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Abstract

The role of DSOs is evolving due to the increasing penetration of intermittent and distributed energy resources in the distribution system. On the one hand, TSOs are accessing flexibility resources connected to the distribution grid. On the other hand, DSOs are actively managing distribution grid congestion, moving away from the conventional fit and forget approach. As a result, the need for DSO-TSO cooperation has become increasingly important. In this study, we first discuss market and grid operation issues related to different system states and the corresponding congestion management approaches. Second, we discuss possible solutions that are inspired by inter-TSO cooperation solutions as well as solutions that are being adopted by DSOs. Our findings show that the issues are rather similar both at transmission and distribution level; however, the need for cooperation and the solutions will depend on where structural congestion will occur and which borders will be managed.

Keywords

DSO-TSO cooperation, congestion management, distribution grid, network codes, role of DSOs, European electricity grid regulation.

1. Introduction*

The increasing penetration of intermittent generation and distributed energy resources has led to two important developments in power grid operation which in turn has increased the need for cooperation between distribution system operators (DSOs) and transmission system operators (TSOs). The first and widely evident development is that TSOs have started procuring flexibility services for system balancing not only from their neighbouring transmission grids but also from distribution grids. Since the same flexibility resources could also be potentially used for congestion management and voltage control by the DSO, conflicts might arise (EDSO et al. 2015). Consequently, DSOs are concerned about possible misalignment of their actions with TSOs and market players while TSOs are concerned about their ability to perform an efficient balancing of the overall system (CEDEC et al. 2016).

The second development is that DSOs have started to actively manage congestion in their grids, moving away from the conventional fit and forget approach (Eurelectric 2013; Ruester et al. 2014; Anaya and Pollitt 2017; Klinge Jacobsen and Schröder 2012). In some countries, DSOs have been facing massive connection requests. In Ireland and Scotland, this was the case for wind farms whereas in Germany and Italy, it happened for photovoltaic systems. In response to this, some DSOs have introduced smarter ways to connect and release more distributed generation (Kane and Ault 2014). Some others have started considering procurement of flexibility services to redispatch the system at the distribution level. Even though in many countries there are no rules in place that allow DSOs to do so, the Clean Energy Package presents clear provisions that will enable DSOs to procure flexibility services (EC 2016b). This is expected to further increase the need for DSO-TSO cooperation.

To improve DSO-TSO cooperation, DSOs have been proposing solutions; for example, the 'traffic light' concept that signals the distribution grid state to the market has been proposed in Germany (Smart Grid Task Force 2015). Many demonstration projects across Europe have also proposed technical tools to enhance DSO-TSO cooperation; for example, the EVOLVDSO project introduced the interval constrained power flow and sequential optimal power flow tools (Sumaili et al. 2016); while the SMARTNET project has been studying potential DSO-TSO cooperation schemes (Gerard et al. 2017). Moreover, the Council of European Energy Regulators (CEER) has put forward principles that should set the trajectory of the future DSO-TSO relationship and related regulatory arrangements in the areas of governance, network planning and system operation (CEER 2016).

In parallel to these developments, TSOs are also introducing solutions to ensure seamless cooperation among themselves which could help unlock flexibility resources connected to any part of the European power grid and efficiently manage grid constraints. These solutions have been recently entered into force through the European electricity network codes; namely, the Capacity Allocation and Congestion Management (CACM), Forward Capacity Allocation (FCA), Electricity System Balancing Guideline (EBGL), and System Operations Guideline (SOGL).

In light of this context, the contribution of this paper is twofold. First, we provide an overview of the issues by reviewing congestion management approaches in different system states, inspired by the traffic light concept. Second, we discuss possible solutions while considering that solutions at distribution level should recognize the differences in the physical network characteristics, capabilities and complexities of the distribution and transmission systems. DSOs themselves have already been experimenting with solutions, and the cooperation between TSOs can also be an inspiration for future DSO-TSO cooperation.

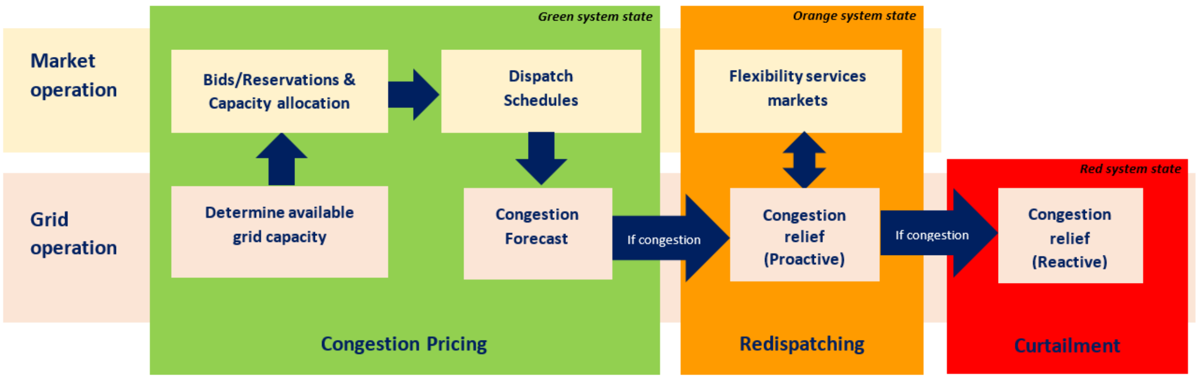
* The authors would like to acknowledge the feedback received by discussing this topic in different settings, such as: the focus groups, workshop, and online debates organized by the Florence School of Regulation; a meeting organized by European Commission (DG Energy) with Horizon 2020 project working on this topic; the DSO chair partnership a Vlerick Business School; and The Future Power Market Platform workshop. We would also like to thank Jean-Michel Glachant, Ross Baldick, Nico Keyaerts, Tim Schittekatte, Ariana Ramos, Martin Roach and Nicolò Rossetto for their feedbacks on earlier draft of the paper.

The paper is structured into 5 sections. Following this introduction, section 2 introduces the framework we applied to classify and review congestion management approaches. Section 3 consequently discusses the state of the art cooperation among TSOs. Section 4 then analyses various options for DSO-TSO cooperation, inspired by what DSOs are already doing, and by the TSO experiences. Finally, section 5 presents conclusions of the paper.

2. Review of congestion management approaches

In this study, we categorize congestion management approaches with respect to different states of a power grid system operation, while explicitly capturing the interaction between market and grid operations under each system state. Accordingly, we focus on three main congestion management approaches; namely, congestion pricing, redispatching and curtailment; each representing different system state, like the traffic light as shown in Fig. 1.[1] Note that, the different system states are not necessarily linked with the operational time frame of a power system. That is, each state can have both long term and short term dimensions.

Fig. 1: Conceptual representation of market and grid operation phases with respect to congestion management (Source: Authors)



In Fig. 1, congestion pricing approach corresponds to the green system state where the system operator determines the available grid capacity that can be offered to market participants. This capacity is allocated in the wholesale market either through implicit or explicit auctioning.[2] Once the available capacity is allocated and the market clears, the system operator updates its congestion forecasts based on the most recent information of the network status, utilization and generation dispatch schedules. If no mismatches between market outcome and network status are forecasted, no congestion relieving measures are necessary. This implies that the market outcome has captured all network constraints, or the grid is overly dimensioned to accommodate any deviations. In this case, no intervention of the grid operator is required.

However, if mismatches are forecasted, the grid operator takes congestion relieving measures such as redispatching which is commonly applied by TSOs. This represents an orange system state in which the system operator intervenes by adjusting the market outcome so that it reflects the physical network reality. This approach requires proactively procuring reserves for redispatching purposes.

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[1] For a bibliographical survey of congestion management approaches from 211 different references, see (Kumar, Srivastava, and Singh 2005).

[2] Note that capacity could also be allocated through an administrative procedure; for example, ‘first come, first served’ and ‘on pro rata basis’.

Even after taking these measures in the orange state, the system operator may still have congestion in its network. In this case, it has to resort to curtailment of generators or loads to relieve congestion. This is a red or emergency state in which market solutions are not sufficient.

Note that the extent to which the system operator may have to apply each of these approaches depends on the grid condition and market design. First, if the grid is over dimensioned as a result of a fit and forget approach, the grid operator remains a passive network manager, always in a green state. That is, no significant redispatching or curtailment would be required. Second, if the market is well designed to reflect the physical reality of the system; i.e., markets are well designed to reflect structural network constraints, borders are optimally defined and allocated, and there is less need for congestion relieving measures in the orange and red system states.

2.1 Congestion management in a green system state

In a green system state, system operators either rely on the fit and forget approach or on electricity markets that price grid constraints and send grid users economic signals for efficient grid utilization. This is often referred to as congestion pricing approach.

Applying congestion pricing approach requires defining borders within the network where there is structural congestion and allocating the available capacity of these borders to grid users. In practice, we notice that these borders are sometime defined to reflect political boundaries, as is the case in some parts of European electricity market. If a border is not defined, then market participants will have guaranteed firm access to the network and will be able to exchange electricity freely, without capacity allocation. This is what we often refer to 'copper plate' in the discussions on transmission constraints, and 'fit and forget approach' when discussing distribution grid constraints, both referring to a similar issue.

Fig. 2 depicts a conceptual representation of possible borders which could be defined between:

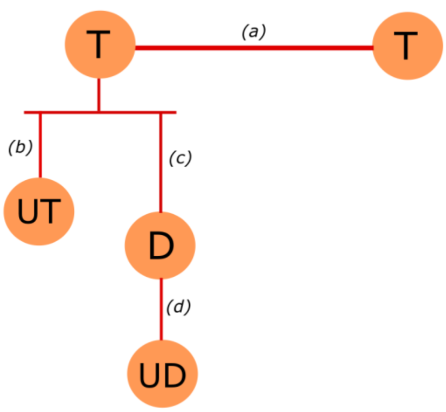
(a) two transmission systems (T) –> (T-T) border[3],

(b) a transmission system (T) and transmission grid user (UT) –> (T-UT) border,

(c) a transmission system (T) and a distribution system (D) –> (T-D) border, and

(d) a distribution system (D) and a distribution grid user (UD) –> (D-UD) border.

Fig. 2: Conceptual representation of borders between power grid systems and grid users (Source: Authors)



Once a border is defined, the available border capacity is allocated. The two common market-based capacity allocation approaches are: (a) explicit auctioning in which the capacity market and the wholesale energy market are separate; and (b) implicit auctioning in which the grid constraints are

[3] One transmission system per one bidding area is assumed.

integrated in the day-ahead wholesale market clearing algorithm, without organizing a separate market for allocating border capacity.

2.1.1 Explicit auctioning

Under explicit auctioning, grid capacity is allocated to market participants according to their willingness to pay for it. To do so, first, market participants offer a price coupled with the border capacity they would like to use. Afterwards, the bids are ordered by price and allocated to market participants until the maximum available border capacity is reached. That is, market participants with the highest willingness to pay are considered first in the allocation procedure.

There have been experiences with this approach at the transmission level. In Europe, it was implemented to allocate cross-zonal capacities; the (T-T) border as shown in Fig. 2. At the distribution level, the literature shows that this can be achieved by organizing a 'distribution grid capacity market' where capacity is allocated to aggregators and consumers with an optimized price. For example, a shadow price based allocation of distribution capacity has been proposed by (Biegel et al. 2012) and the operational sequences are described in (Bach Andersen, Hu, and Heussen 2012; Verzijlbergh, De Vries, and Lukszo 2014) with a case study for electric vehicles. Accordingly, first, the aggregators individually perform an optimization with zero network tariff and communicate their capacity needs to the DSO (or market operator). Then, the DSO checks if network constraints are respected or not. In case they are not, the DSO raises the network capacity tariff for the periods in which the capacity limit is exceeded. Using the updated grid tariff, the aggregators re-calculate their energy schedule. This procedure is repeated until it converges, resulting in a certain grid tariff and a binding capacity requirement for each aggregator. Finally, the aggregators can send their bids to the wholesale electricity market.

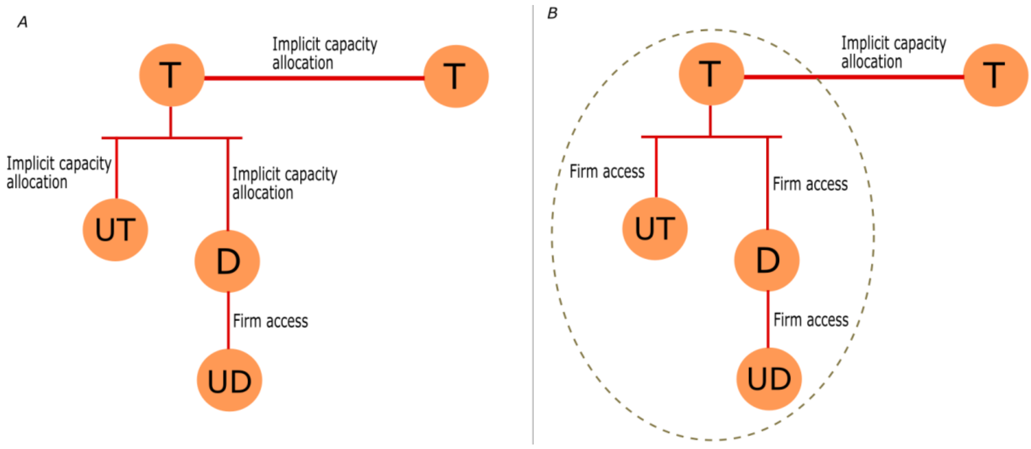
The explicit auctioning approach has been criticized for some of the inefficiencies it might result. The first source of inefficiency is due to the price information asymmetry between the auction for energy and capacity (Newbery and McDaniel 2002). There is a lack of information about the prices of the other commodity. This lack of information can result in an inefficient utilization of interconnectors, i.e. less social welfare, less price convergence and more frequent adverse flows. The second source of inefficiency is due to the complexity that could increase quickly with an increase in the number of congested lines for which capacity needs to be obtained through an auction procedure (De Vries, Laurens J. 2002). The third source of inefficiency is due to the vulnerability to market power abuse by generators that might strategically block capacity in order to raise prices (Bunn and Zachmann 2006).

2.1.2 Implicit auctioning

Implicit auctioning is all about dealing with the inefficiencies that could be caused by explicit auctioning. It does this by internalizing grid constraints in the day-ahead wholesale electricity market clearing algorithm. Unlike explicit auctioning, it does not separate demand and supply of energy from demand and supply of grid capacity. Hence, the resulting price reflects not only the cost of generating electricity but also the cost of transmitting and/or distributing electricity to final users. These prices are commonly known as locational marginal prices (LMPs). They could be defined on a nodal basis, where a separate energy price is computed for each node of the grid; or on a zonal basis in which the system is divided into relatively large pricing areas and a separate price is computed for each of them. A conceptual representation of implicit capacity allocation under nodal and zonal systems is shown in Fig. 2.

In a nodal system, shown in Fig. 3 (A), border capacity between transmission systems (T–T) and within the transmission network, referring to the (T–UT) and the (T–D) borders, are implicitly allocated. This system is often associated with the US electricity market. However, note that the UD-D border capacity is today not allocated, meaning users have firm access by default. In a zonal system, shown in Fig. 3 (B), it is assumed that the network within a zone is well dimensioned and no capacity allocation is required. This means grid users have firm access to the transmission as well as the distribution grid. This is the case in European internal electricity market where only the (T-T) border capacity is implicitly allocated in the wholesale market.

Fig. 3: Conceptual representation of implicit capacity allocation under nodal (A) and zonal (B) systems (Source: Authors)



The application of implicit auctioning at the distribution level remains rather an academic exercise. Based on the original work by (Bohn, Caramanis, and Schweppe 1984), some authors have extended the concept of implicit auctioning to the distribution level to reflect distribution grid constraints in the price for energy (Shaloudegi et al. 2012; Heydt et al. 2012; Meng and Chowdhury 2011; Singh and Goswami 2010; Sotkiewicz and Vignolo 2006; Li, Wu, and Oren 2014; Caramanis et al. 2016; Ntakou and Caramanis 2014). The resulting prices are commonly referred to as 'distribution locational marginal prices (DLMPs)'.

The limitation of this approach is its complexity for practical implementation, one reason being the fact that it requires advanced meters and ICT solutions (Pérez-Arriaga and Knittel 2016). Moreover, inefficiencies may arise depending on the implementation of the approach, as discussed in (Meeus 2011).

2.2 Congestion management in an orange system state

If congestion is expected after the day ahead market closure, system operators will have to take congestion relieving measures. The magnitude of these measures depends on (a) how well congestion is managed in the green system state, and (b) how well the grid is dimensioned. The mismatch between the market outcome and the physical reality could arise not only due to unpredictable events like a failure in one power plant, but also due to the serious oversimplification that assumes the grid within bidding zone is unconstrained. In Europe and elsewhere, this mismatch has recently become larger due to the increasing integration of variable renewable energy sources into the power system. With this variability in generation patterns, the location of congestion is becoming variable, while some structural congestion is also becoming evident in the internal network of several regions in Europe (Van Den Bergh et al. 2015). Consequently, the orange system state is becoming more frequent and increasingly more congestion relieving measures are being undertaken. One of the most common approach is redispatching.

Redispatching is any measure activated by one or several system operators, altering the generation and/or load pattern in order to change physical flows in the power system and relieve a physical congestion. It can be internal if redispatching is performed in the zone where the congestion is located; or external if redispatching is performed in zone A, whereas the congestion is in zone B.

At transmission level, most TSOs have been dealing with internal network constraints through the fit and forget approach, while few have decided to split their market into smaller bidding zones (e.g. Italy). Consequently, in the past, redispatching was a temporary solution and it was inexpensive or unnecessary in most cases. However, in recent years, implementation of redispatching measures by TSOs has become more frequent due to high feed-in from variable renewable energy generators. For example, in Germany, the redispatched energy amounted to around 16 TWh in 2015, which was more than three times as much as it was in 2014. This resulted in a redispatch cost of 412 million euros (BNetzA 2016).

At distribution level, redispatching would imply the DSOs procuring flexibility services directly from the energy resources connected to their grid or through an organized flexibility market[4]. So far, the experience is only limited to pilot studies. Furthermore, in most countries, there are no rules in place that allow DSOs to do that. However, the EU Clean Energy Package includes clear provisions that will enable DSOs to do so. For instance, article 32.1 states that: "*Member States shall provide the necessary regulatory framework to allow and incentivise distribution system operators to procure services in order to improve efficiencies in the operation and development of the distribution system, including local congestion management"* . The Clean Energy Package also highlights that DSOs shall procure these services in a transparent, non-discriminatory and market-based procedure (EC 2016b).

The limitation of this approach is its vulnerability to a potential abuse of market power, given the fact that only a small number of bidders may be located behind a grid constraint and compensation payments are related to the bids (Joskow & Tirole, 2000; Stoft, 1998). Gaming by generators has in the past played a role in the California electricity crisis (Joskow 2001; Wolak 2003). This was one of the reasons why many markets in US have shifted from a zonal pricing system to a nodal pricing system. Europe still has a zonal system and some zones have seen their redispatch cost significantly increasing; for example, in Germany where this challenge is putting pressure to split up of the market into smaller bidding zones, as has been done in the Nordic countries.

2.3 Congestion management in a red system state

Curtailment of loads and generators for congestion management is a last-resort action taken by system operators in an emergency state; i.e., when congestion is not relieved in the orange system state. Unlike redispatching which modifies the dispatch schedule through a trade, curtailment reduces the feed-in from generators or the in-take by loads. Moreover, costs resulting from redispatch are recovered through network charges, whereas curtailed users in the red system state are often compensated for their loss[5]. A review and analysis of renewable energy curtailment schemes are provided in (Kane and Ault 2014).

3. State of the art solutions at transmission level in Europe

Depending on the system state and the corresponding congestion management approach, different levels and types of cooperation could be required between system operators. In this section, state of the art solutions for inter-TSO cooperation in Europe are presented by referring to existing TSO practices and requirements of the European electricity network codes, focusing on the CACM, FCA, EBGL and SOGL. For detailed overview and discussion of these network codes, see (Meeus and Schittekatte 2017).

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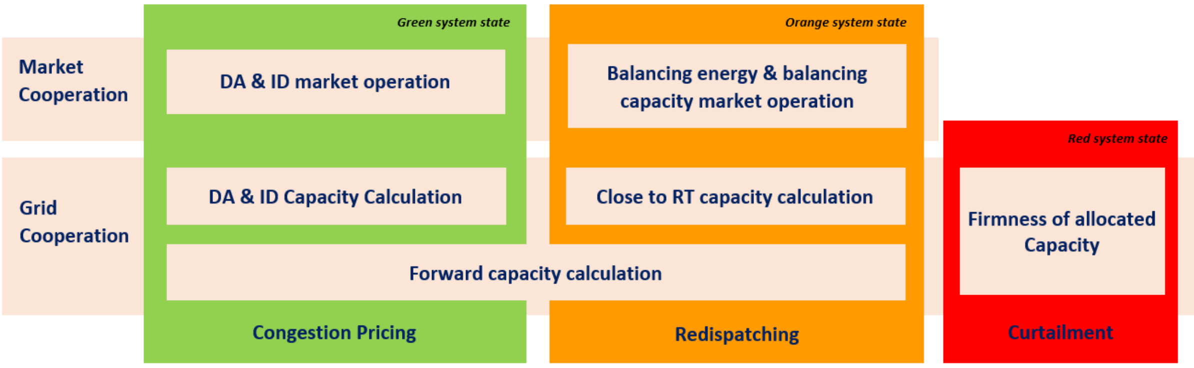
[4] One example of the proposed concepts for organized markets is the so called Flexibility Clearing House (FLECH) where aggregators assemble and mobilize the flexibility of DERs, pack and schedule flexibilities from individual DER, and offer the service to the highest possible bidder (Zhang et al. 2014).

[5] Curtailment is often associated with renewables which have priority dispatch privileges in Europe.

In general, inter-TSO cooperation can have both a market and a grid operation dimension depending on the system state. The market dimension is often related to the allocation of available border capacity while the grid dimension is related to the calculation of available border capacity that can be offered to the market and ensuring the firmness of allocated capacity. Fig. 4 presents both market and grid dimensions of inter-TSO cooperation that are required under each system state and the corresponding congestion management approach.

Fig. 4: Dimensions of inter-TSO market and grid cooperation relevant for each congestion management approach (Source: Authors)



3.1 Inter-TSO Cooperation under green system state

Under the green system state in which the market is designed to reflect transmission grid constraints, TSOs cooperate in two areas: (1) in operating the day-ahead and intra-day market with capacity allocation, and (2) in determining the available cross-zonal capacity that is offered to these markets.

3.1.1 Day-ahead and Intraday market operation with capacity allocation

All energy bids coming from market participants should be matched, taking into account available border capacity in an economically optimal manner while complying with technical requirements. In this regard, the experience from inter-TSO cooperation has been to couple and operate markets through power exchanges in which TSOs are often shareholders.

In the CACM guideline[6], a strong cooperation between potentially competing power exchanges is set as a requirement to establish a single day-ahead and intraday market all over Europe. Hence, an oversight and compliance with competition rules is considered of utmost importance. For this purpose, the CACM introduces a new entity called Nominated Electricity Market Operator (NEMO) which is an entity designated by a competent authority to perform tasks related to single day-ahead or intraday coupling. It also introduced a market coupling operator (MCO) function which is supposed to match orders from day-ahead and intraday markets for different bidding zones and simultaneously allocating cross-zonal capacity. Moreover, forward capacity allocation is considered crucial in order to move towards a genuinely integrated electricity market. This meant to provide efficient hedging opportunities for generators, consumers and retailers to mitigate future price risk in the area where they operate (EC 2009).

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[6] The goal of the CACM guideline is the coordination and harmonisation of capacity calculation and allocation in the day-ahead cross-border markets. It sets for this purpose requirements to develop a proposal for a day-ahead common capacity calculation methodology to ensure efficient, transparent and non-discriminatory capacity allocation. It was formally published on July 24, 2015 and after 20 days it entered into force.

3.1.1 Day-ahead and intra-day capacity calculation

An important step in the grid management process is to determine the available grid capacity that is allocated in the day-ahead and intra-day markets[7] either through explicit or implicit auctioning. The experience from inter-TSO cooperation shows that European TSOs have been calculating the available cross-border capacity using their respective methodologies, while the lower available capacity calculation of the two TSOs is finally offered to the market. However, this solution resulted in an inefficient use of available grid capacity, as shown in the ACER market monitoring report (ACER 2015). This is attributed, on the one hand, to the lack of coordinated calculation methodology while the available cross-zonal capacity is interdependent. On the other hand, it is because of possible misaligned incentives between offering cross-zonal capacity and minimizing internal congestion.

Cognizant of this, the CACM guideline requires that capacity calculation for the day-ahead and intraday market time-frames should be coordinated at least at regional level to ensure that capacity calculation is reliable and optimal capacity is made available to the market. Common regional capacity calculation methodologies have be established to define inputs, calculation approach and validation requirements. Information on available capacity should be updated in a timely manner based on latest information through an efficient capacity calculation process. To do so, a new entity called Coordinated Capacity Calculator (CCC) shall be established by a subset of TSOs and be responsible for the cross-zonal available capacity calculation within a capacity calculation region (CCR). The guideline also puts forward two permissible approaches when calculating cross-zonal capacity; namely, flow-based and based on coordinated net transmission capacity[8] while emphasizing its preference for a more advanced flow-based approach. Such calculation would also require updating the long-term transmission capacity allocated in the forward capacity market before the day-ahead. This way the TSOs can determine the available capacity that can be offered to the day-ahead and intra-day markets, as well as subsequent markets after intra-day market closure.

3.2 Inter-TSO Cooperation under orange system state

In the orange system state, TSOs have to procure flexibility[9] services to balance the system and manage network constraints that are not captured in the green system state. In what follows, we discuss the two main TSO cooperation experiences. First we look at the cooperation among TSOs to exchange balancing services. Second, we zoom in on the coordinated available transmission capacity calculations that will further improve the first cooperation.

3.2.1 Cooperation for the exchange of balancing services

The EBGL and the SOGL include two complementary ways to exchange balancing services across borders: 1) imbalance netting[10] and the exchange of balancing energy which have direct impact on the

[7] For the day-ahead market time-frame, individual values for cross-zonal capacity for each day-ahead market time unit shall be calculated using the flow-based approach as defined in the day-ahead common capacity calculation methodology, as set forth in Article 20(3) of the CACM Regulation. For intra-day, the CACM states that continuous trading should be in place with possible complimentary regional intraday auctions if approved by the regulatory authorities (see CACM, Article 63).

[8] The flow-based approach should be used as a primary approach for day-ahead and intraday capacity calculation where cross-zonal capacity between bidding zones is highly interdependent. The coordinated net transmission capacity approach should only be applied in regions where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach would not bring added value.

[9] In general, flexibility could be used by suppliers to optimise their portfolio, network operators to delay or avoid network reinforcement, and by system operators for balancing and constraints management purposes.

[10] Imbalance netting is defined in Article 3(128) of the SOGL as "a process agreed between TSOs that allows avoiding the simultaneous activation of FRR in opposite directions, taking into account the respective FRCEs as well as the activated FRR and by correcting the input of the involved FRPs accordingly."

balancing energy market; and 2) exchange of balancing capacity and sharing of reserves which have direct impact on the balancing capacity market.

Balancing energy market cooperation

The EBGL requires the establishment of common European platforms for operating the imbalance netting process and enabling the exchange of balancing energy from frequency restoration reserves (FRR) and replacement reserves (RR) (EC 2017). Towards this end, TSOs have gained experiences through pilot projects including the "International Grid Control Cooperation (IGCC), e-GCC, and the Imbalance Netting Cooperation (INC)[11]. It has been shown that such a cooperation can reduce the total volume of activated balancing energy and hence the overall balancing cost.

Similarly, the exchange of balancing energy over scheduling areas can help reduce the overall balancing cost. There are two models for the exchange of balancing energy across zones. The first model is the TSO-TSO model in which all interactions with balancing service providers (BSPs) are done through the TSO which operates the control areas in which the BSPs are active (i.e., connecting TSO). In this case, the border capacity can be implicitly allocated. The second model is the TSO-BSP model in which the contracting TSO has an agreement with a BSP in another TSO control area. In this case, BSPs have to reserve border capacity which is allocated through explicit auctions. According to the EBGL, the preferred model to ensure cost-efficient activation of bids is the TSO-TSO model while the TSO-BSP model remains an option for the exchange of balancing energy from FRR with automatic activation only if it is supported by a cost benefit analysis performed by all TSOs. Moreover, the EBGL includes steps towards harmonization of product definition and procurement practices. Note that the bids in the balancing energy market can also be activated for congestion management purposes, as indicated by ENTSO-E working group on Ancillary Services.[12]

Balancing capacity market cooperation

Complementing the imbalance netting and exchange of balancing energy, the EBGL also consider exchange of balancing capacity[13] and reserves as possible ways to ensure a more efficient reserve procurement and sizing. Similar to the approaches for coordinating balancing energy, both the TSO-TSO and TSO-BSP models are possible with the same preference and conditions. Moreover, according to the SOGL (Art. 3 (97)), TSOs can also go beyond exchange of balancing capacity by sharing and jointly dimensioning the reserve capacity they need to fulfil their reserve requirements (FCR, RCR or RR). Both exchange of balancing capacity and sharing of reserves can lead to lower overall volumes of balancing capacity and cost. Note that, unlike imbalance netting and the exchange of balancing energy, the exchange of balancing capacity and sharing of reserves are voluntary initiatives between two or more TSOs[14]. In terms of cross-zonal transmission capacity, both exchange of balancing capacity and sharing of reserves must reserve or anticipate for the needed transmission capacity.

3.2.2 Forward and close to real time (RT) capacity calculation

Inter-TSO cooperation in flexibility market operation (in this case, for balancing markets) requires close to real time and forward capacity calculations and updates to determine the border capacity that will be allocated or reserved for exchanges of balancing energy and balancing capacity. For the exchange of balancing energy or for operating the imbalance netting process, after the intraday-cross-zonal gate

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11 https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/Pilot_Projects/D150625_Report_P1.pdf

12 https://www.entsoe.eu/Documents/MC%20documents/balancing_ancillary/160519_Activation_Purposes.pdf

13 The exchange of balancing capacity is defined in Art. 2(25) of the EBGL as "*the provision of balancing capacity to a TSO in a different scheduling area than the one in which the procured BSP is connected.*"

14 EBGL, Art. 33 (1) and Art. 38 (1).

closure time, TSOs shall continuously update the availability of cross-zonal capacity, as stated in EBGL Art. 37 (1). Cross-zonal capacity has to be updated every time a portion of cross-zonal capacity has been used or when cross-zonal capacity has been recalculated. The EBGL also requires that five years after the entry of this regulation, all TSOs of a capacity calculation region shall develop a methodology for cross-zonal capacity calculation within the balancing timeframe for exchange of balancing energy or for operating the imbalance netting process.

With regard to balancing capacity market, Art. 38 (8) of the EBGL states that all TSOs exchanging balancing capacity or sharing of reserves shall regularly assess whether the cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is still needed for that purpose. Where the allocation process based on economic efficiency analysis is applied, this assessment shall be done at least every year. When cross-zonal capacity allocated for the exchange of balancing capacity or sharing of reserves is no longer needed, it shall be released as soon as possible and returned in the subsequent capacity allocation timeframes.

3.3 Inter-TSO Cooperation under red system state

In the red system state, a TSO may change the access to a firm capacity reservation of a flexibility service provider (FSP), in this case is the BSP, due to an emergency situation or in the event of force majeure[15]. Thus, inter-TSO cooperation is required to maintain the <u>firmness of allocated capacity</u> and deal with cases where this has to be violated.

According to the CACM, 'firmness' is defined as a guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed. The CACM also defines the day-ahead firmness deadline[16] and related compensation regime for transmission rights curtailed after such deadline (EC 2015). Accordingly, if a TSO curtails the allocated capacity because of force majeure or an emergency situation, the TSO shall reimburse or provide compensation for the period of force majeure or the emergency situation. However, this depends on whether this was an emergency situation or force majeure, and whether capacity was allocated implicitly or explicitly. If capacity was allocated via implicit allocation, the affected market participant shall not be subject to financial damage or benefit arising from any imbalance created by the curtailment. If capacity was allocated via explicit allocation, the market participants shall be entitled to reimbursement of the price paid for the capacity during the explicit allocation process if the event counts as force majeure or the event was an emergency situation but the bidding zone price is not calculated in at least one of the two relevant bidding zones in the relevant time-frame. Otherwise, the market participants would be entitled to compensation equal to the price difference of relevant markets between the bidding zones concerned if there was an emergency situation and the capacity was allocated via explicit allocation.

According to the FCA guideline (Art. 53 (1)), TSOs are entitled to curtail long-term transmission rights prior to the day-ahead firmness deadline to ensure that the system remains within operational security limits (EC 2016a). It also requires that TSOs report curtailments to their respective regulatory authorities and also publish the factual reasons that lead to the curtailment. Regarding the compensation it keeps the option that the concerned TSOs on a bidding zone border may propose a cap[17] on the total

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[15] Force majeure means any unforeseeable or unusual event or situation beyond the reasonable control of a TSO, and not due to a fault of the TSO, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial or economic point of view reasonably possible for the TSO, which has actually happened and is objectively verifiable, and which makes it impossible for the TSO to fulfil, temporarily or permanently, its obligations in accordance with this CACM guideline.

[16] According to the CACM guideline, 'day-ahead firmness deadline' means the point in time after which cross-zonal capacity becomes firm.

[17] This cap shall not be lower than the total amount of congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar year. In case of Direct Current interconnectors, TSOs may propose a cap not lower

compensation to be paid to all holders of curtailed long-term transmission rights in the relevant calendar year or the relevant calendar month in case of direct current interconnectors. Moreover, the FCA guideline does not exclude compensations for curtailment due to force majeure. Instead, it requires that the concerned holders of long-term transmission rights shall receive compensation for the period of that force majeure by the TSO which invoked the force majeure. In this case, the compensation shall be equal to the amount initially paid for the concerned long-term transmission right during the forward allocation process. Moreover, it requires that it shall be undertaken in a coordinated manner following liaison with all TSOs directly affected, and the TSO which invokes the force majeure shall publish a notification describing the nature of the force majeure and its probable duration.

4. DSO-TSO cooperation for distribution grid congestion management

Similar to the evolution of transmission level congestion management solutions and the corresponding inter-TSO cooperation, the solutions at distribution level are expected to take time and evolve according to new needs and developments in the electrical system. Therefore, solutions at the distribution level should take into account these developments and recognize the differences in the physical characteristics of the network, capabilities and complexities of the distribution and transmission systems. In this case, the solutions could come from two sources: 1) from the DSOs themselves, as it is already becoming evident with smart connection arrangement (SCA); 2) from the state of the art solutions at the transmission level, by extending these solutions to the distribution level.

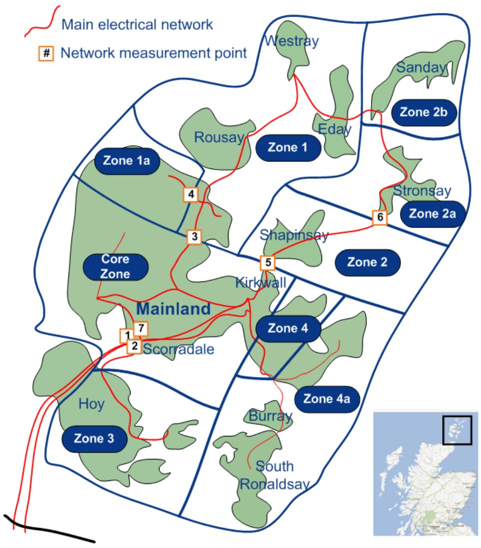
4.1 State of the art solutions from the distribution level

As distribution grids are getting constrained, some DSOs are already moving away from the fit and forget approach and are adopting new solutions. One interesting example of managing distribution grid constraints is the Smart Connection Arrangement (SCA). SCA implies that grid users, mainly new connections, have interruptible non-firm connections rather than the conventional non-interruptible firm connections which is subject to reinforcement in case of network constraints (Anaya and Pollitt 2015). SCA requires the implementation of active network management (ANM) system and defining borders where congestion is managed.

This approach is already implemented by the Scottish and Southern Energy Power distribution company on the Orkney Isles, as shown in Fig. 5. As can be seen, the distribution network is divided into zones with borders that represent constraint points in the network. The ANM system intervenes when real time information sent back to it exceeds any of the limits at these points.

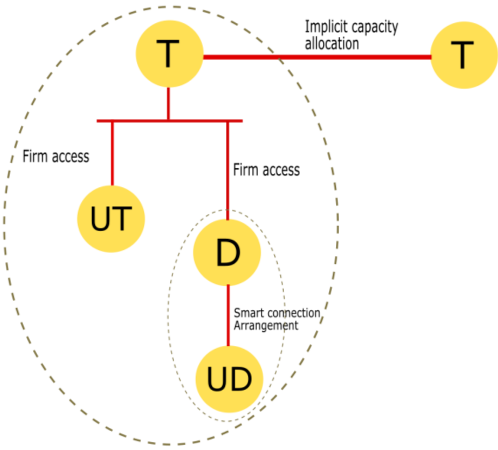
than the total congestion income collected by the concerned TSOs on the bidding zone border in the relevant calendar month.

Fig. 5: Distribution grid of Orkney Isles in Scotland (Source: http://anm.ssepd.co.uk/ANMGen.aspx)



With the introduction of the SCA, by actively managing the (D-UD) border, the DSO in this case is moving away from the fit and forget approach while the (T-D) and (T-UT) borders are still accessed without capacity allocation, as shown in Fig. 6.

Fig. 6: Conceptual representation of border where the SCA is applied (Source: Authors)



This approach could reduce the need to procure flexibility services for the purpose of redispatching and it could allow more distributed generators to be connected to the grid without major grid reinforcement. Moreover, it can improve the business case of distributed generators (Anaya and Pollitt 2015; Currie et al. 2010; Klinge Jacobsen and Schröder 2012) [18].

Table 1 shows the cost comparison of accommodating additional wind by reinforcing the grid against the cost of applying smart connection with active network management for three cases in the UK.

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[18] Note that the attractiveness of this approach depends on the size of the DG plant (Anaya and Pollitt 2015).

Table 1: Cost comparison of smart connection versus reinforcement (Source: Based on *(Kane and Ault 2014)*)

	Additional wind [MW]	Smart connection [Million euros]	Reinforcement cost [Million euros]
Orkney Isles	25	0.5	30
Shetland[19]	10 - 15	33.54	300
Flexible plug & play (FPP)	24.2	6.7	15.3

The cost saving by moving to SCA are very significant; however, this approach may expose distributed generators (DGs) and other market players such as balancing responsibility parties (BRPs) to a market risk because their generation (or load) might be curtailed (Klinge Jacobsen and Schröder 2012). This is especially the case if no curtailment compensations are provided. For the DGs, curtailment would mean no or lower revenues while they have to cover their fixed costs; hence, making loss. Given that the number of operating hours for most of the technologies such as wind is a determining factor to have a positive business case, non-firm connection and access increases the uncertainty on the revenues and consequently it leads to higher financing cost. For the BRPs, who have to balance the curtailed DGs, the expected output of the generators is part of their sourcing portfolio to cover the demand of their customers. When the forecasted demand is not available due to curtailment, the BRPs will have to look for replacement energy in the day-ahead, intraday or balancing markets.

Yet, according to (Anaya and Pollitt 2017), the distribution of the benefits of implementing smart connection approach indicates that the DGs are the main beneficiaries while DSOs and the wider society benefit less. This is because electricity generation benefits represent the highest proportion of the total benefits of the approach. Anaya & Pollitt (2017) also propose an incentive scheme that encourages the DSO to connect DGs more quickly and efficiently while contributing to the reduction of unnecessary network reinforcement that is usually borne by end customers. Moreover, innovative commercial arrangements have been proposed to efficiently allocate curtailment risks by (Anaya and Pollitt 2014; Kane and Ault 2014). Note here that if these commercial arrangements include curtailment compensation and this compensation becomes larger than the cost of reinforcing the network, the fit-and-forget approach could become more efficient. The same reasoning applies to redispatching cost.

4.2 Extending state of the art solutions from transmission to distribution level

An alternative source of solutions for the distribution level can be to extend the state of the art congestion management solutions and the corresponding inter-TSO cooperation. In this section, we discuss the extent to which the various state of the art inter-TSO cooperation solutions presented in section 3 could be extended to DSO-TSO cooperation. In doing so, we discuss DSO-TSO cooperation that could be needed depending on how the DSO manages congestion in the distribution grid under different system states. Moreover, we identify various implementation issues that might arise.

4.2.1 DSO-TSO cooperation in the green system state

In the green system state, DSOs could apply congestion pricing approaches to price constraints in the distribution grid. That is, distribution grid capacity could be allocated either through implicit or explicit auctioning as discussed in section 2.1. This would become relevant when the distribution grid is constrained and the DSO can no longer guarantee firm access to its grid users without capacity allocation.

[19] This includes a 6 MWh battery, a district heating system and domestic demand side management scheme.

Such a market based capacity allocation can be done either only at the distribution level or it can be integrated with the wholesale market with capacity allocated via implicit auctioning. The choice depends on the location of the structural congestion and on whether this is solved using the conventional fit and forget approach, or by splitting the zone and managing the cross-zonal border capacity. In the latter case, borders are defined and the DSOs have to establish a grid model which includes estimates on generation, load and network status.

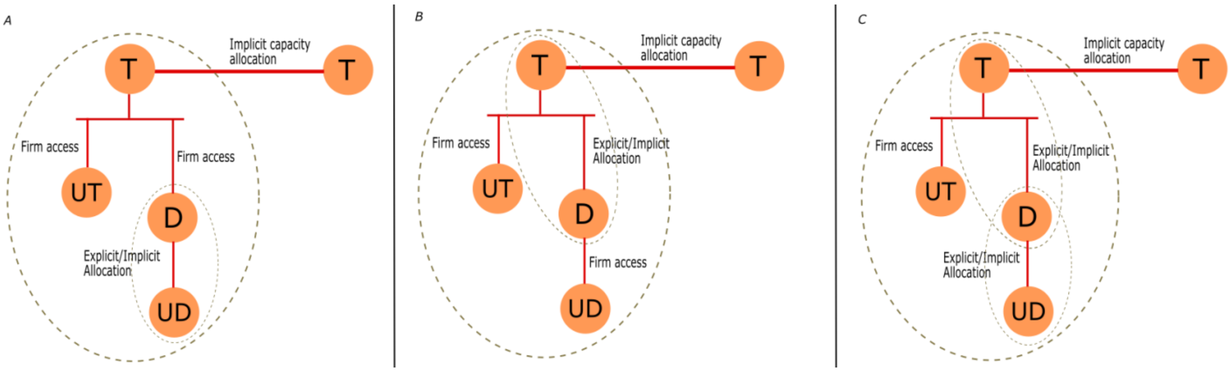
Fig. 7 shows the three possibilities of applying implicit or explicit allocation by the DSO, depending on where the structural congestion occurs.

A. The first possibility is to allocate capacity of the (UD-D) border. In this case, the D-T border can still be used without allocation; i.e., providing firm access. See Fig. 7 (A).

B. The second possibility is to allocate capacity of the (D-T) border while providing firm access on the UD-D border. See Fig. 7 (B).

C. The third possibility is to allocate capacity of both the (D – T) border and (UD – D) border. See Fig. 7 (C).

Fig. 7: Conceptual representation of applying implicit or explicit capacity allocation by the DSO



DSO-TSO cooperation on border capacity calculation is important for options (B) and (C). Furthermore, as there is a hierarchical relationship between the distribution and transmission system, this may call for introducing a network code that clarifies whether the DSO has to adapt its capacity calculation to that of the TSO or vice versa, or there will be a new entity that jointly calculates them using a common methodology similar to the proposal of the CACM for inter-TSO cooperation.

However, today in Europe, congestion is priced at the cross-zonal borders, assuming the internal network, including that of the distribution grid, is a copper place. Hence, this could raise questions regarding the relevance and benefits of adding such complexity to the existing market and grid operation. This calls for further research.

4.2.2 DSO-TSO cooperation in the orange system state

In the orange system state, the DSO would have to redispatch the generators and loads on its grid to deal with a congestion that is not captured in the green system state. This requires procuring flexibility services by DSOs which is not the case today but it has been proposed by the new EU Clean Energy Package (EC 2016b).

Currently, TSOs are the only ones procuring flexibility services connected to the distribution grids while the role of the DSO is limited to validating that the flexibility service provider (FSP) can provide the service without capacity allocation. This is rather a weak form of cooperation and it has been the main trigger for the debates around DSO-TSO cooperation in Europe. That is, the use of flexibility for balancing and network management actions at the transmission level will impact distribution network operation; and the use of flexibility by DSOs for local network management could impact the global system balancing. In this regard, article 182 of the SOGL requires DSO-TSO cooperation in order to facilitate and enable the delivery of active power reserves connected to the distribution systems. Specifically, it requires TSOs to develop and specify the terms of exchange of information for the purposes of the prequalification process for FCR, FRR and RR, in an agreement with reserve connecting and intermediate DSOs. By contrast, when a TSO contracts flexibility services directly from a resource connected to the network of another TSO (i.e., the TSO-FSP model and specifically, for balancing - the TSO-BSP model), the FSP is required to make reservations and the transmission capacity is explicitly allocated for this purpose. Similarly, if the (T-D) and (D-UD) borders are defined, the explicit allocation could be in one of these border or both borders. In this case, the DSO and TSO could cooperate in (re)calculating the border capacity that can be made available for the flexibility market operation both in terms of capacity and energy, as discussed in section 0 for balancing energy and balancing capacity markets.

Yet another extension could be made related to the TSO-TSO model for exchange of flexibility services. The equivalent to this model is the TSO-DSO model for flexibility service exchanges between transmission and distribution systems where all interactions are dealt with between the TSO and DSO. Under this model, the operators jointly procure flexibility services and depending on the existence of structural congestion between the two grids, borders could be defined and capacity could be implicitly allocated, similar to that of TSO-TSO model at transmission level. That is, the capacity could be allocated on the (D-T) border or on both (D-T) and (D-UD) borders, depending on where the structural congestion occurs. The type of DSO-TSO cooperation in this case could also be in determining the (D-T) border capacity that needs to be reserved for flexibility service exchanges and in the operation of the flexibility market, both in terms of energy and capacity. Some pilots are already looking into joint procurement of these services and market design proposals are being put forward (Roos 2017).

Here, it should be noted that with more innovative solutions to deal with distribution grid constraints such as SCA are introduced, the need and nature of DSO-TSO cooperation could change. Furthermore, the cooperation among DSOs themselves could become more important.

4.2.3 DSO-TSO cooperation in the red system state

In the red state, only technical measures can be taken to relieve congestion. DSO-TSO cooperation could become relevant if (1) there already exists an interaction between the DSO and TSO in managing congestion in the green and orange states; and (2) there are borders where the firmness of allocated capacity needs to be maintained. For example, if an FSP connected to a distribution grid has border capacity rights that allows it to sell services to the TSO, this could be curtailed in the red state. In this case, compensation could be foreseen similar to the inter-TSO cooperation. Yet this requires allocation of border capacity rights which is not the case today.

5. Conclusions

The role of DSOs is evolving due to the increasing penetration of intermittent and distributed energy resources in the distribution system. On the one hand, TSOs are accessing flexibility resources connected to the distribution grid. On the other hand, DSOs are beginning to actively manage distribution grid constraints, moving away from the conventional fit and forget approach. These new developments have increasingly raised the need for DSO-TSO cooperation.

In this paper, we provide an overview of the issues and possible solutions. We do that by reviewing the literature, the state of the art DSO practices, and the TSO-TSO cooperation experiences. We find that the DSO-TSO solutions we will implement might be different from TSO-TSO solutions because distribution grids are different from transmission grids, but the issues will remain the same. We also note that the language we are currently using to talk about these issues at distribution level is different from the language that is used at transmission level. For instance, at distribution level we talk about moving away from fit-and-forget, while at transmission level we typically talk about moving away from a copper plate approach. The difference in language sometimes suggests that we are talking about different issues, while they are actually very similar issues.

First, we summarize our findings regarding the issues. In this paper, we distinguish market operation from grid operation issues. Grid operation issues are related to the determination of the available grid capacity that can be offered to the market at the different stages from forward, to day-ahead, intra-day and close to real-time. Cooperation consists of having a harmonized calculation methodology and a common grid model with shared scenarios and input data for the calculations. Market operation issues are related to the allocation of the available grid capacity to the different market stages. Cooperation then typically includes wholesale market coupling in the green system state, as well as, using the remaining grid capacity in the orange system state to balance the system and to manage congestion. In the red system state, one operator might interfere with the services reserved by another operator, so that compensation is also an important issue that needs to be addressed.

Second, we highlights our findings regarding the solutions. The key questions are: where will we get structural congestion in the distribution grids; and at which border will we manage that congestion? We can manage it at the border between the transmission and the distribution grid, or at the border between the distribution grid users and the distribution grid, or a combination of the two. In the case of transmission grids in Europe, the focus has been on the border between operators. In the case of distribution grids, DSOs have already started to experiment with managing distribution connections smartly rather than focussing on the border between distribution and transmission. It will be interesting to see how this will develop.

The border between transmission and distribution grids is currently managed by a DSO pre-qualification process that is foreseen for balancing services connected to distribution grids that are offered to the TSO. This pre-qualification process is a first step towards defining a TSO-DSO border. In the future, the same issues will arise on that border as with TSO-TSO borders. The calculation and the allocation of the available capacity on the border will be challenged, and methodologies will need to be developed to increase the transparency of the approaches followed by the system operators. This will require increased cooperation and coordination between TSOs and DSOs.

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