DSO-TSO cooperation issues and solutions for distribution grid congestion management

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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, in the context of the European electricity market design and regulation. Second, we discuss viable 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. We also note that cooperation between DSOs as well as between DSOs and microgrids could become more important with the development of local energy markets in the long term.

Keywords

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

Acronyms

CM	Congestion Management
DSO	Distribution system operator
TSO	Transmission system operator
T	Transmission system
D	Distribution system
UT	Transmission grid user
UD	Distribution grid user
CACM	Capacity allocation and congestion management
FCA	Forward capacity allocation
EBGL	Electricity system balancing guideline
SOGL	System operations guideline
LMP	Locational marginal prices
DLMP	Distribution locational marginal prices
DA	Day-ahead
ID	Intra-day
NEMO	Nominated Electricity Market Operator
MCO	Market Coupling Operator
CCC	Coordinated Capacity Calculator
CCR	Capacity calculation region
FRP	Frequency Restoration Process
FRCE	Frequency Restoration Control Error
FRR	Frequency Restoration Reserves
EU-CEP	EU clean Energy package
ISO	Independent System Operator
EDSO	European Distribution System Operators
CEDEC	European Federation of Local Energy Companies
CEER	Council of European Energy Regulators
EC	European Commission
ACER	Agency of council of energy regulators

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 (Anaya and Pollitt, 2017; Eurelectric, 2013a; Gómez San Román, 2017; Klinge Jacobsen and Schröder, 2012; Ruester et al., 2014). 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, 2016a). 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 analysed potential DSO-TSO coordination 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 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 as well as DSO-DSO cooperation.

In this paper, we framed our analysis in the context of the current institutional setting and the proposals of the EU clean energy package. That is, the DSO and TSO businesses are separate; DSOs are not fully unbundled; and TSOs have the responsibility to keep the entire system in balance while DSOs are expected to start procuring system services for other services such as congestion management. In addition, we take a short-term perspective in which local energy markets are not yet part of the power system. These assumptions are then relaxed to study the implication of changes in the current institutional setting and local energy markets on DSO-TSO cooperation in the long term.

In the remaining part of the paper, section 2 introduces the framework we applied to classify and review congestion management approaches. Section 3 applies this framework to discuss the state-of-the-art cooperation among TSOs. Section 4 analyses various solutions for DSO-TSO cooperation, inspired by what DSOs are already doing, and experiences at the transmission level. In section 5, we take a long-term perspective and discuss the implications of institutional changes and local energy markets for DSO-TSO cooperation. Finally, section 6 concludes the study.

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 system state can have both long term and short-term dimensions.

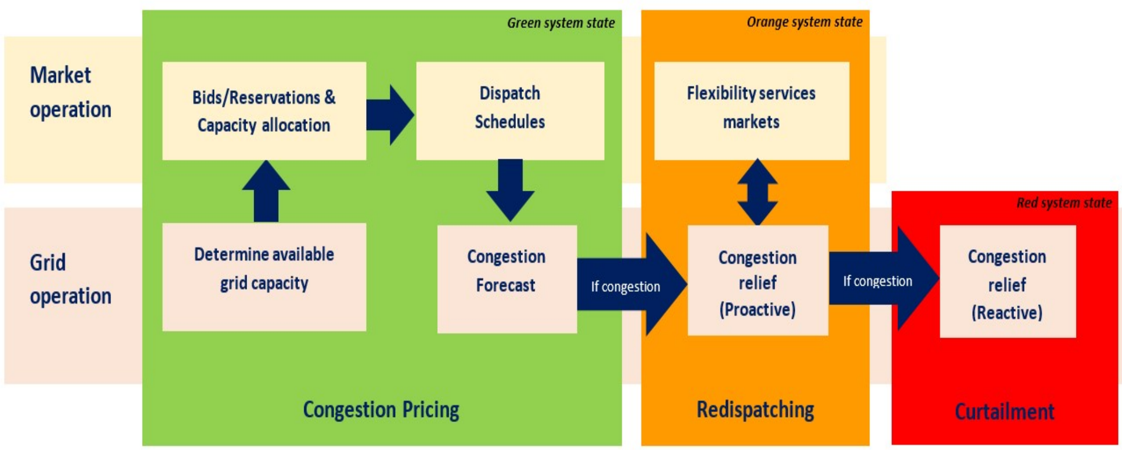

Fig. 1: Conceptual representation of market and grid operation phases with respect to congestion management (Source: Authors)

In Fig. 1, congestion pricing approach corresponds to <u>the green system state</u> 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

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

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. Even after taking these measures in the orange state, the system operator may still have unexpected 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 because 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

[2] Note that capacity could also be allocated through an administrative procedure; for example, 'first come, first served' and 'on pro rata basis'. Detail explanation of implicit and explicit capacity allocation are provided in section 2.1.

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 market design that prices 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 sometimes 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.

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,

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

(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.

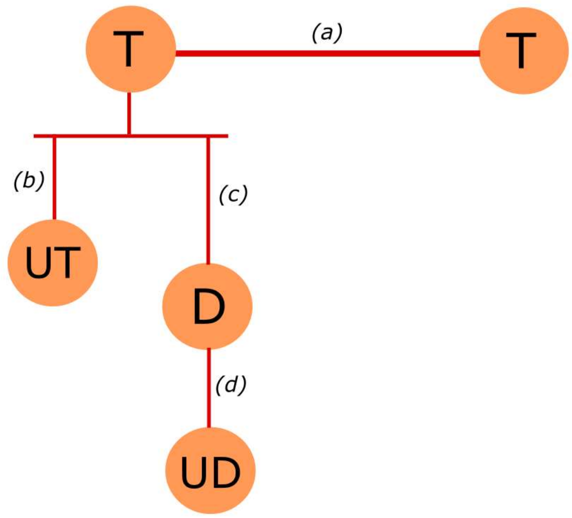

Fig. 2: Conceptual representation of borders between power grid systems and grid users (Source: Authors)

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 integrated in the 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 et al., 2012; Verzijlbergh et al., 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. 3.

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.

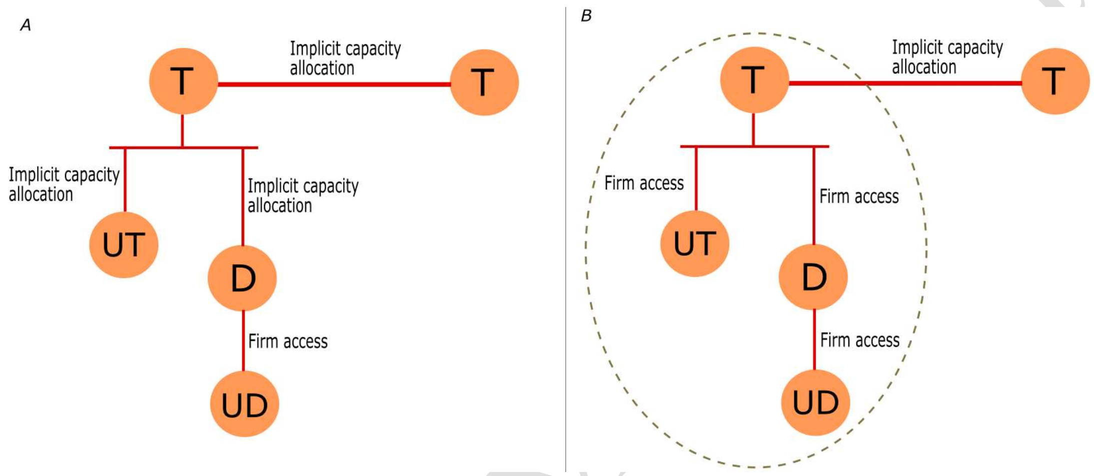

Fig. 3: Conceptual representation of implicit capacity allocation under nodal (A) and zonal (B) systems

The application of implicit auctioning at the distribution level remains rather an academic exercise. Based on the original work by (Bohn et al., 1984), some authors have extended the concept of implicit auctioning to the distribution level to reflect distribution grid constraints in the price for energy (Caramanis et al., 2016; Heydt et al., 2012; Li et al., 2014; Meng and Chowdhury, 2011; Ntakou and Caramanis, 2014; Shaloudegi et al., 2012; Singh and Goswami, 2010; Sotkiewicz and Vignolo, 2006; Yuan and Hesamzadeh, 2017). 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 and intraday 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 by expanding and reinforcing the grid, while a 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

[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).

Package also highlights that DSOs shall procure these services in a transparent, non-discriminatory and market-based procedure (EC, 2016a).

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 and Tirole, 2000; Stoft, 1999). 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 cooperation 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).

In general, inter-TSO cooperation can have both market and 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.

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

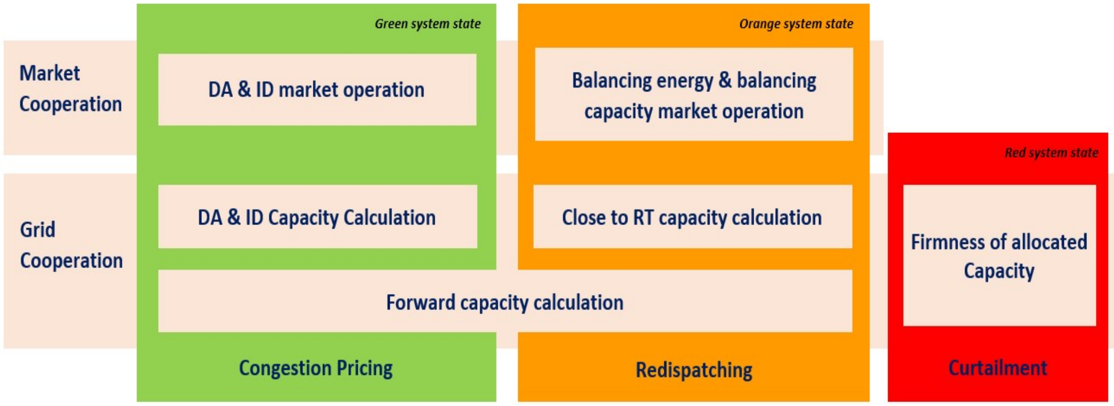

Fig. 4: Dimensions of inter-TSO market and grid cooperation relevant for each congestion management approach (Source: Authors)

3.1 Inter-TSO Cooperation under green system state

As shown in Fig. 4, 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).

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

[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.

[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).

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 to 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-

[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.

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] for system services including system balancing and managing network constraints that are not captured in the green system state. The dominant practice at transmission level is that TSOs procure the services for balancing and sometimes the bids that are submitted can be activated for congestion management purposes[10]. Moreover, the EBGL requires location information to be included in balancing bids. However, there are a few countries where the services are procured separately for example in Germany.

In what follows, we discuss the two main TSO cooperation experiences in balancing markets, considering that some bids can also be used for congestion management. 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.

[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. In this study, we use it in the context of system operators. That is, it mainly refers to services including system balancing and congestion management.

[10] See ENTSO-E working group study on Ancillary services https://www.entsoe.eu/Documents/MC%20documents/balancing_ancillary/160519_Activation_Purposes.pdf

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[11] and the exchange of balancing energy which have direct impact on the 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)[12]. 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

[11] 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."

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

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.

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

[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).

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 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 firmness of allocated capacity 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,

[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.

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, 2016b). 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 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

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

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.

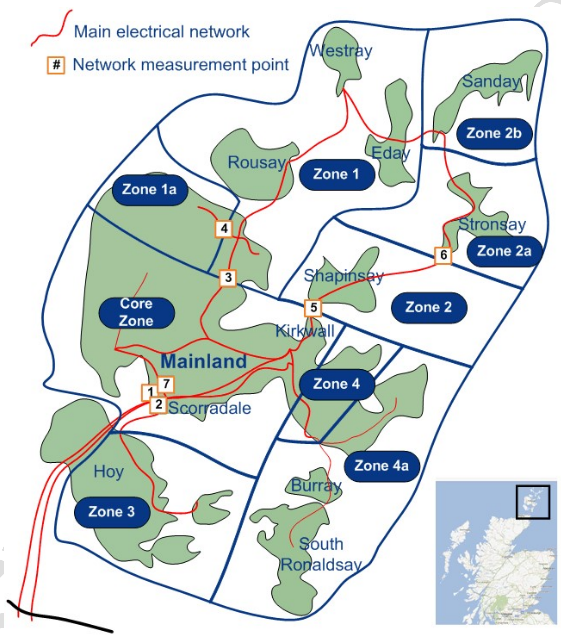

Fig. 5: Distribution grid of Orkney Isles in Scotland (Source: http://anm.ssepd.co.uk/ANMGen.aspx)

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.

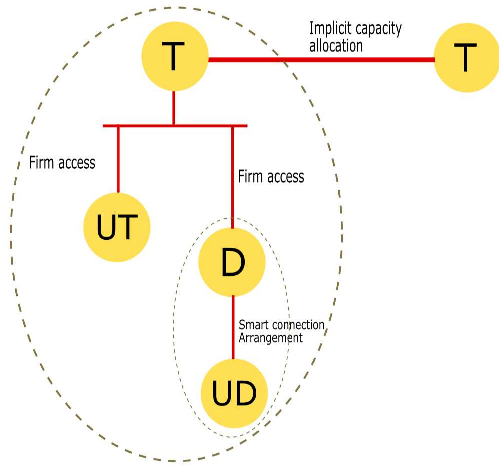

Fig. 6: Conceptual representation of border where the SCA is applied

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.

	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

Table 1: Cost comparison of smart connection versus reinforcement (based on (Kane and Ault, 2014))

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

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

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 and 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

Alternative solutions for the distribution level can be inspired by the state-of-the-art solutions for inter-TSO cooperation. In summary, we have seen that in the green system state, the TSOs cooperate on calculation of grid capacity to be offered to the market and the operation of these markets. In the orange state, the TSOs cooperate in the procurement of system services including balancing and congestion management, and the operation of the markets that offer these services. The grid related cooperation is mainly on the grid capacity calculation. In the red system state, the only cooperation is grid related which is ensuring firmness of allocated capacity and compensation for emergency curtailment.

In this section, we discuss the extent state of the art inter-TSO cooperation solutions presented in section 3 could be extended as solutions for 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.

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.

When a market based capacity allocation is pursued as a solution to deal with congestion that involve the distribution system, there are three possibilities of applying implicit or explicit allocation by the DSO, depending on where the structural congestion occurs. These are shown in Fig. 7 and discussed in what follows.

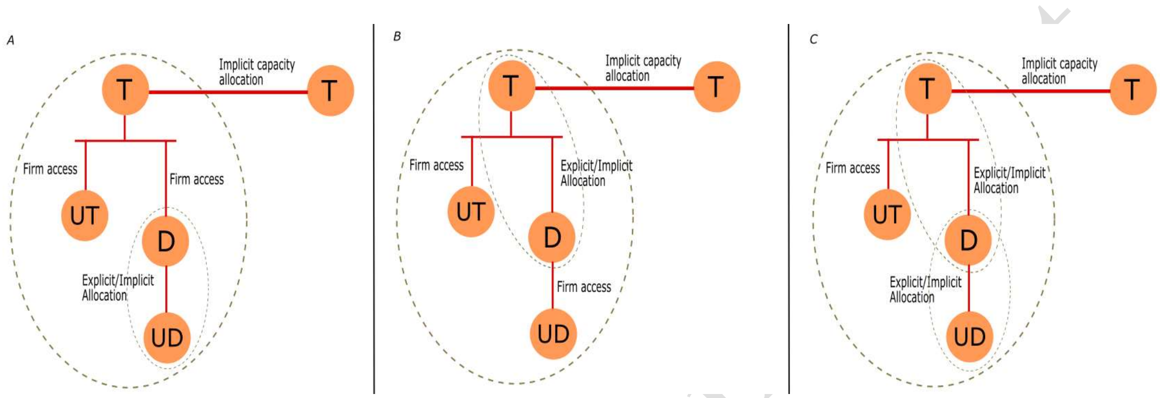

Fig.7: Conceptual representation of applying implicit or explicit capacity allocation by the DSO

A. Only the (UD-D) border has structural congestion

As shown in Fig. 7 (A), the (D-T) border can still be used without allocation; i.e., providing firm access, while the structural congestion is within the distribution grid. This border can either link the different voltage levels of a given distribution grid or horizontally link network areas on the same voltage level. In the latter case, this could be a border between two DSOs which requires DSO-DSO cooperation for grid capacity calculation. The market-based solution for this would be to allocate the capacity using explicit or implicit auctions.

An explicit auction would mean the market operator allocates the available capacity to market participants who have to adjust their bids before they submit it to the wholesale market. The main role of the DSO in this case is to calculate available grid capacity and offer it to market participants. This could be done in cooperation with neighbouring DSOs, and the TSO should take it into account while calculating the capacity for interconnection with its neighbouring TSOs. Or the other way around – the DSO takes into account the calculation of the TSO, and the DSO adjusts its calculation at the distribution level. However, who would operate this market is not obvious, it could be the DSO or separate market operator. Alternatively, capacity can be allocated using implicit auctions, implying that the constrained border would be included in the wholesale market clearing algorithm (or a local market which is not the case today). Depending on where the border is, different price zones are created within the distribution system. This would mean creating a zone within a zone – more like an 'enclaved' zone. Though technically feasible, this solution sounds complicated given the current set up of the European electricity market which does not reflect internal network constraints at transmission level within a zone or country.

B. Only the (D-T) border has structural congestion

In the case of Fig. 7 (B), the congestion is only on the border between DSO and TSO grid. If the capacity is allocated explicitly, the main cooperation between the DSO and TSO is on capacity calculation which the TSO has to take into account in the calculation for its border with neighbouring TSOs. The issue here is related to who participates in this auction, only the DERs and aggregators participating in the wholesale market, or including participants connected to the transmission system who sell electricity to suppliers connected to the distribution grid. In contrast, if capacity is allocated implicitly, an enclaved zone within a zone is created similar to case A, raising similar issues.

C. Both the (D – T) and (UD – D) borders have structural congestion

In the case of Fig. 7 (C), the structural congestion is on the border between the DSO and TSO, as well as within the distribution system. Here, any combination of implicit and explicit auctioning can be foreseen with various level of complexity and feasibility in reality, as discussed in Case A and B.

The common issue across these solutions is what would be the benefit of creating a zone within a zone and pricing it differently? How would this be implemented in reality? Would this be socially and legally feasible? Furthermore, as there is a hierarchical relationship between the distribution and transmission system, this requires clarifying whether the DSO has to adapt its capacity calculation to that of the TSO or vice versa, or an independent entity jointly calculates them using a common methodology similar to the proposal of the CACM for inter-TSO cooperation. Until these open issues are resolved, any future constraints would have to be solved under the orange system state.

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, 2016a).

Currently, TSOs are the only ones procuring flexibility services connected to the distribution grids while the role of the DSO is limited to prequalification, validating that the flexibility service provider (FSP) can offer its services 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. This would be evident particularly when the time-frame of balancing actions by the TSO and congestion management by the DSO are simultaneous, and in a high-DER scenario. 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.

The first solution could be the TSO-FSP model. That is, if there is structural congestion in the (T-D), (D-UD) or both borders, explicit capacity allocation is performed in one of these borders 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, similar to balancing markets discussed in section 3. as discussed in section 3.2.1.

The second possible solution could be 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. 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).

Moreover, in the literature, most of the DSO-TSO cooperation solutions are designed with respect to the various ways of setting up flexibility markets for system services (also referred to as markets for ancillary services) in which the DSO and/or TSO are the buyers of these services. For example, (Gerard et al., 2017) evaluates five coordination schemes; namely, centralized market, local market, shared balancing responsibility model, common TSO-DSO market, and integrated flexibility market model. Among these, the centralized market model is considered as the most compatible model with the existing regulation and organization of these markets in Europe. The model requires the TSO to have priority, it operates the market and the DSO has no role that goes beyond pre-qualification. However, in the future, alternative schemes in which the DSO plays active role in grid operation could be needed.

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. Policy Implications

The analysis in this study has been framed in the context of the current institutional setting in the European electricity sector and the proposals of the EU Clean Energy Package. We have assumed that in the current institutional setting the TSO and DSO business are separated; DSOs are not fully unbundled; and TSOs have the role to keep the entire system in balance while DSOs are expected to start procuring system services for other purposes including congestion management. Moreover, we consider local energy markets are not yet fully developed and integrated in the existing electricity market design. However, in the long term this context could change, and it can have implications for the DSO-TSO cooperation. Thus, in this section, we take a long-term perspective in which the current institutional setting could change, and local energy markets could become part of the current electricity market design.

First, current players are trying to cooperate under the current institutional setting while the context around them is changing rapidly. The success of the solutions discussed in this paper therefore depends how well they navigate through the changing context especially in the distribution system, and how they deal with any possible institutional barriers. However, if these attempts fail to lead to a seamless DSO-TSO cooperation, the current institutional setting could be revisited. In this case, one possible institutional solution could be to remove the border between TSO and DSO and introduce an independent system operator (ISO) that is responsible for the operation of both transmission and distribution systems.

Other intermediate solutions are also being considered in countries where an ISO at the transmission level already exists. For example in USA, the Californian ISO considers a solution in which the DSO would have a market facilitator role that includes not only aggregating the bids of DERs and submitting it to the wholesale market but also cooperating with the ISO to calculate and determine the available capacity at the T-D border that can be allocated by the market (Kristov and Martini, 2014). An alternative is to let all DERs directly bid in the wholesale market. In this case the DSO has minimum role which is limited to prequalification. However, this solution is considered complex and difficult to scale in a high-DER scenario (Kristov and Martini, 2014)[20]

Second, the trend towards local energy systems and markets is slowly becoming evident. Local energy production and supply, local energy aggregation and smart microgrids are expected to be part of the future energy system (Eid et al., 2016; Koirala et al., 2016). Technological advances coupled with socio-economic and political factors

[20] Note that the DSO-TSO cooperation discussions are ongoing in Europe and US. However, the focus is a bit different due to the difference in the institutional setting. Currently, we could roughly position the discussions in the US as focused on the Green system state while that of EU on the orange system.

have been shaping this trend. New technologies such as blockchain and smart meter technologies are enabling energy aggregation, local energy exchanges and balancing. The increasing social awareness about climate change and the economic viability of local energy systems relative to centralized systems is motivating communities to engage in energy. Furthermore, new policy directions at the EU level are promoting the development of local energy systems; notably, article 16 of the EU-CEP includes a provision that is favourable for the development of local energy communities (EC, 2016b).

The implication of these developments for the DSO-TSO cooperation should be factored in any form of policy solutions that aim to improve cooperation. One aspect is related to the importance of DSO-TSO cooperation relative to the cooperation among DSOs in their distribution system. As more and more local energy communities desire to have the capability of local energy exchange, the development of local energy markets appear to be a possible future (Verreth et al., 2015). This development coupled with the diversity of DSOs in Europe both in number, size and structure (see (Eurelectric, 2013b)) can make cooperation among DSOs, and DSOs with communities that own/operate microgrids as important as DSO-TSO cooperation, if not more important.

Another aspect is how the role of the DSO would evolve amidst all these developments. The role of the DSO could include enabling local energy exchanges; integrating and operating local energy markets; and becoming the reference point for interactions with the wholesale market and transmission system operation. Relaxing the current institutional setting, recent studies have also looked into possible cooperation solutions that recognize this trend; for example, Gerard et al (2017) considers local market and shared balancing responsibility models compatible with the future role of DSOs and the possible distribution grid constraints. Both models allow the DSO and TSO to operate their respective flexibility markets while providing the DSO the priority, and local system balancing by the DSO in the case of the shared balancing responsibility model.

Moreover, the role of the regulator is very important as the regulatory frameworks could hinder or foster the development of efficient cooperation between system operators. Given the rapidly changing context, proactive regulators are needed. Yet, introducing strong regulatory measures comes with a risk that it might be no longer fit for the future scenario. In this regard, some regulators (e.g. Ofgem) have introduced regulatory sandbox concept where new concepts can be tested and studied without being restricted by the existing regulatory framework.

6. 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.

First, we summarize our findings regarding the issues. In this paper, we distinguish market operation from grid operation issues. Grid operation issues in the green and orange system state are mainly 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. In addition, under orange system state, it is also about procurement of flexibility for system services including balancing and congestion management. Under the red system state, it is mainly about maintaining firmness of allocated capacity and setting compensation rules in case of emergency curtailments. 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. We also note that the basic areas of cooperation including capacity calculation, joint procurement of system services, maintaining firmness of allocated capacity and market operation remain applicable to TSO-TSO, DSO-TSO, DSO-DSO as well as DSO-microgrid cooperation. The variation is on how the cooperation will be organized and whether the context requires such cooperation.

Second, we highlight 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. Moreover, the trend towards local energy systems might make DSO-DSO cooperation as important as the DSO-TSO cooperation, especially if the role of the DSO goes beyond pre-qualification to include local system balancing and local congestion management.

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, as well as between DSOs.

Third, we take a long-term perspective in which the single system operator model could become an alternative solution if cooperation in the current context fails to work. In addition, the development of local energy markets could lead to more new issues including DSO-DSO cooperation issues. In light of the changing energy landscape, it is important to explore all possible solutions and promote innovative solutions. In this regard, the regulator can introduce regulatory sandboxes which provide conducive environment to test new concepts such as local energy trading, and clarify the new roles that could be assumed by DSOs.

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