Cross-border reserve markets: network constraints in cross-border reserve procurement

Kenneth Van den Bergh^a, Kenneth Bruninx^{a,b,c} and Erik Delarue^{a,c*}

^aKU Leuven, Celestijnenlaan 300 box 2421, B-3001 Leuven, Belgium

^bVITO, Boerentang 200, B-2400 Mol, Belgium

^cEnergyVille, Thor Park 8310, B-3600 Genk, Belgium

*Corresponding author: erik.delarue@kuleuven.be (email); +32 16 32 25 21 (phone number)

Abstract. *Cross-border reserve markets—the procurement and activation of reserves in one control area to maintain system balance in another control area—can lead to increased cost-efficiency and reliability. However, network constraints impose limits on cross-border reserve coordination. Transmission capacity allocation in the reserve market is a complex problem, as it happens under uncertainty and interferes with transmission capacity allocation in energy markets. This paper studies network constraints in the reserve procurement phase, by means of a simulation model and scenario analysis. Three different approaches are proposed and evaluated based on a case study of the Central Western European electricity system. Towards this aim, a dedicated model is developed to simulate the day-ahead energy market, the day-ahead reserve procurement and the real-time reserve activation. In a case study of the Central Western European power system, we show that the best reserve market outcome—weighing cost-efficiency and system reliability—is obtained when reserve activation scenarios are considered in the procurement phase. Policy makers should design, in close cooperation with regulators and system operators, efficient and robust transmission capacity allocation procedures for cross-border reserve markets. This paper can help them to do so as it demonstrates the impact of transmission capacity allocation on cross-border reserve markets.*

Keywords. *Reserves markets; cross-border balancing; transmission capacity allocation.*

I. INTRODUCTION

Cross-border reserve markets are gaining attention in academia and industry, in light of the prospect of increased cost-effectiveness and enhanced system reliability. In European reserve markets, Transmission System Operators (TSOs)—who bear the final responsibility to balance the generation and consumption of electrical energy on an instantaneous basis within their control area—procure and activate operational reserves to maintain the system balance (ENTSO-E, 2014a).

Today, reserve markets in Europe are mainly national markets. Although certain exceptions exist, the basic rule is that every control area is responsible for the dimensioning, procurement and activation of its reserves (Baldursson et al., 2016). In cross-border reserve markets, TSOs can activate and/or procure reserves in other control areas. Moreover, the dimensioning of reserves can be coordinated between different control areas. It is generally accepted in the scientific literature that cross-border reserve markets increase social welfare and operational reliability, since the amount of reserves needed in the system can be decreased (due to spatial smoothing of imbalances) and the cost of procuring and activating reserves can be reduced (due to spatial arbitrage between different control areas) (Vandezande et al., 2010).

An important issue that is underexposed in the scientific literature and network codes is how cross-border network constraints should be taken into account. Cross-border reserve markets are constrained by the available cross-border transmission capacity. In reserve markets, reserve capacity is procured by TSOs before real-time and—if needed—activated in real-time to deal with system imbalances. In this respect, one should distinguish between reserve procurement—which refers to scheduling of reserve capacity before real-time—and reserve activation—which refers to activating reserve capacity to deliver or consume energy in real-time. Transmission capacity allocation for reserve activation is a problem with a deterministic character, while transmission capacity allocation for reserve procurement has a stochastic character.¹ At the moment that reserve capacity is activated to deliver or consume energy (i.e., in real-time), the system state is known. In other words, the remaining cross-border transmission capacity is known and the impact of activating cross-border reserves on the network can be determined. As such, network constraints in the reserve activation can be taken into account in the same way as network constraints are taken into account in the (day-ahead and intra-day) energy market. At the moment that reserve capacity is procured (i.e., before real-time), the system state is still unknown: it is uncertain whether the procured reserve capacity will be actually activated in real-time and what the remaining real-time cross-border capacity will be at that time. Therefore, it is not straightforward to take network constraints into account in the cross-border procurement of reserves.

This paper proposes a novel approach to include network constraints in the cross-border procurement of reserves. The 2013 Central Western European electricity system (Belgium, Luxembourg, France, Germany and the Netherlands) is considered as a case study. The contributions of this paper to the existing scientific literature are twofold:

¹ In reality, transmission capacity allocation for reserve activation and electrical energy also has a stochastic character as the transmission capacity offered to the real-time market may not be physically available, caused by the zonal market approach applied in Europe. Such effects are however not considered in this paper and the reserve activation is executed assuming perfect foresight on the available transmission capacity. In contrast, the stochasticity in the transmission capacity allocation for reserve procurement is caused by the inherent uncertainty of reserves being activated and the unknown state of the network at that moment. This effect is considered in full in this paper.

- 1) The paper presents a (deterministic) model of the reserve market that takes account of network constraints in cross-border reserve procurement. Our model allows mimicking optimal arbitrage between reserve, energy and transmission capacity markets. Moreover, the model fully considers the real-time reserve activation, simulating the balancing market outcome, and includes intertemporal constraints of thermal power plants;
- 2) The paper quantifies the benefits of cross-border procurement and activation of reserves for the Central Western European system in an extensive case study.

This paper deals only with short-term operational reserves. Long-term reserves—relevant in the framework of system adequacy—are not considered (Luickx et al., 2008). Operational reserves are defined as all possible flexibility options within an electricity system to respond to changes in load or generation within the time frame of minutes to hours (Lannoye et al., 2012). Reserves can be delivered by conventional power plants, demand response, energy storage units and curtailment of renewables (Cochran et al., 2014).

This paper deals with reserve markets in Europe. European reserve markets are characterized by a zonal approach (i.e., every country is—roughly speaking—one control area with one reserve market and assumed to be a copper plate²) and separate energy and reserve market clearing.

The paper continues as follows. Section II discusses the current reserve market design in Europe and gives an overview of the scientific literature on the integration of reserve markets. Section III presents the generation scheduling model (i.e., a unit commitment model) developed for this study and the considered scenarios. Section IV discusses the case study of the Central Western European power system. Results are presented and discussed in Section V. Section VI concludes and formulates policy recommendations.

II. CROSS-BORDER RESERVE MARKETS

This section starts off with an overview of reserve markets in the European electricity system, followed by a review of the scientific literature on cross-border reserve markets.

a. Reserve market design in Europe

Different reserve market designs exist in Europe, depending on the reserve product (see further). However, all reserve markets are characterized by a top-down design, consisting of three consecutive phases. First, the amount of reserves required in the system is determined by each TSO, for its own control area, following sizing rules defined and agreed upon on European level (ENTSO-E, 2013a; De Vos et al., 2012).³ This first step is referred to in this paper as the *dimensioning phase*. The dimensioning phase occurs well before real-time (i.e., weeks to months). Second, each TSO procures reserves in the reserve market from reserve providers (e.g., conventional generators or large consumers) in order to meet the reserve requirement for its control area. Reserve providers may be remunerated for the reserve capacity they sell to the TSO by means of a reservation payment (in €/MW/h). This reservation payment reflects the

² Network constraints within a control area are not considered, only network constraints between control areas (i.e., cross-border) are dealt with in this paper.

³ The amount of fast reserves (i.e., frequency containment reserves) is determined on European level (by ENTSO-E) per synchronous area and then allocated to the respective TSOs in the synchronous area.

opportunity cost that the reserve provider faces by not using the reserve capacity for other purposes (e.g., for generating electricity in case of a generator). This second step is referred to as the *procurement phase* in this paper, but is also sometimes referred to in the literature as the scheduling, reservation or allocation phase. The procurement phase happens after the dimensioning phase but before real-time (i.e., days to months). Third, the TSO activates reserves in real-time to maintain the system balance. Reserve providers may be remunerated by means of an activation payment (in €/MWh) to cover the cost of activating reserves (e.g., fuel costs for a generator).⁴ This final step is referred to as the *activation phase* in this paper, but is also sometimes referred to as the deployment phase in the scientific literature.

In the European system, one distinguishes four different categories of reserve products, based on—amongst other—response time and activation time: Frequency Containment Reserves (FCR), Automated and Manual Frequency Restoration Reserves (aFRR and mFRR) and Replacement Reserves (RR).⁵ FCR are fast reserves which react within seconds in order to keep the system balance within a secure range. FRR react in the time frame of seconds to minutes and are intended to free up FCR and bring the frequency back to its reference level. Automated FRR react faster than manual FRR. In case of drastic imbalances, RR are activated to free up FRR (ENTSO-E, 2013a). The TSO contracts a certain amount of upward and/or downward reserves from each reserve category. Upward reserves are needed to deal with negative system imbalances (i.e., undersupply or overconsumption causing a frequency drop) and downward reserves are needed to deal with positive system imbalances (i.e., oversupply or under-consumption causing a frequency rise).

Although reserve markets in Europe have a similar design—consisting of the same market phases and reserve categories—important differences exist in the actual implementation of these markets. Differences between countries are apparent in the technical product definitions, the procurement procedure, the bid selection and bid activation, the settlement, the imbalance pricing and the overall balancing approach (50Hertz et al., 2014; De Vos et al., 2011; Verpoorten et al., 2016). This hampers the coupling of reserve markets. Therefore, ENTSO-E stresses the importance of harmonization of reserve markets in Europe in its most recent network codes (ENTSO-E, 2014a).

ENTSO-E (2013b, 2014b) describes four possible types of cross-border coordination in reserve markets (in order of increasing level of required coordination):

- *Imbalance netting.* Imbalance netting is exchanging opposite imbalances between control areas in real-time, before activating any reserves. As such, the total amount of reserves that has to be activated decreases, resulting in cost reductions. This type of cross-border coordination entails the lowest technical complexity and is relatively easy to implement. Imbalance netting has an impact on the activation phase.

⁴ The activation of fast symmetrical reserves (i.e., symmetrical frequency containment reserves) is not rewarded with an activation payment as upward activations (resulting in payment from TSO to reserve provider) and downward activations (resulting in payment from reserve provider to TSO) are assumed to cancel each other out.

⁵ The different reserve categories were formerly known in Central Europe as, according to the ENTSO-E Central Europe Operation handbook, primary reserves (i.e., frequency containment reserves), secondary reserves (i.e., automated frequency restoration reserves) and tertiary reserves (i.e., manual frequency restoration reserves and replacement reserves).

- *Common merit order.* TSOs in different control areas activate reserves from one common merit order. As such, the most cost-efficient reserves can be activated in real-time, regardless where they are located. The common merit order has an impact on the activation phase.
- *Exchange of reserves.* Exchange of reserves is contracting of reserves in another control area. As such, the most cost-efficient reserves can be procured, regardless where they are located. Exchange of reserves has an impact on the procurement and activation phase.
- *Reserve sharing.* Reserve sharing is contracting reserves in another control area which are at the same time contracted by another TSO (unlike exchange of reserves where reserves can only be contracted by one TSO). This implies that the total contracted reserve capacity decreases. Therefore, reserve sharing should only be used for reserves with a very low probability of being simultaneously activated by different TSOs. Reserve sharing has an impact on the dimensioning, procurement and activation phase.

Roughly speaking, today's reserve markets in Europe are fully uncoordinated. This implies that every TSO does the dimensioning, procurement and activation of reserves for its own control area, without any coordination with neighboring control areas. However, a limited number of examples of cross-border reserve coordination exist. Especially the cross-border coordination of frequency containment reserves is already well established, with a coordinated dimensioning and (partially) coordinated procurement of FCR (e.g., the Belgian TSO procures FCR in France, and the procurement of FCR is jointly organized by Germany, Switzerland and the Netherlands).⁶ The Nordic countries have had a fully coordinated reserve market since 2002. Other examples are the imbalance netting between seven countries (Belgium, the Netherlands, Germany, Denmark, Czech Republic, Switzerland and Austria) and the reserve sharing of 300 MW mFRR between Belgium (Elia), the Netherlands (Tennet NL) and part of Germany (Tennet DE) (Baldursson, 2016).

ENTSO-E foresees three different approaches that can be used by TSOs to reserve cross-border transmission capacity for the exchange of reserves (in order of increasing integration with the transmission capacity market) (ENTSO-E, 2014a):

- *Reservation based on economic efficiency analysis.* The TSOs reserve cross-border capacity before the transmission capacity auction takes place. The reserve capacity is based on forecasted reserve bids and forecasted energy market price differences.
- *Market-based reservation.* The TSOs reserve cross-border capacity before the transmission capacity auction takes place between market participants. The reserve capacity is based on submitted reserve bids and forecasted energy market price differences.
- *Co-optimized capacity allocation.* The TSOs participate in the transmission capacity auction, together with other market participants, to reserve cross-border capacity simultaneously with the procurement of reserves.

⁶ One of the reasons that cross-border coordination of frequency containment reserves (FCR) is already—to a large extent—in place is a large common European interest. FCR is dimensioned to maintain the system frequency in the time frame of milliseconds in case of a worst-case contingency (e.g., unexpected outage of the largest generation unit). Every country benefits from the services provided by FCR. Moreover, a European sizing of FCR results in lower FCR volumes than a sizing on national basis, due to the low probability that a worst-case outage occurs simultaneously in different countries.

In short, reserve markets in Europe are nowadays mainly national markets, but system operators (and regulators) are drafting network codes that enable cross-border reserve markets. One of the main challenges, however, is to properly account for cross-border network constraints, especially in the cross-border procurement of reserves.

This paper focusses on the exchange of reserves (i.e., coordination in the procurement phase) with co-optimized capacity allocation (i.e., TSOs participate in the transmission capacity auction).

b. Literature on reserve market coupling

Several academic papers advocate for the coupling of reserve markets. For instance, Meeus et al. (2005) and Vandezande et al. (2010) emphasize the importance of cross-border reserve markets in a well-functioning European electricity market. Doorman and van der Veen (2013) discuss qualitatively several balancing market designs and conclude that cross-border balancing increases overall welfare, although market performance varies considerably between the possible market designs.

The benefits of cross-border reserve markets can be quantified by means of two approaches: (1) based on a simulation model of the electricity system, considering scenarios with and without cross-border reserve markets, and (2) based on an empirical analysis of existing cross-border reserve coordination before and after coupling (Newbery et al., 2016). The first approach is used in this paper.

Most papers aiming to quantify (parts of) the benefits of cross-border reserve markets, focus solely on cross-border cooperation in the activation phase. As such, these papers focus on imbalance netting and a common merit order. Vandezande et al. (2009) estimated that the balancing costs in Belgium and the Netherlands could have been 40% lower in 2008 if cross-border netting of imbalances was in place. Similar conclusions are drawn by Gebrekiros and Doorman (2014a), based on a study of the Northern European electricity system, and by Zani et al. (2016) for a case study of Italy, Austria and Slovenia. Van der Weijde and Hobbs (2011) quantify the cost savings that arise from the coordination of reserve activation for a simple 4-node system. Cost savings turn out to be always positive, but the exact magnitude of the savings depends on various system parameters such as cross-border transmission capacity and the conventional generation portfolio. A similar analysis is performed by Oggioni and Smeers (2013). They show, based on an illustrative network, that coordination between different system operators can reduce the cost of real-time counter-trading.

Although most papers deal with cross-border coordination in the activation phase, several contributions also consider cross-border coordination in the dimensioning phase and the procurement phase. Mott MacDonald (2013) looked at hypothetical scenarios for the European electricity system towards 2030 and estimated that integrating balancing markets and sharing reserves could achieve operating cost savings of about €3 billion per year and reduce the required reserve capacity by up to 40%. Newbery et al. (2016) estimated the benefits of interconnectors to increase the efficiency of trading across borders. They conclude that total gains could be as high as €1.3 billion per year for Europe. Van den Bergh et al. (2015) considered a case study of Central Western Europe, indicating operating cost reductions of €27 million per year and increased system reliability when reserve markets are coupled. Their analysis shows also the importance of properly accounting for network constraints in cross-border reserve markets.

Gebrekiros et al. (2013, 2015) develop a model to determine bidding prices and quantities for reserve offers, to procure reserves and to clear the day-ahead energy market, accounting for scheduled reserve capacity and the associated implications on transmission constraints. To ensure the feasibility of cross-border reserve exchanges, a predetermined share of the interconnection capacity between balancing zones is allocated to reserve exchanges. In a case study of the Northern European power system, they show that their approach may lead to operating costs savings up to €2.5 million annually. Building on this work, Gebrekiros and Doorman (2014b) develop a novel algorithm to optimize the share of the NTC between balancing areas that is reserved for reserve exchanges. Gebrekiros et al. (2014) study the impact of hydro inflow in the Nordic system on the optimal cross-border transmission capacity allocation. Gebrekiros et al. assume this optimal NTC share to be constant across the planning period, whereas our approach allows calculating the optimal NTC share at each time step. Farahmand and Doorman (2011) present a model similar to the one we propose to study the integration of the European balancing market, however, not accounting for intertemporal constraints for conventional thermal generation units, such as ramping limitations and minimum up- and down-times. Leveraging this model, Farahmand and Doorman (2012) study the possible benefit of integrating balancing markets in the Northern European power system in 2030. Jaehnert and Doorman (2012) assume reserves may be procured after clearing the day-ahead market. Cross-border procurement is possible if the remaining transmission capacity between zones allows the activation of the procured reserves. We complement these existing works by considering the real-time reserve activation, mimicking the outcome of intraday and balancing markets. Gebrekiros et al. (2013, 2014, 2014b, 2015) do not consider this activation step. Real-time balancing actions are considered by Farahmand and Doorman (2011, 2012), but are limited to minimizing the deviation from the day-ahead schedule rather than re-optimizing the dispatch in order to minimize the operating cost, as proposed in this work.

Three different approaches to include network constraints in cross-border reserve procurement can be found in the literature. The first approach is stochastic reserve procurement. Various possible real-time scenarios and their respective probabilities are considered when optimally procuring reserves. As such, the probability that reserves are being activated (which can be mathematically represented by a set of post-contingency scenarios) and the impact of this activation on cross-border exchanges is taken into account when procuring these reserves (Chen et al., 2014; Bruninx et al., 2016). A second approach is dynamic reserve zones. Depending on the forecasted system state, control areas can be merged into one reserve zone with common reserve procurement. As the system state changes over time, the reserve zone configuration should change over time as well (Wang and Hedman, 2015; Lyon et al. 2015). According to a third approach, a heuristic-based constraint is added to the reserve procurement problem. This additional constraint allocates part of the cross-border capacity to the reserve markets (Zani et al., 2016; Gebrekiros et al., 2013; Gebrekiros et al., 2015). For instance, 30% of the cross-border capacity can be allocated to the procurement (and activation) of reserves (Zani et al., 2016). In this paper, the latter approach is applied. Novel and improved heuristic-based constraints for the reserve procurement phase are proposed and evaluated.

III. MODEL FORMULATION AND SCENARIOS

A dedicated generation scheduling model is developed for this study, representing the European electricity market design. The scheduling model sequentially optimizes the day-ahead energy market, the day-ahead procurement of reserves and the real-time activation of reserves. Note that the reserve dimensioning problem is assumed to be solved before the day-ahead energy market starts (i.e., the dimensioning of reserves is not considered in this paper).

Figure 1 gives a schematic overview of the model setup and the considered scenarios. The day-ahead energy market is the same for every considered scenario. In the reserve procurement phase, three different approaches are considered: (1) uncoordinated reserve procurement, (2) coordinated reserve procurement and (3) coordinated reserve procurement with network constraints. In the real-time activation phase, two different approaches are considered: (1) uncoordinated reserve activation and (2) coordinated reserve activation. In an uncoordinated scenario, a TSO procures or activates only reserves in its own control area. In contrast, cross-border procurement or activation is possible in a coordinated scenario. Coordination in the procurement phase must be followed by coordination in the activation phase (it would be meaningless to procure cross-border reserves without being able to activate them). This results in four different scenarios considered in this paper:

- Scenario A: uncoordinated procurement and uncoordinated activation;
- Scenario B: uncoordinated procurement and coordinated activation;
- Scenario C: coordinated procurement and coordinated activation;
- Scenario D: coordinated procurement with network constraints and coordinated activation.

Figure 1. Schematic overview of the model setup and the considered scenarios.

The scheduling model is formulated as a mixed-integer linear program in GAMS 24.4 and solved using the CPLEX 12.6 solver with a stopping tolerance of 0.1%. A nomenclature is provided in Appendix.

a. Day-ahead energy market

The day-ahead energy market is modeled by means of a unit commitment model, with an hourly temporal resolution. The objective function of the unit commitment model is the minimization of the total operating

system cost, consisting of generation costs (for fuel, variable operations and maintenance, and CO₂ emissions) and start-up costs.

$$\min \sum_i \sum_t C_i z_{i,t} + MC_i g_{i,t} + SUC_i v_{i,t} \quad (1)$$

The optimization problem is subject to the market clearing condition (Eq. 2)⁷, power plant generation limits (Eq. 3)⁸, minimum up and down times (Eqs. 4-5), the binary relation (Eq. 6), trade-based network equations corresponding to the Net Transfer Capacity (NTC) market coupling (Eqs. 7-8)⁹, binary constraints (Eq. 9) and non-negative constraints (Eq. 10). Note that a day-ahead forecast of the load ($DEM_{n,t}$) and generation from renewable energy sources ($RES_{n,t}$) is used to clear the day-ahead energy market.

$$\sum_i AI_{n,i} (z_{i,t} \underline{P}_i + g_{i,t}) + RES_{n,t} = DEM_{n,t} + p_{n,t} \quad \forall n, \forall t \quad (2)$$

$$0 \leq g_{i,t} - rs_{i,t}^- \leq g_{i,t} + rs_{i,t}^+ \leq (\bar{P}_i - \underline{P}_i) z_{i,t} \quad \forall i, \forall t \quad (3)$$

$$z_{i,t} \geq \sum_{t'=t+1-MUT_i}^t v_{i,t'} \quad \forall i, \forall t \quad (4)$$

$$1 - z_{i,t} \geq \sum_{t'=t+1-MDT_i}^t w_{i,t'} \quad \forall i, \forall t \quad (5)$$

$$z_{i,t-1} - z_{i,t} + v_{i,t} - w_{i,t} = 0 \quad \forall i, \forall t \quad (6)$$

$$p_{n,t} = \sum_l AI_{n,l} f_{l,t} \quad \forall n, \forall t \quad (7)$$

$$\overline{F^{min}}_l \leq f_{l,t} \leq \overline{F^{max}}_l \quad \forall l, \forall t \quad (8)$$

$$v_{i,t}, w_{i,t}, z_{i,t} \in \{0,1\} \quad \forall i, \forall t \quad (9)$$

$$g_{i,t}, rs_{i,t}^-, rs_{i,t}^+ \geq 0 \quad \forall i, \forall t \quad (10)$$

b. Day-ahead reserve procurement

After the day-ahead energy market is cleared, the procurement of reserves takes place. The day-ahead procurement phase determines on an hourly basis which generation units provide reserves in order to meet the reserve requirements. The same unit commitment model is used for the day-ahead reserve procurement and the day-ahead energy market clearing, with two differences: (1) a spinning and non-spinning reserve constraint is added to the unit commitment model (see below) and (2) the day-ahead unit commitment decision of nuclear and lignite-fired units is set fixed (Eq. 11).

$$z_{i,t}^{DA} = z_{i,t}^{RP} \quad \forall i \in I^{nuc, lign}, \forall t \quad (11)$$

Two types of reserves are included in the procurement model: spinning reserves and non-spinning reserves. Spinning reserves are reserves delivered by online power plants, corresponding to aFRR. Non-

⁷ The parameter $AI_{n,i}$ links power plants to nodes: $AI_{n,i} = 1$ if power plant i is connected to node n , $AI_{n,i} = 0$ otherwise.

⁸ No reserve constraints are imposed to the day-ahead market and as such, $rs_{i,t}$ are zero ($rs_{i,t}$ are allowed to become non-zero in the reserve procurement phase).

⁹ A trade-based network representation is used in this paper, corresponding to the net transfer capacity (NTC) market coupling. The NTC approach is preferred here to the flow-based market coupling (FBMC) approach due to its simplicity and transparent network capacity. The FBMC can be easily implemented in the model, but it is currently still difficult to obtain proper data on flow-based network parameters such as power transfer distribution factors (PTDF) and remaining available margins (RAM).

spinning reserves are reserves delivered by offline power plants that can quickly start-up, corresponding to mFRR and RR. Spinning reserves (upward and downward) can be delivered by coal-fired units, gas-fired units (i.e., combined-cycle gas turbines and open-cycle gas turbines) and oil-fired units (i.e., internal combustion engines). Non-spinning reserves (upward) can be delivered by open-cycle gas turbines and oil-fired units. Reserves delivered by load curtailment (e.g., interruptible loads) are not included explicitly in the simulation model, but their historical contribution to upward non-spinning reserves is deducted from the non-spinning reserve requirement.¹⁰ Renewable generation units and storage units are assumed not to participate in the reserve market.¹¹

Different reserve requirements can be imposed. The remainder of this subsection lists three possible procurement approaches.

1) Approach 1: uncoordinated procurement

A first reserve rule is based on uncoordinated procurement, meaning that every TSO is responsible for meeting its reserve requirement with reserves within its control area. Each control area is represented by one node. This translates into the following spinning reserve requirement for upward and downward reserves, respectively (Eqs. 12-13), and upward non-spinning reserves (Eqs. 14-15). The full reserve procurement model consists of Eqs. (1-15).

$$\sum_{i \in I^s} A_{n,i} r s_{i,t}^+ \geq R_n^{s,+} \quad \forall n, \forall t \quad (12)$$

$$\sum_{i \in I^s} A_{n,i} r s_{i,t}^- \geq R_n^{s,-} \quad \forall n, \forall t \quad (13)$$

$$\sum_{i \in I^s} A_{n,i} r s_{i,t}^+ + \sum_{i \in I^{ns}} z_{i,t}^{ns} \bar{P}_i \geq R_n^{s,+} + R_n^{ns,+} \quad \forall n, \forall t \quad (14)$$

$$z_{i,t}^{ns} \leq 1 - z_{i,t} \quad \forall i \in I^{ns}, \forall t \quad (15)$$

This is a conservative procurement approach with a strong emphasis on reliability and less on cost efficiency. Since reserves are always scheduled in the control area where they are needed, cross-border grid constraints will not constrain the activation of reserves. However, cost-effective spatial arbitrage possibilities might be neglected. This reserve procurement rule implicitly assumes that no cross-border capacity is available in real-time. Furthermore, in an uncoordinated procurement scenario, the day-ahead energy balance of each control area must remain the same in the reserve procurement phase:

$$f_{l,t}^{DA} = f_{l,t}^{RP} \quad \forall l, \forall t \quad (16)$$

2) Approach 2: coordinated procurement

A second reserve rule is based on coordinated procurement, meaning that control areas can procure reserves in any control area, without considering grid constraints. The spinning reserve requirements for upward and downward reserves, respectively (Eqs. 17-18), and upward non-spinning reserves

¹⁰ For instance, with an upward non-spinning reserve of 100 MW and 20 MW of upward reserves delivered by interruptible loads, the effective upward non-spinning reserve requirement imposed to the model becomes 80 MW.

¹¹ FCR are not considered in this model, given that the FCR time frame (i.e., seconds to minute) is too small to be captured in a unit commitment model with hourly or quarter-hourly time resolution.

requirement become (Eqs. 19-20). The full reserve procurement model consists then of Eqs. (1-11) and Eqs. (17-20).

$$\sum_{i \in I^s} rs_{i,t}^+ \geq \sum_n R_n^{S,+} \quad \forall t \quad (17)$$

$$\sum_{i \in I^s} rs_{i,t}^- \geq \sum_n R_n^{S,-} \quad \forall t \quad (18)$$

$$\sum_{i \in I^s} AI_{n,i} rs_{i,t}^+ + \sum_{i \in I^{ns}} z_{i,t}^{ns} \bar{P}_i \geq \sum_n R_n^{S,+} + R_n^{ns,+} \quad \forall t \quad (19)$$

$$z_{i,t}^{ns} \leq 1 - z_{i,t} \quad \forall i \in I^{ns}, \forall t \quad (20)$$

This is a very optimistic procurement strategy with a strong emphasis on cost efficiency and less on reliability, and could therefore be considered as a theoretical extreme. The real-life applicability of such a coordinated reserve procurement rule may be the subject of future research. Reserves can be scheduled in any control area with cheap reserves, but with no guarantee that these reserves can be actually dispatched to maintain the real-time system balance in another control area. This reserve procurement rule implicitly assumes that unlimited cross-border capacity is available for reserve activation in real-time.

3) Approach 3: coordinated procurement with network constraints

The third reserve rule takes network constraints into account in the reserve procurement. This reserve procurement approach is one of the main contributions of this paper. It is imposed on the model that the transmission network has to be able to facilitate the additional flows resulting from the activation of the difference between scheduled and required reserves in a control area. The reserve requirement for upward spinning reserves becomes:

$$\sum_{i \in I^s} rs_{i,t}^+ \geq \sum_n R_n^{S,+} \quad \forall t \quad (21)$$

$$\sum_{i \in I^s} AI_{n,i} rs_{i,t}^+ - R_n^{S,+} = \sum_l A_{l,n} \Delta^+ f_{l,t} \quad \forall n, \forall t \quad (22)$$

$$\overline{F^{min}}_l \leq f_{l,t} + \Delta^+ f_{l,t} \leq \overline{F^{max}}_l \quad \forall l, \forall t \quad (23)$$

The reserve requirement for downward spinning reserves becomes:

$$\sum_{i \in I^s} rs_{i,t}^- \geq \sum_n R_n^{S,-} \quad \forall t \quad (24)$$

$$R_n^{S,-} - \sum_{i \in I^s} AI_{n,i} rs_{i,t}^- = \sum_l A_{l,n} \Delta^- f_{l,t} \quad \forall n, \forall t \quad (25)$$

$$\overline{F^{min}}_l \leq f_{l,t} + \Delta^- f_{l,t} \leq \overline{F^{max}}_l \quad \forall l, \forall t \quad (26)$$

The reserve requirement for upward non-spinning reserves remains the same as in the first approach (Eqs. 14-15). The full reserve procurement model consists then of Eqs. (1-11), Eqs. (14-15) and Eqs. (21-22).

This reserve procurement rule considers two additional network situations, i.e., the simultaneous activation of all upward spinning reserves and the simultaneous activation of all downward spinning reserves at every node. However, it is not guaranteed that these situations are the *worst possible situations* for the network, and hence system infeasibilities can still occur in the real-time phase. It is also not sure whether this heuristic-based rule leads to the optimal market outcome. Although, it is likely that this last approach performs better—in terms of system costs and reliability—than the other two approaches (which we will illustrate in a case study in section V.)

c. Real-time reserve activation

After the day-ahead energy market and the day-ahead reserve procurement have been solved, reserves can be activated to deal with real-time imbalances. Again, the same unit commitment formulation is used as in the day-ahead energy market for the real-time activation phase (Eqs. 1-10), with three differences: (1) the load and RES-based generation time series is adjusted to include real-time imbalances caused by forecast errors and contingencies, (2) the time step is adjusted to a quarter-hour instead of the hourly time step in the day-ahead energy market and reserve procurement, (3) the day-ahead power output of the nuclear units and lignite-fired units is fixed—indicating that these units cannot deliver reserves—and the unit commitment decisions for coal-fired power plants and combined-cycle gas fired power plants are fixed—indicating that these units can only deliver spinning reserves. Note that the activation of reserves is not limited to the day-ahead procured reserves, e.g., flexible units, capable of starting up on short notice, may be activated to provide upward reserves even if they're not scheduled as non-spinning reserve.

The activation of reserves in real-time can be coordinated, meaning that control areas can change their day-ahead energy balance and import or export flexible generation in real-time if cross-border capacity is available. Next to coordinated, also uncoordinated reserve activation is considered, which requires that import/export balance of each control area does not change in real-time:

$$f_{l,t}^{DA} = f_{l,t}^{RP} = f_{l,t}^{RT} \quad \forall l, \forall t \quad (27)$$

Every model (day-ahead energy market, day-ahead reserve procurement and real-time reserve activation) is solved for a full year, in daily blocks with an overlap of half a day. Consecutive daily blocks are linked by means of sequential boundary conditions (i.e., the system state at the end of day D is the starting condition for day D+1).

d. Model assumptions

First, the European electricity market, which is a mix of bilateral trading and power exchanges with (simplified) bidding, does not fully correspond to a unit commitment model. However, the generation schedule obtained from a unit commitment model is a good approximation of the European market outcome, assuming a perfectly competitive market. Second, only two snap-shots are considered, i.e., day-ahead and real-time. In reality, an intra-day market is organized between day-ahead and real-time in which generators can adapt their day-ahead position in response to continuously updated system information (e.g., updated renewable generation forecasts). However, the model allows flexible generation units to start-up and shut-down in the real-time phase, hereby giving more flexibility to the real-time phase than strictly available in real-time. Therefore, neglecting the intra-day market has a limited impact on the presented results. Third, the reserve procurement market—as modeled in this paper—takes places after the day-ahead market, with short-term contracts (hourly contracts). In reality, current European reserve markets consist of longer-term contracts (weekly, monthly or yearly) between transmission system operators and reserve providers. Reserve providers schedule—on a daily basis and after the day-ahead market—their units in order to comply with their reserve contracts and the day-ahead market outcome. As such, the reserve procurement phase modelled in this paper corresponds to the daily scheduling of units by reserve providers. As long-term reserve contracts are not explicitly modelled in this paper, the liquidity in the reserve market is overestimated. Finally, the real-time activation phase is implemented as

a one-shot optimization with perfect information on imbalances during the considered day. This implies that the impact of dynamic constraints such as minimum up and down times is underestimated.

IV. CASE STUDY

The 2013 Central Western European (CWE) electricity system is considered as case study. The CWE area covers Belgium, Luxembourg, France, Germany and the Netherlands. Luxembourg is considered to be part of the Belgian system and each country is assumed to be one control area¹². Time series for a full year are considered.

The aggregated annual electricity consumption is 1,214 TWh, with a peak load of 189 GW (ENTSO-E, 2015a).¹³ Annual consumption is higher in France (42%) and Germany (40%) than in Belgium (8%) and the Netherlands (10%).

The conventional generation portfolio consists of 625 units with an aggregated generation capacity of 177 GW (Platts, 2015).¹⁴ Table I gives an overview of the installed conventional generation capacity per country and per generation type. Power plant characteristics are taken from ENTSO-E (2015b) and shown in Table II. Different rated efficiencies are allocated to power plants based on their commissioning year. Average 2013 fuel and CO₂ emission prices are used.¹⁵

Historical generation time series for (small) cogeneration units and renewables are imposed as an exogenous input to the model, since these generation units are (mainly) non-dispatchable from an electricity market perspective (i.e., the generation of these sources is not driven by an electricity price signal but by other factors such as heat demand or meteorological conditions)¹⁶. Generation data from conventional hydro (i.e., run-of-river units and water dams), bio-energy units (including cogeneration) and fossil-fuel cogeneration units are taken from ENTSO-E (2015a). Wind and solar generation profiles for Belgium, France and Germany originate from the Belgian TSO (Elia, 2015), the French TSO (RTE, 2015a) and the German TSOs (EEX, 2015), respectively. The wind and solar generation profiles for the Netherlands are obtained by rescaling the Belgian profile. The share of renewable generation in the annual CWE consumption is 19%, varying from 11% in Belgium and the Netherlands to 28% in Germany.

The Net Transfer Capacities (NTC) for February 2015 are used as transmission capacity between the different countries in the trade-based network model (ENTSO-E, 2015c). Table III gives an overview of the NTC-values in the case study.

¹² Germany forms a single market zone together with Austria, but is in this study considered as a separate market zone. Germany has four TSOs, each responsible for part of the high voltage grid. Germany is considered as one control area in this paper.

¹³ The actual electricity consumption (1,161 TWh/a) is corrected for net export to neighboring countries outside the CWE region (48 TWh/a) and net consumption of pumped storage units (5 TWh/a).

¹⁴ Large cogeneration units (i.e., with an electric power output larger than 400 MW) are considered as dispatchable in the electricity market and hence included in the conventional generation portfolio).

¹⁵ The following fuel prices are used: 10 EUR/MWh_{th} for coal, 27 EUR/MWh_{th} for natural gas, 55 EUR/MWh_{th} for light fuel oil, 50 EUR/MWh_{th} for heavy fuel oil. A fuel price of 2.3 EUR/MWh_{th} for uranium and 5 EUR/MWh_{th} for lignite is assumed. A CO₂ emission cost of 5 EUR/tCO₂ is used.

¹⁶ The cogeneration power plants in the model are small distributed units (the large cogeneration power plants are modeled as fully dispatchable power plants) and as such difficult and assumed not to participate to include in the reserve market. Allowing these small units to participate in the reserve market could, depending on their operating costs and the flexibility they may offer, increase the availability of flexibility in each control area and lower the need for cross-border reserve exchanges.

The model outcome is compared with historical observed generation (i.e., simulation results obtained with the day-ahead energy model) (ENTSO-E, 2015a). The capacity of the nuclear units is derated in order to match simulated and historical nuclear generation.

The spinning reserve requirement imposed in the day-ahead reserve procurement phase corresponds to the aFRR requirements (50Hertz, 2014; RTE, 2015b). The spinning reserve requirement is symmetric, meaning that the same amount of reserves is required in the upward and downward direction. The non-spinning reserve requirement, corresponding to the mFRR and RR requirements, are only defined for upward reserves. Table IV gives an overview of the reserve requirements.¹⁷

In the real-time phase, 2013 historical real-time imbalances are imposed to the load. Real-time imbalances originate from the respective TSOs (Elia, 2015; Tennet, 2015; Amprion, 2015; RTE, 2015b). A positive imbalance corresponds to a surplus of electrical energy in the system (i.e., represented by a reduction in load) and a negative imbalance corresponds to a deficit of energy (i.e., represented by an increase in load). Figure 2 shows the probability density function of the 2013 historical imbalances for the different countries. The annual aggregated imbalance in the considered countries was 2.3 TWh. Note that the imbalance data has a quarter-hourly time resolution, implying that instantaneous imbalances are averaged out over every quarter-hour.

[GW]	Belgium	France	Germany	Netherlands
Nuclear units	4.5	57.9	10.7	0.3
Steam-cycle units	0.9	10.5	47.8	4.7
Combined-cycle gas turbines	4.4	5.5	12.3	10.9
Open-cycle gas turbines	0.8	1.9	3.2	0.6
Internal combustion units	-	0.3	0.0	-

Table I. Overview of installed conventional generation capacity per control area (market zone) and generation type.

	Efficiency [%]	$\frac{P}{\overline{P}}$ [% $\overline{P}$]	MUT,MDT [h]	Var. O&M [EUR/MWh]
Nuclear units	33	50	12	9.0
Steam-cycle units	35/40/45	43	6/12	3.3
Combined-cycle gas turbines	40/48/58	35	3	1.6
Open-cycle gas turbines	35/42	30	1	1.6
Internal combustion units	35/40	30	1	3.3

Table II. Overview of technical characteristics per generation type (Var. O&M: variable operations and maintenance costs). Different efficiencies are used depending on the commission year of the power plant. Lignite-fired steam-cycle units have larger MUT and MDT than coal-fired steam-cycle units.

¹⁷ Germany has higher reserve constraints than France, partly driven by higher renewable shares in Germany.

To / From	Belgium	France	Germany	Netherlands
Belgium	-	2200		1300
France	1600	-	2800	
Germany		1800	-	2500
Netherlands	1500		2600	-

Table III. Overview of net transfer capacities between the different countries (in MW), as used in the case study.

	Belgium	France	Germany	Netherlands
Spinning reserves	140	650	2000	300
Non-spinning reserves	350 ¹⁸	1850	2500	350

Table IV. Overview of reserve requirements per country (in MW). Spinning reserves are symmetric and correspond to aFRR. Non-spinning reserves are only defined for upward reserves and correspond to mFRR and RR.

Figure 2. Probability density functions of the 2013 imbalances in the different countries (discretization intervals of 50 MW are used for Belgium and Netherlands, and 200 MW for Germany and the Netherlands).

¹⁸ Besides the 350 MW mFRR supplied by generation units, Elia contracts 50 MW Dynamic Profile mFRR and 261 MW interruptible load (all upward reserves).

V. RESULTS

This section presents and discusses the simulation results from the unit commitment model. The generation costs, system reliability, generation and reserve scheduling, and the utilization of transmission capacity are analyzed and discussed for the four different scenarios considered in this paper (see section III and Figure 1).

a. Generation costs and system reliability

For every scenario, the operating generation costs and the generation scheduling is determined for the day-ahead energy market, the day-ahead reserve procurement and the real-time activation phase.

- The day-ahead market outcome is the same for every scenario. The total annual operating generation cost in the day-ahead energy market is 17,680 Mio EUR (see Table V).
- In the day-ahead reserve procurement, the day-ahead energy generation scheduling is adjusted in order to meet the reserve requirements. First, Table V shows that the annual operating costs are higher in the reserve procurement phase than in the day-ahead market, regardless of the scenario. This cost increase is caused by the reserve requirements, which push flexible but more expensive generation units online to deliver spinning reserves. Second, one can see from Table V that operating costs decrease in the day-ahead reserve procurement with increasing level of coordination in the procurement phase. Generation costs decrease with 2.3% when an uncoordinated procurement of reserves (scenarios A and B) is replaced by a fully coordinated procurement of reserves (scenario C). If network constraints are taken into account in the procurement of reserves (scenario D), overall operating generation costs decrease with 0.6% compared to uncoordinated reserve procurement.
- In the real-time reserve activation phase, the different reserve procurement rules can be evaluated in terms of cost-efficiency and system reliability. Table V shows the generation costs (as an indicator of cost efficiency) and the loss of load volume (as an indicator of system reliability).¹⁹ Note that reliability in this analysis refers to the availability of the procured reserves, i.e. the operational security of a power system, and should not be confused with the broader concept of power systems reliability (Luickx, 2009). Generation costs decrease with an increasing level of coordination, with scenario C resulting in the lowest operating generation cost. However, scenario C is also the only scenario with loss of load (i.e., 1.3 GWh/a load shedding). Loss of load occurs when too little upward reserves are available to deal with real-time system imbalances. As no transmission constraints are taken into account in the reserve procurement in scenario C, not all cross-border scheduled upward reserves can be used in real-time, resulting in loss of load. Scenario D results in the lowest operating generation cost without causing loss of load.

Also the amount of real-time wind curtailment is shown in Table V, expressed as a percentage of the available wind generation. Wind curtailment is only possible at very high costs (i.e., 10,000 €/MWh, this cost is not included in reported generation costs) and as such occurs when too little downward reserves

¹⁹ Load curtailment is corrected for load shedding by interruptible consumers who provide reserves. Only the hours with load shedding higher than the maximum load shedding in scenario A are considered as “real” loss of load hours. The maximum load shedding per country in scenario A is 310 MW for Belgium, 1280 MW for France, 930 MW for Germany and 180 MW for the Netherlands.

are available. In this respect, wind curtailment can be interpreted in this analysis as a metric for system flexibility.²⁰ Again, scenario C indicates the highest wind curtailment since not all cross-border scheduled downward reserves can be activated in real-time. Scenarios B and D show the lowest amount of wind curtailment, indicating a high level of system flexibility.

The cost-efficiency and system reliability—and the trade-off that exists between both metrics—resulting from the different procurement rules are summarized on Figure 3. Cost-efficiency is expressed as annual operating generation costs (i.e., lower generation costs indicate higher cost efficiency) and system reliability as loss of load and wind curtailment (i.e., lower loss of load and wind curtailment indicate higher system reliability and flexibility). Note that the amount of wind curtailment dominates the amount of loss of load in this considered case study. Figure 3 shows that both cost-efficiency and system reliability improve when going from scenario A, over scenario B, to scenario D. Scenario D is hence more optimal than scenarios A and B. Scenario C is more cost-efficient but less reliable than scenario D. Depending on the relative importance of cost-efficiency with respect to system reliability, scenario C is preferable to scenario D or vice versa. However, as discussed above, scenario C is a theoretical extreme.

	Scenario A	Scenario B	Scenario C	Scenario D
DA generation cost [Mio EUR/a]	17,680	17,680	17,680	17,680
RP generation cost [Mio EUR/a]	18,315	18,315	17,895	18,202
relative to scenario A		0.0%	-2.3%	-0.6%
RT generation cost [Mio EUR/a]	18,341	18,253	17,952	18,148
relative to scenario A		-0.5%	-2.1%	-1.1%
RT loss of load hours [GWh/a]	0	0	1.3	0
RT wind curtailment [%wind]	1.3%	0.9%	5.1%	0.9%

Table V. Overview of operating generation costs and system reliability indicators for the different scenarios and different phases (DA: day-ahead energy market, RP: day-ahead reserve procurement, RT: real-time reserve activation). Generation costs include production costs and start-up costs (loss of load costs and renewables curtailment costs are not included).

²⁰ A high wind curtailment cost has been imposed to ensure downward reserves are scheduled, as this paper focusses on reserves delivered by conventional power plants. This high curtailment cost should not be interpreted as priority dispatch for wind.

Figure 3. Operating generation costs (as a metric for cost efficiency) and annual loss of load and wind curtailment (as a metric for system reliability) for the different scenarios.

b. Generation and reserve scheduling

This section takes a closer look at the generation schedules and how they change under the different procurement rules. Table VI gives an overview of the day-ahead generation on an annual basis. France and Germany export electrical energy to Belgium and the Netherlands.

In the day-ahead reserve procurement phase, the day-ahead energy market schedule is adjusted to meet the reserve requirements. Depending on the considered procurement rule, reserves can be scheduled in different control areas. Figure 4 shows how the procurement of spinning reserves shifts between control areas depending on the reserve procurement rule. In an uncoordinated procurement scenario (scenarios A and B), each control area provides its own reserve requirement. In a fully coordinated procurement scenario (scenario C), reserve procurement shifts from Germany and France to the Netherlands (and to a lesser extent Belgium). Germany and France have less flexible conventional generation capacity available, relative to the need for reserves, than the Netherlands and Belgium (see Table IV). If network constraints are taken into account in the procurement of reserves (scenario C), reserve procurement shifts again from Germany and France to the Netherlands and Belgium, however somewhat differently: less upward spinning reserves are shifted to Belgium and less downward reserves are shifted to the Netherlands.

In short, reserve procurement shifts—for the considered case study—from France and Germany towards the Netherlands. The impact of this shift on TSOs costs and reserve provider revenues depends on the reserve market design (e.g., pay-as-bid versus pay-as-clear), but in general one can conclude that TSOs in France and Germany will experience a decrease in reserve costs. At the same time, some reserve providers in France and Germany will no longer sell reserves to the French and German TSOs while reserve providers in the Netherlands will sell more reserves.

[TWh/a]	Belgium	France	Germany	Netherlands
Nuclear units	39.8	441.8	93.0	2.5
Coal and lignite-fired units	4.2	11.8	192.5	34.1
Gas and oil-fired units	10.3	5.1	0.3	25.2
Renewables	19.4	86.3	214.3	33.6
Total generation	73.7	545	500.1	95.4
Import	18.4	-21.7	-17.7	20.9
Load	92.1	523.3	482.5	116.4

Table VI. Overview of generation output of the day-ahead energy market.

a. Upward spinning reserves

b. Downward spinning reserves

Figure 4. Overview of the average procurement of spinning reserves in the different countries under the different scenarios (BE: Belgium, FR: France, DE: Germany, NL: Netherlands).

c. Utilization of transmission capacity

Three different reserve procurement rules are studied. Scenarios A and B are based on a very conservative procurement rule, assuming that no cross-border transmission capacity can be used in reserve markets (i.e., uncoordinated procurement). Scenario C is based on a very optimistic procurement rule, assuming that infinite transmission capacity can be used in reserve markets (i.e., fully coordinated procurement). Scenario D is based on a more moderate procurement rule, considering worst-case activation scenario, i.e., the activation of all upward or downward spinning reserves in all control areas (i.e., coordinated procurement with network constraints).

Figure 4 shows that reserves are procured—if cross-border reserve procurement is allowed—in countries with a large presence of flexible generation capacity relative to the need for reserves in that control area. The procurement of cross-border reserves in scenario D is limited by the remaining cross-border transmission capacity, unlike scenario C. Therefore, in scenario D, upward reserves are scheduled in countries with large relative share of flexible generation capacity which are at the same time net importers—to make sure that enough export capacity is still available. In this particular case study, the countries with a large share of flexible but expensive generation capacity (i.e., Belgium and the

Netherlands) are also net importers of electrical energy. As a result, the difference in reserve procurement between scenarios C and D is limited. However, this result depends heavily on the assumptions made regarding flexibility of generation plants. If spinning reserves can only be delivered by more expensive units (e.g., gas-fired units), countries with a lot of this expensive generation will attract spinning reserves but will also be likely net importers. On the contrary, if cheaper generation units can deliver reserves as well (e.g., nuclear units), the countries that will attract reserves are more likely to be net exporters. In the latter case, the importance of network constraints in cross-border reserve procurement increases. This reasoning is valid for power systems where marginal generation costs increase with the flexibility of the associated plant. If cheaper power plants are more flexible than more expensive power plants, this reasoning does not longer hold.

This is further illustrated by Figure 5, which shows the duration curve of the reserve export margin for Germany. The reserve export margin is the difference between the remaining export capacity of a control area and the possible export of spinning reserves. The remaining export capacity of a country is calculated as the cross-border export capacity minus the cross-border export flows from the day-ahead energy market (import flows are negative), aggregated over all cross-border lines connected to that country. For instance, a country with an aggregated export capacity of 3.5 GW and a net export of 1 GW during a certain time step in the day-ahead energy market has a remaining export capacity of 2.5 GW during that time step. The possible export of spinning reserves is the difference between the scheduled and required upward spinning reserves within a control area or the difference between the required and scheduled downward reserves in that control area (see Table VII). A negative reserve export margin indicates that not all allocated spinning reserves can be exported, which may lead to infeasibilities in real-time. Figure 5 shows that negative export margins occur in Germany in scenario C, but not in scenario D since transmission constraints were taken into account in the reserve procurement. In other words, the procurement rule in scenario D enforces that procured reserves can be imported or exported.

Similarly, the reserve import margin can be calculated. The reserve import margin is the difference between the remaining import capacity of a control area and the possible import of spinning reserves. The remaining import capacity is calculated as the cross-border import capacity minus the cross-border import flows (export flows are negative), aggregated over all cross-border lines connected to that country. The possible import of spinning reserves is the difference between the required and scheduled upward spinning reserves in a control area or the difference between the scheduled and required downward spinning reserves in that control area (see Table VII). Figure 5 shows the reserve import margins for Germany, leading to the conclusion that no negative export and import margins occur in scenario D. Similar conclusions can be drawn for the other countries.

	Upward reserves	Downward reserves
Export of reserves	$rs^+ > R^+$	$rs^- < R^-$
Import of reserves	$rs^+ < R^+$	$rs^- > R^-$

Table VII. Schematic overview of all possible export/import options of spinning reserves for a control area. A control area can export spinning reserves (upward or downward reserves) or import spinning reserves (upward or downward reserves). R refers to the required reserves in the control area and rs refers to the procured reserves in the control area (all in absolute values).

a. Upward reserves (export margin)

b. Downward reserves (export margin)

c. Upward reserves (import margin)

d. Downward reserves (import margin)

Figure 5. Duration curve of the reserve export and import margins for Germany. A negative export/import margin indicates that the remaining export/import capacity for Germany is smaller than the amount of spinning reserves that has to be exported/imported if all spinning reserves (downwards or upwards) are activated in Germany. The export and import margins become negative in scenario C, but not in scenario D.

VI. CONCLUSIONS AND POLICY RECOMMENDATIONS

This paper studies the impact of cross-border reserve markets on system generation costs and system reliability, for a case study of the Central Western European electricity system. More in particular, the implementation of network constraints in cross-border reserve procurement is analyzed. Based on the presented analysis, two conclusions can be drawn, each linked to a policy recommendation.

First, our analysis shows the benefits of cross-border reserve markets. By allowing TSOs to procure and activate reserves in neighboring control areas, a more cost-efficient and a more secure system can be realized. The underlying driver of these improvements is spatial arbitrage, i.e., reserves can be procured and activated there where they have the lowest cost. The case study indicates a reduction in operating costs of 0.5% to 2.1% when (part of) the reserve market is coordinated between control areas. The magnitude of the efficiency gain links to the ease of implementation. Coordinating solely the reserve activation is easier to implement but result in modest efficiency gains (i.e., 0.5%). In order to achieve higher

efficiency gains (i.e., 2.1%), also reserve procurement needs to be coordinated. This last approach however requires more changes to the current market design and detailed predictions of the available, hourly transmission capacity for the reserve market. Moreover, due to the increase of partly unpredictable generation, the need for reserves will likely increase in each country. This additional reserve need is poorly correlated in space (i.e., a forecast error in one country is not strongly correlated to a forecast country in another country) and as such cross-border reserve markets may gain importance. Policy makers, regulators and power system operators should speed up the ongoing implementation of cross-border reserve markets in Europe to seize these efficiency gains.

Second, it is challenging to properly account for network constraints in cross-border reserve markets. The procurement of reserves happens under uncertainty as neither the system state in real-time (i.e., the remaining cross-border capacity) nor the activation of the procured reserves is known. Therefore, transmission capacity should be reserved for cross-border reserves based on predictions or certain rules. In this paper, we consider three different reserve procurement rules: (1) uncoordinated with zero cross-border transmission capacity for reserve procurement, (2) fully coordinated with infinite cross-border transmission capacity for reserve procurement and (3) coordinated with limited cross-border transmission capacity for reserve procurement. In this latter case, the available cross-border capacity is limited by two worst-case activation scenarios (i.e., the activation of all scheduled upward and downward spinning reserves in all control areas). The third procurement rule performs best for the considered case study, obtaining a reliable system state (i.e., without loss of load) at lowest cost observed in the presented case study. However, it is not sure whether this heuristic-based rule leads to the most cost-efficient market outcome possible. Policy makers should, in close collaboration with regulators and TSOs, design transmission capacity allocation procedures for reserve markets that allow capturing the cost-efficiency gains, without jeopardizing system reliability. The reserve rules analyzed in this paper can serve as inspiration for a robust capacity allocation procedure.

APPENDIX – NOMENCLATURE

The superscript *DA* refers to day-ahead energy markets, *RP* to day-ahead reserve procurement and *RT* to real-time reserve activation.

Sets

I (index i)	set of all power plants
I^s	subset of power plants which can deliver spinning reserves
I^{ns}	subset of power plants which can deliver non-spinning reserves
L (index l)	set of transmission lines
N (index n)	set of nodes
T (index t)	set of time steps

Parameters

$A_{l,n}$	network incidence matrix, $A_{l,n} \in \{0,1\}$
$AI_{n,i}$	matrix linking power plant i to node n , $AI_{n,i} \in \{0,1\}$
C_i	generation cost of power plant i at minimum power output [EUR/h]
$DEM_{n,t}$	load at node n at time step t [MW]
$\overline{F^{\min}_l}, \overline{F^{\max}_l}$	minimum and maximum power flow through line l [MW]
$\overline{P_i}$	maximum power output of power plant i [MW]
$\underline{P_i}$	minimum power output of power plant i [MW]
$RES_{n,t}$	renewable generation at node n at time step t [MW]
$R_n^{ns,+}$	upward non-spinning reserve requirement at node n [MW]
$R_n^{s,+}$	upward spinning reserve requirement at node n [MW]
$R_n^{s,-}$	downward spinning reserve requirement at node n [MW]
MC_i	marginal generation cost of power plant i [EUR/MWh]
MDT_i	minimum down time of power plant i [h]
MUT_i	minimum up time of power plant i [h]
SUC_i	start-up cost of power plant i [EUR/start]

Variables

$\Delta^+ f_{l,t}, \Delta^- f_{l,t}$	flow through line l due to reserve activation at time step t [MW]
$p_{n,t}$	network injection at node n at time step t [MW]
$f_{l,t}$	flow through line l at time step t [MW]
$g_{i,t}$	power output above minimum output of power plant i at time step t [MW]
$rs_{i,t}^+$	upward spinning reserve provided by power plant i at time step t [MW]

$rs_{i,t}^-$	downward spinning reserve provided by power plant i at time step t [MW]
$v_{i,t}$	start-up-state of power plant i at time step t , $v_{i,t} \in \{0,1\}$
$w_{i,t}$	shut-down-state of power plant i at time step t , $w_{i,t} \in \{0,1\}$
$z_{i,t}$	on/off-state of power plant i at time step t , $z_{i,t} \in \{0,1\}$
$z_{i,t}^{ns}$	non-spinning delivery state of power plant i at time step t , $z_{i,t}^{ns} \in \{0,1\}$

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