	23	9,113	Netherlands	NL	1	81	100	51	17,207
Germany	DE	5	1,296	1,603	302	65,669	Poland	PL	1	164	250	47	17,666
Denmark	DK	1	103	111	6	1,152	Portugal	PT	1	192	305	42	7,410
Spain	ES	5	1,021	1,444	279	60,320	Romania	RO	1	132	192	39	10,592
EU	EU	1	274	0	1	100	Serbia	RS	1	86	112	20	6,499
France	FR	8	1,676	2,146	772	106,662	Slovenia	SI	1	16	15	3	1,467
Greece	GR	1	56	80	19	6,846	Slovakia	SK	1	36	43	24	6,230

[a] Number of regions within country.
[b] $|N|$: number of buses, $|K|$: number of transmission lines, $|G|$: number of generators.
[c] Total generation capacity (MWh)

TABLE II: Marginal cost (€/MWh)

	Nuclear	Lignite	Coal	Gas	Oil
Cost	3.6	1.4	17.3	25.2	44.6

TABLE III: Total daily load and renewable generation of 4 representative days in 2013

	06/01	10/05	11/29	12/10
Total load (MWh)	5,752,143	5,955,226	8,041,012	8,110,625
Total renewable (MWh)	936,802	224,368	1,107,148	217,700
Renewable/Load (%)	16.3%	3.8%	13.8%	2.7%

Regional Group Continental Europe synchronous area and consists of 25 countries, 6,584 buses, 8,799 transmission lines and 2,059 generators. In line with the fact that certain countries are operated by multiple TSOs, in the database each country is further decomposed in regions based on geographic information and the existing partitioning of TSOs. The statistics of each country are summarized in Table I.

B. Generation System

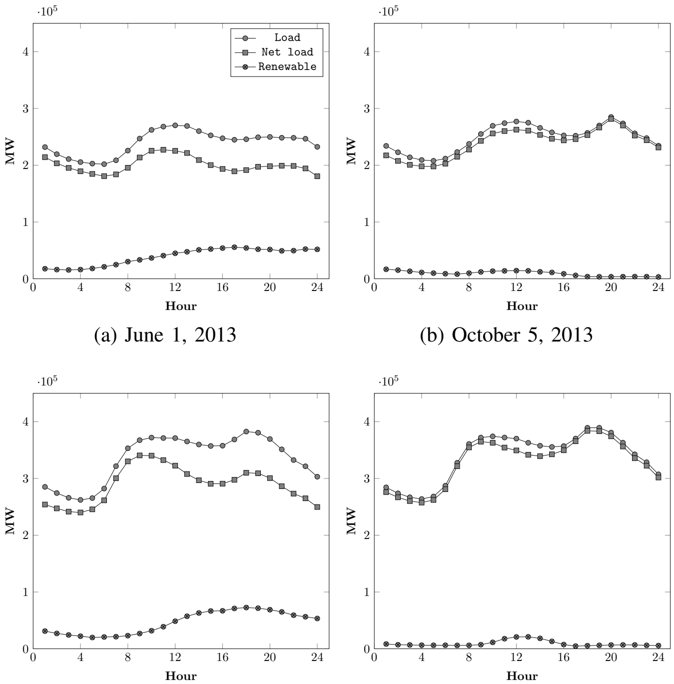
We divide generators into six types according to fuel: nuclear, lignite, coal, gas, oil and hydro. We have used fuel prices in [8] to compute the marginal costs shown in Table II. Since generator data obtained from the ENTSO-E database does not specify the fuel type of individual generators, we assign a fuel type to each generator in the database by taking into account the fuel generation mix of each country in 2013 [34]. Since the total capacity of units with a technical maximum at or above 100MW accounts for more than 90% of the total generating capacity in the system, we simplify the representation of generators with a capacity below 100MW by ignoring their unit commitment constraints. The number of generators and the amount of generating capacity in each country are given in Table I. We assume that gas and oil units are classified as fast generators, and nuclear, coal and lignite units are classified as slow generators. Slow generators are limited to providing slow reserves whereas fast generators can provide slow as well as fast reserves. 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 [30].

C. Renewable Generation

We consider two sources of renewable supply, wind and solar power. Nine countries (Germany, Spain, France, Denmark, Italy, Netherlands, Poland, Portugal and Romania) are assumed to produce wind power and three countries (Germany, Spain and Italy) are assumed to produce solar power. The wind and solar power production of the remaining countries in 2013 was negligible [34], and their production is therefore ignored. Since we were only able to find wind and solar power production data at an hourly resolution for Germany, we apply the hourly renewable production profile of Germany identically to all countries. The resulting hourly renewable production of each country is assumed to be distributed evenly among the buses within the country.

D. 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 demand, as well as high and low renewable supply. Hourly load and monthly renewable generation data of European countries can be obtained from the ENTSO-E database [35]. Table III shows the total amount of consumption and renewable energy production over 24 hours for each of the four representative days that we choose. June 1 and October 15 are chosen as days during which load is relatively low, whereas November 29 and December 10 are days when the load level is relatively high. June 10 and November 29 correspond to high renewable generation and October 15 and December 10 correspond to low renewable generation. Thus, net load is lowest on June 1 and highest on December 10. Fig. 2 depicts the hourly variation of demand, renewable generation and net load for each of the four representative days.



(a) June 1, 2013 (b) October 5, 2013

(c) November 29, 2013 (d) December 10, 2013

Fig. 2: Hourly load and renewable production of 4 representative days in 2013

E. Parameter settings

The transmission capacity of lines is derated by 10% in order to enhance reserve deliverability [5], [31]. The total reserve and online slow reserve requirements are set at 10% and 5% of hourly load, respectively. Demand response valuation is assumed equal to 1,000€/MWh. We exploit the computational tractability of our decomposition in order to conduct a sensitivity analysis of our results with respect to various parameter settings, including line capacity, reserve requirements, demand response valuation, as well as the level of demand and renewable supply.

F. Numerical Experiment Settings

Our numerical experiment was performed on a 2.4 GHz Intel Core i5 processor with 8GB RAM. We solved all MILPs and LPs using CPLEX 12.6 with default parameter settings. Our decomposition approach was applied on the level of 43 regions, shown in Table I. The first unit commitment solution corresponds to the case where all transmission lines are in service. In order to obtain solutions corresponding to the coordination of unit commitment and topology control, we further executed five iterations of transmission switching and unit commitment, with a run time limit of five minutes for each unit commitment problem at the regional level. Hence, we solved 43×6 unit commitment problems and 43×24×5 transmission switching problems in total. We used the indicator constraints option of CPLEX for modeling the big-M logical constraints of the transmission switching problem. The option tends to be more robust numerically than a conventional

TABLE IV: Problem size

	Variables		Constraints		Binaries	
	Avg.	Max.	Avg.	Max.	Avg.	Max.
UC[a]	17,137	59,328	11,244	33,076	428	1,176
TS[b]	1,209	4,242	1,016	3,224	185	619

[a] UC: Unit commitment problem.
[b] TS: Transmission switching problem.

TABLE V: Solution time and final gap (time in seconds and gap in %)

		06/01	10/05	11/29	12/10
UC	Average time	42.42	42.72	23.39	11.14
	Maximum time	300.00	300.00	236.52	99.86
	Total time	10,944.39	11,022.98	6,036.94	2,876.29
	Average gap	0.04	0.11	0.00	0.00
	Maximum gap	2.03	4.05	0.00	0.00
TS	Average time	0.43	0.33	0.23	0.17
	Maximum time	6.85	6.73	7.85	6.38
	Total time	2,269.50	1,727.29	1,202.88	888.08

big-M formulation that does not involve reasonably small M values. Table IV describes the average and maximum problem size over the 43 regions for each type of problem. Table V shows the average solution time and final gaps for each type of problem and each scenario. The final gap is the relative gap between the best integer solution and the best bound at termination. The final gap of the transmission switching problem is not reported because optimal solutions were found within five minutes in all cases. We observe that a run time limit of five minutes is adequate for obtaining satisfactory solutions to both the unit commitment as well as transmission switching problems, with most of the run time being dedicated to solving the unit commitment problems. We also note that we are able to obtain a solution for an industrial scale problem within running times that are acceptable in a day-ahead operational setting.

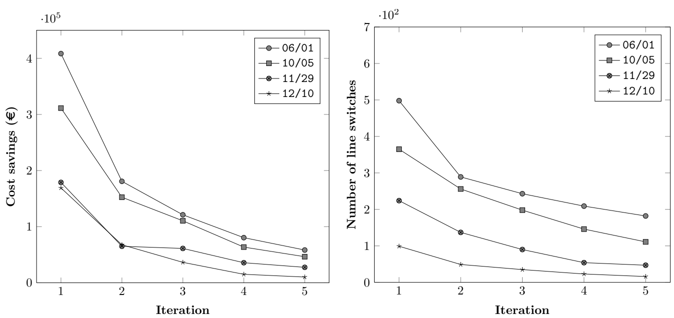
V. Results and Discussion

A. Cost Savings

Table VI presents a breakdown of total costs and the cost savings achieved from transmission switching for each scenario, where 'Base solution' refers to the first unit commitment solution obtained under the assumption that all transmission lines are in service and 'TS solution' refers to the solution obtained after five more iterations among transmission switching and unit commitment. Hence, at most five lines are allowed to be switched out at each hour and for each region. We can see that the daily savings achieved due to topology control range between 0.30 million euros to 0.85 million euros depending on the scenario, which amount to 0.30%-2.03% of the total cost of the base solution. Note that the main cause of cost savings varies depending on the scenarios. The majority of cost savings is attributed to the reduction of generation costs when load is relatively low (06/01 and 10/05) while cost savings are driven by decreased reliance on demand response when load is relatively high (11/29 and 12/10). Note, however, that the amount (in MWh) of demand response relative to total load

TABLE VI: Cost savings achieved by transmission switching

Scenario	Cost (€)	Base solution	TS solution	Savings
06/01	Generation	29,545,240	28,758,644	786,596
	Min load	11,914,000	11,865,977	48,023
	Startup	176,898	174,512	2,386
	Demand response	133,341	121,214	12,127
	Total	**41,769,479**	**40,920,348**	**849,131**
10/05	Generation	39,108,312	38,673,415	434,897
	Min load	13,865,703	13,661,071	204,632
	Startup	536,743	500,747	35,996
	Demand response	667,006	658,275	8,732
	Total	**54,177,764**	**53,493,507**	**684,257**
11/29	Generation	57,799,454	57,636,496	162,958
	Min load	16,385,999	16,356,765	29,234
	Startup	842,508	835,249	7,259
	Demand response	866,388	697,406	168,981
	Total	**75,894,348**	**75,525,916**	**368,432**
12/10	Generation	78,366,354	78,256,510	109,844
	Min load	18,185,922	18,191,583	-5,661
	Startup	1,188,564	1,189,223	-659
	Demand response	1,037,902	842,839	195,063
	Total	**98,778,742**	**98,480,155**	**298,587**



(a) Cost savings (b) Number of line switches

Fig. 3: Cost savings and number of line switches over iterations

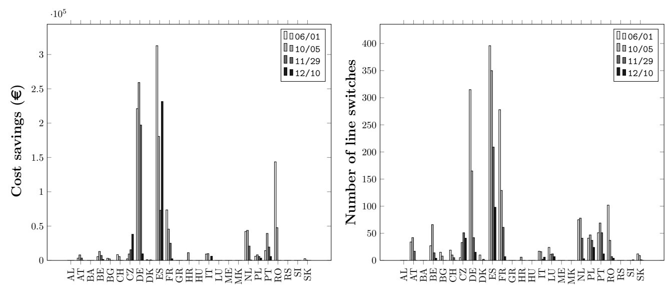
is insignificant, e.g., 0.012% of load is lost in the case of the 12/10 scenario. The contribution from minimum load costs and startup costs is less substantial.

Fig. 3 presents the evolution of cost savings and number of line switches over the five iterations of the decomposition algorithm. We can first observe that more line switches tend to result in greater cost savings. Also, in line with existing literature [16], [21], [26], we find that a single line switch at each hour for each region is capable of delivering significant cost savings. This reinforces the argument that transmission switching is a minimally intrusive, implementable option, which is compatible with current practice in Europe. Approximately half (45%-56%) of the cost savings obtained after five iterations are achieved in the first iteration, while additional iterations provide cost savings at a rapidly decreasing rate.

An interesting finding of our analysis is the fact that cost savings exhibit a negative correlation to net load. We can observe that as net load increases (from the 06/01 scenario to the 12/10 scenario) cost savings decrease. This observation can be explained by the fact that the efficiency gains of topology control are achieved by shifting power production

TABLE VII: Effect of transmission switching on daily generation mix (in 1,000MWh)

Scenario	Solution	Nuclear	Lignite	Coal	Gas	Oil	Renewable	Hydro
06/01	Base	2,243	1,204	584	333	28	899	604
	TS	2,274	1,200	583	305	24	904	606
10/05	Base	2,740	1,214	826	465	33	216	604
	TS	2,747	1,221	822	456	29	216	606
11/29	Base	3,195	1,240	1,084	942	45	1,081	607
	TS	3,193	1,244	1,091	934	43	1,082	608
12/10	Base	3,341	1,231	1,341	1,383	146	211	608
	TS	3,338	1,236	1,343	1,384	143	211	608



(a) Cost savings (b) Number of line switches

Fig. 4: Cost savings and number of line switches by country

from resources with higher marginal cost to resources with lower marginal cost. When net load is lower, there exists more generating capacity from resources with lower marginal cost that can be used if the reconfiguration of the transmission network allows it. This finding is supported by the results presented in Table VII, where we present the shift in the power generation mix between the Base Solution and TS Solution. We observe that transmission switching enables a shift to units with lower marginal cost such as lignite, hydro, and non-hydro renewables instead of more expensive resources such as coal, gas, and oil. Note, however, that power production from coal and gas increase in the case of the 12/10 scenario, which is due to the reduction of demand response. The relation between cost savings and net load is explained further in the subsequent sensitivity analysis.

Fig. 4 presents the cost savings and number of line switches by country. We observe that Germany and Spain, which operate the greatest transmission networks with the highest generation capacities and produce the majority of renewable power, benefit most from topology control. France, the Netherlands, Portugal and Romania also contribute to the cost savings to a certain degree.

B. Unit Commitment and transmission switching

Table VIII shows the effect of transmission switching on the number of committed units by generator type. The results confirm the observation of Table VII that transmission switching tends to shift production to technologies with lower fuel cost, especially in days of medium load.

Table IX presents the statistics of unit commitment decisions, and how these are influenced by topology control. The

TABLE VIII: Effect of transmission switching on number of committed generators by fuel type

Scenario	Solution	Nuclear	Lignite	Coal	Gas	Oil
06/01	Base	3,051	2,432	2,364	2,117	279
	TS	3,051	2,434	2,342	2,074	279
10/05	Base	3,297	2,494	3,207	2,477	279
	TS	3,293	2,492	3,120	2,395	279
11/29	Base	3,536	2,514	3,949	3,538	354
	TS	3,534	2,514	3,946	3,499	352
12/10	Base	3,608	2,515	4,431	4,656	569
	TS	3,608	2,515	4,429	4,663	570

TABLE IX: Effect of transmission switching on unit commitment statistics

Scenario	Solution	Avg. On	Always On	Always Off
06/01	Base	426	366	296
	TS	423	359	297
10/05	Base	490	408	219
	TS	482	402	227
11/29	Base	579	442	109
	TS	576	441	111
12/10	Base	657	515	22
	TS	658	512	21

headings ‘Avg. On’, ‘Always On’, and ‘Always Off’ represent the average number of generators on per hour, the number of generators that are always on, and the number of generators that are always off, respectively. The change in the average number of generators that are operating per hour indicates that topology control enables a number of generators to be shut down. Moreover, we observe that the number of generators that are on during the entire day decreases and the number of generators that are off during the entire day increases as a result of topology control. However, unlike other scenarios, the results of the 12/10 scenario seem to be unaffected by transmission switching since total power production increases due to transmission switching.

Fig. 5 illustrates how frequently a line is switched out over 24 hours, where the x-axis represents the number of times a line is switched, ranging from 1 to 24, and the y-axis represents the corresponding number of lines that are switched out for the given frequency. We observe that for most of the lines that are switched out at least once over the course of the day, the number of times that they are switched out is small (less than 3 times for more than 80% of these lines). This suggests that daily transmission switching patterns change substantially depending on hourly load and renewable production patterns, thereby varying substantially over different hours of the day. This result, which is in line with previous findings in the literature [18], indicates that it it is necessary to optimize hourly network topology by taking into account hourly load and renewable patterns rather than optimizing against a static network whose conditions do not not change over multiple time periods. This observation is demonstrated more clearly in Fig. 6, where we compare the benefits of dynamic versus static topology control by plotting

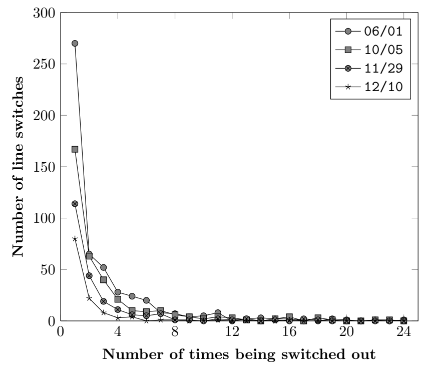
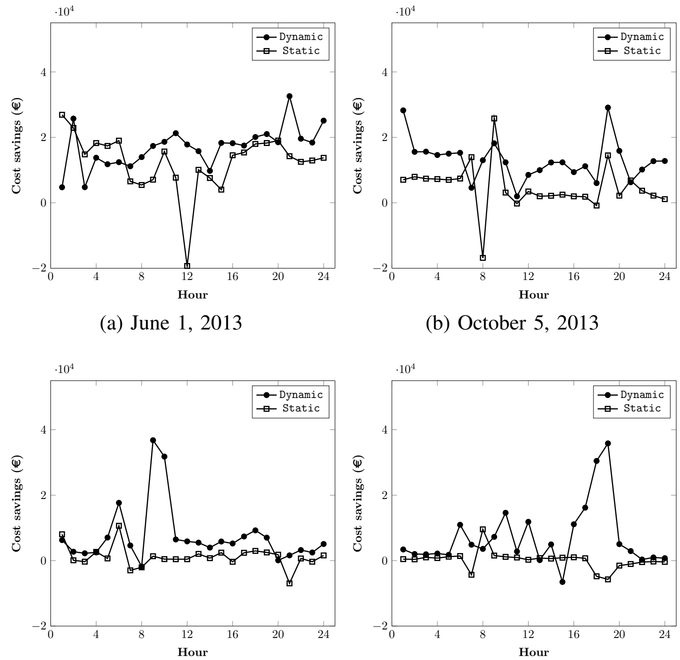


Fig. 5: Frequency of line switching



(a) June 1, 2013

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(c) November 29, 2013

(d) December 10, 2013

Fig. 6: Cost savings of dynamic versus static topology control

the hourly cost savings achieved in both cases. We observe that static topology control (i.e. a single reconfiguration of the network for the entire day) produces negative hourly cost savings more often. The cost savings of topology control over the entire day are enhanced by dynamic control. This calls for a systematic approach to topology control in the European system by embedding the optimization of topology control in operations, since operators cannot rely on ad hoc, time-invariant choices of lines. Moreover, the influence of unit commitment on transmission switching patterns implies that transmission switching and unit commitment should be optimized jointly, although this is hampered by the existing European market design whereby congestion management is separated from unit commitment.

C. Sensitivity Analysis

We further analyze the sensitivity of the results with respect to various parameters, including load, renewable supply, line

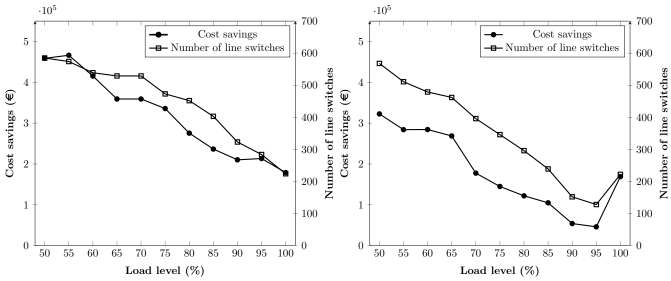

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Fig. 7: Cost savings and number of line switches as a function of load level

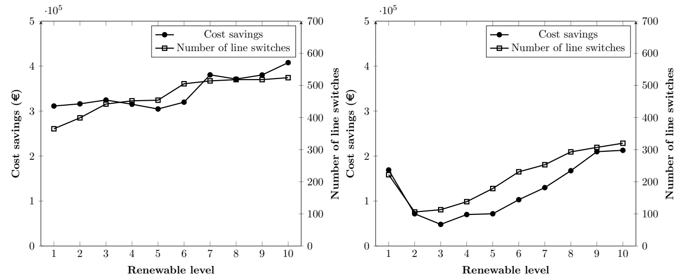

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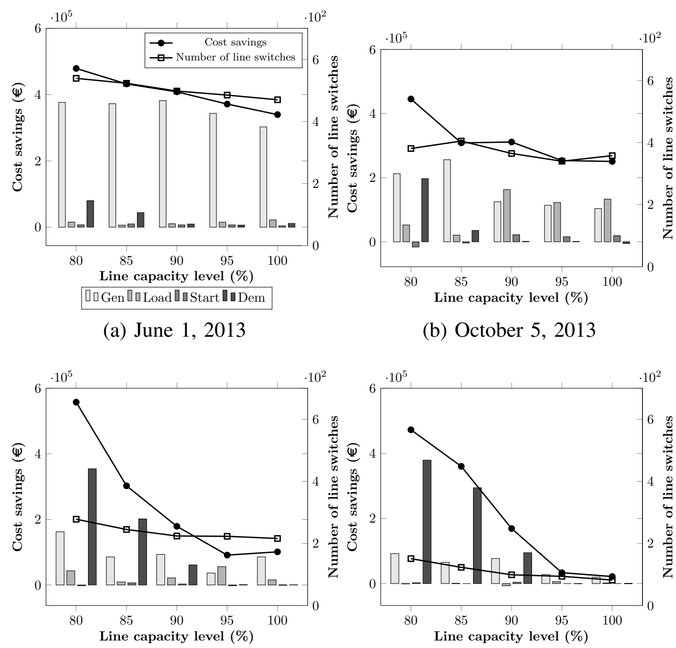
Fig. 8: Cost savings and number of line switches as a function of renewable production level



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(c) November 29, 2013 (d) December 10, 2013

Fig. 9: Cost savings and number of line switches as a function of transmission line capacity

capacity, reserve requirements and the valuation of demand response. Note that we allow at most one line switch at each hour and for each region in all subsequent numerical tests.

Motivated by the ambitious renewable integration and energy efficiency targets of the European Commission, we proceed with an analysis of the impact of load and renewable production on our results. We choose the high-load scenarios 11/29 and 12/10 and reduce their load levels by up to 50%. Fig. 7 illustrates cost savings and the number of line switches as a function of load level. We confirm our previous observation that cost savings decrease as demand increases. The increase in cost savings in the far right point in Fig. 7(b) violates this pattern due to transmission switching enabling a reduction in demand response costs. Transmission switching appears to be more beneficial on the 11/29 scenario than on the 12/10 scenario, although load levels for both scenarios are comparable. This difference can be explained by the fact that renewable production on the 11/29 scenario is five times higher than that of the 12/10 scenario. As a result, the average cost savings of topology control on 11/29, €715 per line switch, are far greater than the corresponding savings on 12/20, €474 per line switch.

In order to analyze the sensitivity of our results on renewable production, we vary renewable production in the low-renewable scenarios 10/05 and 12/10 by a factor ranging between 1 and 10. Fig. 8 demonstrates the cost savings and number of line switches as a function of renewable production. Note that the renewable output of the 10/05 and 12/10 scenarios reaches up to 38% and 27% of total demand respectively. We observe that cost savings and the number of line switches increase as a function of renewable production. This trend can be explained by the fact that topology control enables greater utilization of renewable production.

The preceding sensitivity results suggest that topology control becomes especially relevant for Europe as the share of renewable production is expected to increase and energy efficiency is expected to diminish system demand.

As we explain in Section IV, we reduce the transmission capacity of lines by 10% in the reference model, in order to ensure improved deliverability of reserves [5], [31]. Fig. 9 presents cost savings as a function of line capacity, whose rating ranges between 80% and 100% of the original line capacity. The bar chart represents a breakdown of cost savings for each level of line capacity. The headings 'Gen', 'Load', 'Start', and 'Dem' represent cost savings from generation cost, minimum loading cost, start up cost, and demand response cost, respectively. We observe that cost savings tend to increase as line capacity decreases. The results verify the effectiveness of transmission switching in congestion management. This trend is observed clearly in scenarios of high load (11/29 and 12/10) in which demand response increases noticeably, and cost savings from preventing demand response through transmission switching increase significantly.

In order to test the sensitivity of our results on the level of reserve requirements, we vary total reserve requirements in each region between 2.5% and 15.0% of the regional load. Slow reserve requirements are set equal to half of total reserve requirements. The results are shown in Fig. 10. We observe that cost savings decrease as reserve requirements increase, with the exception of the 12/10 scenario. This inverse relation can be attributed to the fact that when reserve requirements

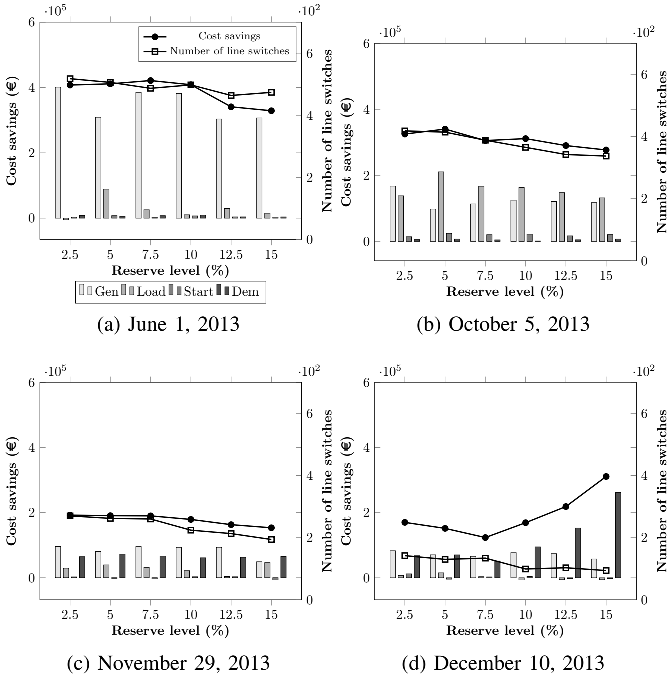

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Fig. 10: Cost savings and number of line switches as a function of reserve level

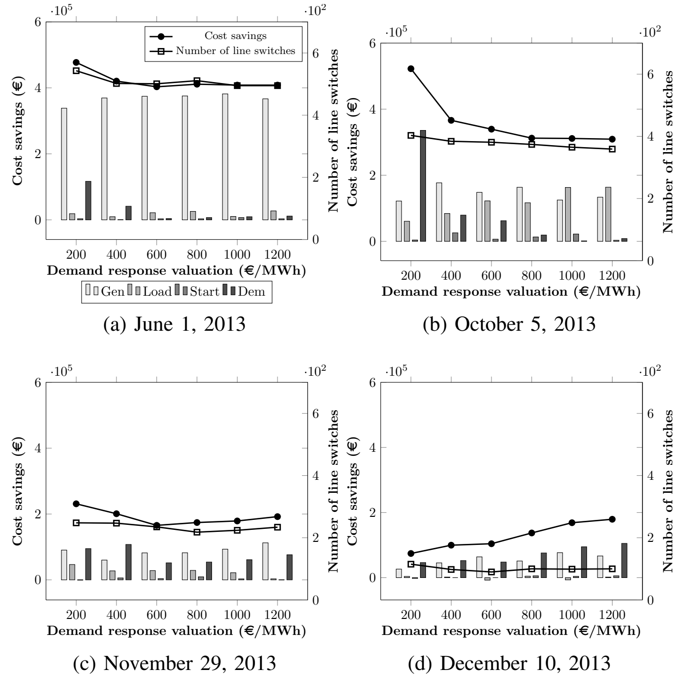

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Fig. 11: Cost savings and number of line switches as a function of demand response valuation

increase, there exists less generating capacity from resources with low marginal cost that can be utilized if topology control permits. Under peak demand conditions (12/10), an increase of reserve requirements requires mobilization of demand response in order to free up generating capacity that is needed for satisfying reserve requirements. In this case, transmission switching is useful since it enables stand-by generators to cover the reserve requirements, that would have been left unused in the absence of transmission switching.

We have noted that the sensitivity results differ under peak demand conditions (the 12/10 scenario) due to the influence of demand response on costs. We now examine the influence of the valuation of demand response on our results. For this purpose, the demand response valuation is varied between €200/MWh to €1,200/MWh and the results are presented in Fig. 11. We note that the cost savings exhibit different behavior depending on load level. In conditions of low load, cost savings from preventing demand response tend to decrease and converge to zero with an increasing cost on unserved load, thereby resulting in the convergence of cost savings. This can be explained by the fact that demand response decreases and reaches a minimum at some point with an increasing penalty on unserved load, whether transmission switching takes place or not. In contrast, under peak load conditions a minimum of demand response cannot be avoided, therefore cost savings from preventing demand response through transmission switching tend to increase with an increasing cost of unserved load. This results in increasing cost savings due to transmission switching.

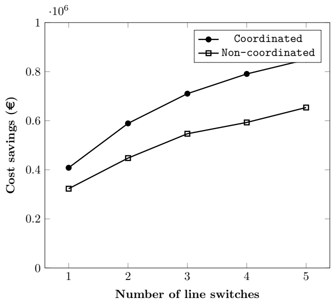
D. Coordination between Unit Commitment and Topology Control

Current market coupling in Europe clears energy through day-ahead exchanges, while congestion is managed within each country by solving a re-dispatching problem in real time. An open-loop optimization with a single iteration of the decomposition algorithm in Fig. 1 is a close approximation of current practice in European markets where nominations of units are followed by congestion management of the transmission network by the TSO. On the other hand, our iterative approach reflects the coordination between unit commitment and topology control at the day-ahead stage. By comparing both cases, we can quantify the benefits of coordination between unit commitment and topology control. Fig. 12 depicts cost savings as a function of number of switches for both cases. The results for the non-coordinated optimization are obtained by solving the transmission switching problem repeatedly, given the fixed unit commitment decision that we obtain when all lines are in service. We observe that the coordination between unit commitment and topology control enhances cost savings by 9.7% to 33.3% depending on the scenario.

VI. Conclusion

In this paper, we analyze the potential of proactive topology control for economic optimization in the continental European power system. We evaluate the impacts of topology control under a range of load and renewable energy production scenarios, followed by a sensitivity analysis of various key parameters that drive costs.

Our findings indicate that topology control can deliver significant cost savings to the European network, ranging between 0.30% and 2.03% of the total cost depending on



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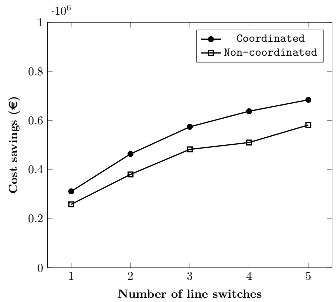

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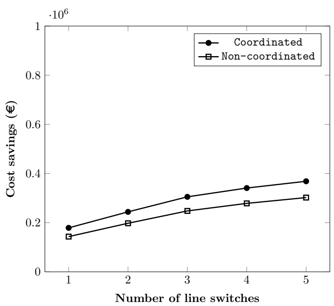

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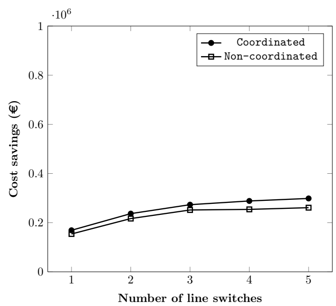

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Fig. 12: Cost savings of coordination versus sequential optimization of unit commitment and topology control

net load. We observe that these cost savings are greater in relative terms when net load is lower, i.e., low load and high renewable supply, since topology control enables mid-merit units to replace out-of-merit high cost units in the fuel mix. Moreover, transmission switching has a significant impact on unit commitment. With the increase of renewable energy integration and the decrease of load due to the improvement of energy efficiency within Europe, it is expected that net load will decrease over time. This increases the relevance of topology control in improving the efficiency of the system as Europe moves towards achieving its ambitious long-term renewable energy integration and energy efficiency goals.

The evaluation of the benefits of transmission switching as a reactive real-time decision, after uncertainty has been revealed, imposes a substantial computational burden on the analysis. In future research we intend to resort to high performance computing in order to conduct a detailed Monte Carlo simulation of transmission switching as a reactive measure.

In order to secure the system against contingencies and forecast errors, we employ reserve requirements in the formulation [28]. We thus circumvent an explicit enumeration of $N-k$ reliability constraints in the formulation, although the obtained solution can be checked for $N-k$ reliability ex post. In order to enhance the deliverability of reserves, we derate transmission capacities to 90% of their physical limit [5], [31]. Our goal in future research is to overcome the computational challenges associated with a stochastic, contingency constrained transmission switching model.

In our paper we assume that, following the clearing of the day-ahead market, TSOs resolve congestion within their respective zones while respecting the amount of international power exchange that is determined from the day-ahead market [12]. A relaxed variation of this model, which is closer to practice in European TSO operations, assumes that TSOs resolve congestion while striving to respect the net power consumption of each zone [36]. This would indeed result in transmission switching of one region impacting neighboring regions. This is in fact an element that is missing from existing literature on transmission switching, that typically considers systems in isolation. In future research we are interested in relaxing the model by assuming that TSOs may violate day-ahead cross-border flows (while maintaining net country positions) and analyze the impacts of transmission switching within one region on neighboring systems.

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