Project report

Market approaches for TSO-DSO coordination in Norway

February 2021

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Views, opinions and conclusions are of a general character and cannot be taken to represent specific Statnett positions on any of the topics treated in the report.


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1. Context and Problem Statement

The deployment of renewable resources and flexibility resources in medium and low-voltage distribution systems has generated an interest by the academic community and practitioners to design and implement "flexibility" platforms [18] in recent years. The potential benefits of such platforms are numerous. They can support an increased deployment of distributed renewable supply (e.g. rooftop solar), safeguard the distribution network and postpone distribution network expansion, and mobilize demand-side flexibility, which in itself produces numerous short-term operational efficiencies and long-term benefits in terms of generating robust investment signals for the market [19].

Flexibility platforms. Flexibility platforms in the context of the present project refer to platforms that enable the integrated operation of resources located in the transmission and distribution grid for the purpose of resolving balancing and congestion management. The integrated treatment of balancing and congestion is in line with the spirit of Nordic operations, where these functions have rightfully been treated as a coordinated step of operational planning and dispatch. This integrated treatment is further supported by the significant role of hydro resources in the system, which involve very limited lead times for being available to resolve imbalances and congestion in the system. Thus, and to be clear, a "flexibility platform" in the context of the present assignment refers to a market clearing platform that sends dispatch signals and prices used for settling the dispatch instructions at or very close to real time, e.g. in the timeframe of mFRR activation. It thus generalizes mFRR balancing platforms so as to accommodate resources that, although located in the distribution system, can respond to network operator dispatch instructions. Flexibility platforms, in the context of the present project, do *not* refer to the market operations that are required for booking the required capacity in advance of real-time operation, i.e. balancing capacity auctions. We also do not tackle questions of intraday market operations, as these too are considered as being out of scope for the present assignment.

Desiderata of flexibility platforms. We consider three important desirable attributes for flexibility platforms: (1) scalability, (2) consistent pricing / dispatch instructions, and (3) institutional compatibility. We discuss these desiderate in turn.

(1) *Scalability* refers to developing a solution that can accommodate a massive number of distribution system resources. Integrating transmission and distribution networks naturally leads to considering market clearing problems of very large scale. Caramanis et al. [18] provide an indication: "*In fact, whereas transmission bus locations number in the thousands, associated distribution feeder line buses number in the hundreds of thousands or millions.*". Thus, any developed solution should be capable of coping with the massive number of resources that are involved, both in terms of computational burden, as well as in terms of information communication technology requirements.

(2) *Consistent pricing / dispatch instructions* refers to the fact that the platforms should not generate gaming opportunities for their participants. Physical constraints including line

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congestion, voltage limits, reactive power flows, line losses, and so on, are important considerations in all networks, even more so in distribution networks where some of these factors can be more constraining. Pretending that these physical constraints do not exist when generating market prices creates opportunities for manipulating the market and extracting profits in exchange for providing no service whatsoever to the network operator, as exemplified for example by the infamous inc-dec gaming strategies that were developed in early flawed market designs [13, 14, 15], and more recently highlighted in the context of the EU design [16, 17]. These risks of gaming opportunities are not limited to the design of the wholesale market at the high-voltage level, but are equally present in the context of flexibility platforms clearing distribution system resources. Thus, we investigate whether the solution that we analyze in the project generates not only efficient dispatch instructions, but also consistent price signals, and we highlight difficult market design dilemmas that will need to be faced by network operators moving forward in order to minimize the scope for market manipulation in future flexibility platforms.

(3) *Institutional compatibility* refers to the fact that any proposed flexibility platform should be consistent with the roles and responsibilities of various market actors, as well as the information that is actually available to different network operators at the balancing timeframe. Concretely, it is important to highlight that the traditional role of distribution system operators (DSOs) has been limited to congestion management, i.e. ensuring that their own grid is operated securely. By contrast, the transmission system operator (TSO) assumes a more expanded role of congestion management at the wholesale level but also balancing the system overall, i.e. resolving any real-time power imbalances. Moreover, in real time, the imbalances at the network can only be observed at an aggregate level (e.g. through indicators such as frequency or Area Control Error - ACE) whereas dispatch instructions and prices may need to be issued at a highly granular level. Any proposed flexibility platform should account for the information that is actually available by each network operator in real time, and not rely on overly optimistic assumptions about how much information a network operator can observe in real time. Another example of institutional compatibility relates to whether or not the DSO is willing to share its network information with the TSO or surrender the control of its local assets, and whether the TSO is willing or able to assume control of distribution system assets or would rather not access system information at this level of granularity. An additional example of institutional compatibility relates to whether the DSO is permitted to even be involved in the operation of flexibility platforms, or whether such platform operations should be separated from the management of the distribution network by “outsourcing” the platform function to a separate provider. Different systems have different answers to these questions, and the discussion in the present report is rather focused on Nordic operations.

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The Nordic context. As mentioned earlier, flexibility platform designs should account for the specificities of different system. We now describe certain characteristics that are specific to the Norwegian system, and that interact with TSO-DSO coordination. We list these idiosyncratic features here, and return to them as they relate to the coordination schemes that we discuss throughout the report.

Dominant role of hydro. Relative to numerous systems which rely on conventional thermal power plants, Norway relies more on hydro. Hydro power is not significantly ramp constrained and does not require establishing the production schedule long before real time. This is conducive towards performing congestion management close to real time, leading to a rightful adoption of an integrated approach on balancing and congestion management in Nordic operations, and in line with international practices in other advanced markets.

Governance of the grid. Statnett has direct access to very detailed information about the distribution grid, down to the level of 33kV.

TSO balancing responsibility versus DSO-led flexibility activation. The TSO is responsible for coordinating the balancing of the grid and for managing congestion in both transmission and medium voltage distribution grid.. The reason that Statnett is responsible for handling congestion also in the medium voltage distribution grid is that 40 % of the installed production capacity is connected to the distribution level and that the utilization of the transmission and medium voltage level for most part is largely interdependent.

Network constraints. The Norwegian transmission grid tends to be more constrained than other control areas. As an illustration, historically around 50 % of activations from the mFRR market are used for resolving congestion and grid constraints / operational challenges within the bidding area (a term referred to in Norway as “special regulation”). These are activations that are made to deal with both transmission and distribution grid constraints.

Single imbalance price settlement for both consumption and generation will be implemented in 2021. A single price will apply to positive and negative imbalances (single imbalance pricing), and is therefore assumed to be the settlement method applied for the cases in this report.

We provide a simplified representation of the basic structure of the Nordic system in the following figure. Although there are certain variations to the basic structure, the figure captures a rough outline of the structure of the Norwegian system as well as some of the terminology that is employed by stakeholders. Roughly, station groups are the smallest possible denomination of mFRR bids. Our interpretation based on the information from discussions with Statnett is that station groups have a resolution of up to 33 kV (sometimes above), and not below (since they delineate resources with an aggregate capacity of 1 MW or more and only the 33 kV system is represented in the Statnett grid model for this level of resolution).

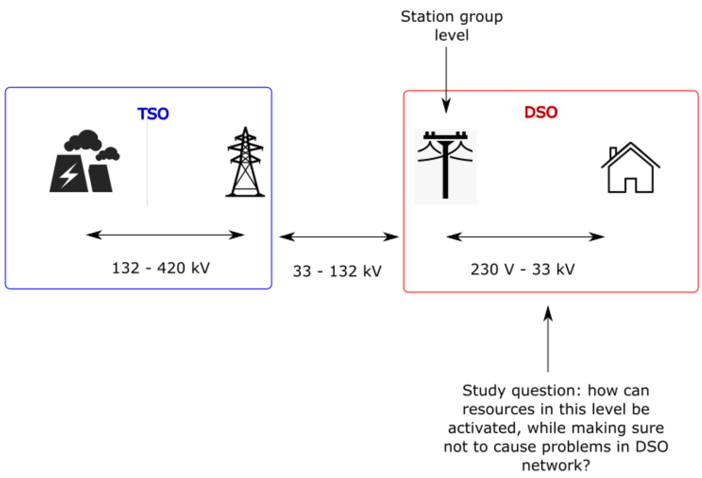

Figure 1: A simplified representation of the overall structure of the system under study.

Given the increasing proliferation of resources at the distribution system level, Statnett would like to be in a position to mobilize these resources for “flexibility”, which we refer to in this project as activation for balancing and / or congestion management. The question is how this can be achieved without causing problems in the distribution network, since Statnett does not have visibility of the distribution network.

Focus of this study. Given the increasing proliferation of dispatchable resources at the distribution system level, Statnett would like to be in a position to mobilize these resources for “flexibility”, which we refer to in this project as activation for balancing and / or congestion management. There are three specific variations that are considered in our report:

(1) A fully coordinated approach which represents an idealized but not necessarily implementable benchmark.

(2) A hierarchical approach, which strives to achieve the outcome of the fully coordinated approach in a scalable and institutionally manageable fashion but still presents non-negligible implementation challenges.

(3) A step-wise approach which attempts to bridge current practices in Norway to perfectly coordinated outcomes.

We note that the hierarchical approach considered in the present study may be considered to be a special case of the hierarchical approach which was outlined in the previous study (approach A2 in [2], also explained in [3], see also [4] where a hierarchical approach is described for the Smartnet project). In the following sections we will attempt to delineate how approach A2 in [2] could be translated to a proposal for tackling the main question of this study, with a concrete discussion on roles and responsibilities, TSO-DSO information exchange, and settlements. Specific emphasis should be placed on the order of access to resources.

2. Overview of existing coordination schemes

The academic literature as well as commercial projects and European research initiatives have brought forward various possible strategies for activating decentralized flexibility resources in a coordinated manner between TSOs and DSOs. This section aims at listing non-exhaustively some interesting strategies as well as highlighting their key differences by describing the main questions and choices that are at stake when developing a flexibility market. This allows us to outline the framework in which a consistent reflection about the most appropriate setup for Norway can be held.

2.1. Comparison criteria

In order to be able to easily identify the differences between the market schemes that can be contemplated for sourcing flexibility, this section establishes a list of criteria and "controversial questions" which describe a number of dimensions along which the flexibility markets differ with each other (the six first criteria listed below are discussed by Meeus in [5]):

1. **Is the flexibility market integrated in the existing sequence of EU electricity markets?**

   The flexibility market could be a completely separated process or could be integrated with wholesale and / or balancing markets (e.g., MARI). One main argument in favor of an integrated approach is liquidity [5]. In case the flexibility market is not integrated into the EU market, then there is the question of who has the responsibility to ensure balance responsibility and / or avoid double activations of the same unit.

   The present study considers primarily the full integration of TSO-DSO congestion management in the MARI process and therefore the interaction within the existing markets is an important question that will be investigated in the study.

2. **Is the flexibility market operator a third party?**

   In the EU, the day-ahead and intraday markets are operated by third parties while the balancing markets (national) are typically operated by the TSOs. One argument in favor of not having a third party is to avoid the additional complexity of implementing an interface between the TSO / DSO and the third party. Furthermore, one main argument in favor of having a third party operating the flexibility market is to ensure neutrality between buyers and sellers, this is particularly true in case the system operator also owns some flexibility.

   In the context of this study, it is assumed that the TSO is responsible for the operation of the balancing market. Interactions of the TSO with MARI are handled by a transmission-level aggregation-disaggregation service, which will be described in further detail in the sequel. The DSO is responsible for congestion within its own perimeter, while coordination with the

TSO is supported by a distribution-level aggregation-disaggregation service, which is further described in the sequel.

3. Are there reservation payments?

Depending on the context, the need to reserve flexibility upfront may be necessary to ensure secure grid operations.

While this may be an essential feature, it also falls out of the scope for the present study, which solely focuses on the activation process.

4. Are the products standardized?

The standardization of products is a valuable step towards enhancing liquidity in the market. However, different network operators employ different services for balancing and congestion management with important nuances. This is also reflected in the variety of balancing platforms (RR, aFRR, mFRR scheduled / direct activation, and so on). The alignment of product definitions is a necessary yet strenuous step towards the integration of balancing platforms and the coordination of TSOs and DSOs.

The present study assumes mFRR to be the "standard" product used for the entire flexibility market.

5. Is there TSO-DSO cooperation for the organization of the flexibility market?

This criterion is a key concern that has been studied for instance in SmartNet [8]. The more recent "CoordiNet" project [9], building on [8], has proposed a new classification of coordination schemes between the TSO and DSO. These coordination schemes are described as the result of choices made on multiple layers:

1. The needs (from which SO does the need of flexibility come from?)
2. The buyers (which stakeholders are going to be buyers in the flexibility market(s)?)
3. The market (how many flexibility markets are organized?)
4. Resource accessibility (does the TSO have access to flexibility resources connected to the DSO grid?)

Classification along these criteria results in seven groups of coordination schemes. The following table replicates the synthesis table presented in [9]. The table does not consider one of the seven approaches related to peer-to-peer markets, which is not within scope for the present study.

Table 1: A classification of T&D coordination schemes

Coordination scheme	NEED From which SO does the flex need(s) come from?	BUYER Who are the flexibility buyers?	# MARKETS How many flex markets are organized per bidding zone / area?	RESOURCES Does the TSO have access to DER?
Local Market Model	DSO need only	DSO	>1	/
Central Market Model	TSO need only	TSO	1	Yes or No
Common Market Model	DSO & TSO need	DSO & TSO	1	Yes
Multi-level Market Model			>1	Yes
Fragmented Market Model				No
Integrated Market Model		DSO, TSO & commercial parties	1	Yes

In a few words, the coordination schemes can be described as follows:

- In the *Local Market Model*, the DSO organizes a local flexibility market with the resources connected to its grid, with no cooperation with the TSO.
- In the *Central Market Model*, the TSO operates a flexibility market for all resources located at transmission and distribution level, with no or little involvement of the DSO (which can possibly be involved in some prequalification steps, if needed).
- In the *Common Market Model*, both the DSO and the TSO buy flexibility on one

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single market platform which centralizes all the flexibility bids and the network constraints from both SOs.

- The *Integrated Market Model* is similar to the previous scheme, except that commercial parties such as BRPs can also buy flexibility from the market, for instance in order to balance their portfolio.
- In the *Multi-level Market Model*, the DSO and the TSO are acting in separate markets in which the remaining flexibility bids accessible from the DSO are ultimately aggregated and offered to the TSO market.
- In the Fragmented Market Model, the DSO and the TSO are acting in separate markets. Distributed energy resources are not accessible by the TSO.

This report does not focus on developing additional alternative theoretical coordination schemes or conducting a further literature review for listing more coordination possibilities, but rather selects some of the proposed schemes and assesses their behaviors in the Norwegian context.

More specifically, in this study, we assume that (1) the DSO has the need for a flexibility market (in particular for resolving local congestion) and (2) that the TSO is also willing to gain access to the resources connected to the DSO grid (for both congestion management and balancing purposes), however without creating congestions in the DSO grids.

It is within this framework that TSO / DSO cooperation schemes need to be found. This means that, given the terminology introduced above, the "Local Market Model", the "Central Market Model" and the "Fragmented Market Model" are out of scope and that the study should look into the remaining three possibilities: the Common Market Model, the Integrated Market Model or the Multi-Level Market Model.

We underscore that, practically speaking, a key aspect of the cooperation between TSOs and DSOs is the exchange of data (even if aggregated, such as for example aggregated bids, aggregated interface setpoints, or network / "flow-based style" constraints). This can be a major limitation and a driving factor when deciding on the coordination scheme. In this study, we assume that the sharing of data between DSOs and the TSO in Norway is not the key concern (i.e., it is much more transparent than in other countries). Therefore, even if data sharing is an aspect to be discussed and kept in mind, it should not a priori result in discarding an approach such as the "Common Market Model".

6. Is there DSO-DSO cooperation for the organization of the flexibility market?

In [5], this criterion is described as "*DSOs using the same platform*". In the context of our current discussion, we interpret this criterion instead as requiring DSOs to communicate directly with each other (since in the context of the current project our understanding is that one single flexibility platform is being considered, as opposed to the co-existence of multiple platforms).

This topic is not further discussed in this study.

7. **What is the trading mechanism?**

   How is market trading organized? Is it organized as a closed-gate auction? Or does it function as a continuous trading platform?

   The base assumption is that the flexibility market is organized through a closed-gate auction, in order to be consistent with the MARI process.

8. **What is the market timeframe?**

   In which timeframe does the flexibility market take place, and how does the timing of this market interact with other energy markets? For instance, is the flexibility market taking place in DA, close to RT, etc.?

   The present study assumes that Statnett aims at keeping both balancing and congestion management close to real time, and consistent with the MARI timeframe. The process and order of events in the markets and their interactions with each other is clearly part of the analysis.

9. **What type of service is offered?**

   What is the purpose of the flexibility market? What is the "service" delivered by the market? Is the market used for congestion management, for balancing purposes, etc.?

   Our understanding is that we can assume that balancing and congestion management are performed jointly.

In summary, it is assumed that criteria 1 and 5 are the most important questions that this project studies, while criteria 7 and 8 have also been debated along the project.

2.2 Flexibility market setup

In order to make the previously listed criteria more concrete and to be able to make design choices for the rest of the study, we illustrate how a flexibility market can be organized with commercial and pilot use cases implemented during the last years. The purpose of the following section is also to illustrate how different contexts and needs can trigger different flexibility market designs. The sources for the following review are as follows:

- Information for GOPACS, NODES and Piclo Flex is based on [5]
- Information for Enera is based on the public description of the Enera flexibility market

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platform (Der enera Marktplatz für Flexibilitätshandel) and on [5]

- Information for Smartnet is based on [4] and the active participation of N-SIDE in the project
- Information for CoordiNet is based on the active participation of N-SIDE in the project
- Information for Cornwall Local Energy Market is based on [6]
- Information for Soteria is based on the active participation of N-SIDE in the project

2.2.1. Enera

Enera is a project funded by the German ministry of Economic Affairs and Energy. The Enera market platform is a joint project between TenneT (one of the German TSOs), Avacon Netz (DSO - mid-voltage), EWE NETZ (DSOs - low voltage) and the power exchange EPEX SPOT. The pilot is implemented in the Northwest of Germany (counties of Aurich, Friesland & Wittmund), which is a region with substantial oversupply in case of high wind infeed.

Enera's main objective has been to operate an exchange-based flexibility market for grid congestion management, thereby reducing the need for curtailment of renewable generation. The Enera Flexmarkt runs on a separate platform along with the intraday market. The platform facilitates market-based congestion management and is run by EPEX SPOT.

The Enera congestion management concept starts with a TSO-DSO grid coordination process, where the TSO and the DSOs exchange information related to (1) their own needs for flexibility and (2) the availability of flexibility towards the upstream and downstream system operator(s). The result of this process is a set of flexibility demands per market area, which are broadcasted to certified flexibility providers. A market area is a geographical area considered as being homogeneous from a grid congestion perspective. Certified flexibility providers are power plants, aggregators, VPPs, storage, renewables... which have successfully registered and are able to physically influence electrical flows from a given market area.

These flexibility providers are then invited to submit flexibility bids on the Enera market platform. The platform is in practice largely based on the design and technology of the German intraday market run by EPEX SPOT. Each bid has a quantity, a duration and a location. The bids can be continuously updated on the platform until they are matched by the system operators.

A matched bid leads to an obligation to modify an asset's schedule. Consequently, the BRP needs to rebalance its portfolio (typically but not mandatorily via the intraday market).

2.2.2. GOPACS

GOPACS is owned and operated by the Dutch TSO (TenneT) and four DSOs (Stedin, Liander, Enexis Groep and Westland Infra). GOPACS is not a market platform, i.e., no flexibility offers are cleared on GOPACS. Instead, it acts as an intermediary between the needs of network operators and market platforms. GOPACS is currently integrated with a Dutch flexibility / market platform named ETPA, and further expansions are envisaged.

The ETPA market platform operates as a regular intraday market (though without having access to cross-zonal capacity), where bids are geo-tagged. The transmission operators coordinate their needs for redispatch actions, and source these actions via the GOPACS mechanism by activating upward and downward bids at once. As each GOPACS transaction is composed of two legs, the market remains balanced.

2.2.3. NODES

NODES has been launched in Norway (Norflex) and Germany. Whereas in Norway the problem that is being addressed is downward flow to loads, in Germany the desire is to reduce curtailment of wind (i.e., to deal with upward flows). NODES is currently operated on a continuous basis as an intraday market.

Network operators source their flexibility offers on the same platform as BRPs. In NODES, there is an idea of forwarding flexibility offers which are not used locally to other market platforms, such as the cross-zonal intraday and balancing markets. This appears, for example, to be the case in the Norflex project.

2.2.4. Piclo Flex

Six DSOs in the UK are Piclo Flex members: UK Power Networks (UKPN), Scottish and Southern Electricity Networks, Electricity North West Limited, Northern Powergrid, SP Networks and Western Power Distribution. Piclo operates its own platform, Piclo Flex, which focuses on reservation. One of the key objectives of Piclo is to defer grid reinforcement investments.

Broadly speaking, Piclo Flex acts as a bulletin board, where DSOs post their customized and localized needs for flexibility (essentially a volume, a location, an up/down direction and a period plus some technical characteristics). Asset owners then respond to such "tenders", and submit their best availability and utilization prices for a given volume (possibly with some limitations, such as maximum utilization time). Granted offers consequently are made available to the DSO for congestion management at a later stage.

Note that Piclo operations are fully separated from the rest of the market operation.

2.2.5. Cornwall Local Energy Market with Centrica

Local Energy Market (LEM) is a local market project developed in the Cornwall region in the UK. The project includes Centrica, National Grid (TSO) and Western Power Distribution (DSO). Substantial amounts of decentralized wind farms have been installed in the Cornwall area in recent years. This has turned out to be problematic for the DSO, who seeks to secure grid constraints. The local flexibility market aims at enabling the DSO to contract flexibility for grid

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congestion management purposes. At the same time, the TSO is also able to buy decentralized flexibility from the market, which means that the TSO and DSOs are both flexibility buyers in this platform. Specific market rules are implemented to give the priority to the DSO bids in the market. For example, the TSO may not resort to an activation that contradicts the DSO activations.

LEM has no clear link to the UK congestion management processes at a national level. The Cornwall local energy market allows the trading of both reserve and energy under a closed-gate auction mechanism which is conducted both on a day-ahead and an intra-day basis and includes detailed network constraints of the DSO. Although the TSO is in principle also able to bid its own network constraints, so far only the DSO constraints have been taken into account in the market. In the scope of this pilot project, Centrica acts as a platform operator.

2.2.6. Soteria

Soteria is a local market that is being put in place by Fluvius (Belgian DSO) and Elia (Belgian TSO) under the IoE initiative launched by the Belgian system operator in 2019. Existing legislation in Belgium proposes a heuristic rule for enabling flexibility from the DSO grid to be used for balancing purposes, while preventing damaging activations for the DSO grid [7]. The rule limits the number of activations in a certain geographical perimeter: "in any circle with a radius of 100 m, there can be at maximum 10 connection points providing frequency control at any time" [7]. This rule turns out to be highly conservative in certain areas.

The market platform developed in the Soteria project aims at unlocking more residential flexibility from the DSO grid that can be used by the TSO for balancing, while respecting the DSO network constraints. The TSO is therefore the single buyer (the DSO does not buy flexibility), nevertheless the DSO inputs its network constraints into the platform. Soteria operates as a closed-gate auction. In the scope of this pilot project, N-SIDE was acting as the platform operator.

2.2.7. CoordiNet

CoordiNet is a European H2020 project centered around TSO / DSO coordination. The outline of the project is to design, run and assess three different demos (Spain, Sweden and Greece) which are testing various coordination schemes and market designs for multiple grid services: balancing, congestion management, voltage control and controlled islanding.

In the scope of this project, N-SIDE is developing a local congestion management market in Spain. The market is used in the region of Malaga, where some parts of the grid are tight because of power injections / withdrawals by decentralized energy resources.

The DSO, who is the sole buyer, bids its network constraints and flexibility needs in the market which is organized as a closed-gate auction in DA and ID. The TSO does not have access to the flexibility from the DSO grid, at least not through the local market. Nevertheless, the TSO organizes a separate market for solving its own congestions.

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2.2.8. SmartNet

SmartNet is an EU funded project in which N-SIDE was actively involved [4]. SmartNet proposes five coordination schemes which largely follow the categorization made in CoordiNet and described above. In particular, one of the schemes, named "*Decentralized common TSO-DSO*", implements the hierarchical design that we describe in further detail in the sequel, as it shares common characteristics with the hierarchical approach / aggregate BSP approach / A2 approach that was proposed in the first phase of the Statnett project. In the terminology introduced above, this design can be understood as a "multi-level market model", where the TSO can access the flexibility resources connected to the DSO.

In the sequel, wherever we refer to "Smartnet", it should be understood as the "Decentralized common TSO-DSO" approach described above.

The Smartnet hierarchical coordination scheme can effectively be integrated in the EU balancing market (e.g., MARI). However, in order to ensure consistency between pricing and resource activation, the Smartnet hierarchical platform also implements an additional disaggregation step in which locational prices (and corresponding settlements) are determined.

The hierarchical coordination scheme envisions TSO-DSO communication through the exchange of aggregate BSP offers (DSO to TSO) and aggregate positions (TSO to DSO). No direct communication between DSOs is required, provided that any individual feeder (i.e., the subnetwork under any TSO-DSO interface) is operated by a *unique* DSO[1]. As part of the MARI process, the hierarchical Smartnet approach does not require continuous trading.

The flexibility suppliers in the hierarchical Smartnet design are balancing service providers who can also be mobilized for congestion management (per the integrated balancing / congestion management approach that is adopted in Norway). Flexibility is procured by TSOs in order to balance the grid. The platform, by design, is implemented in such a way as to ensure that network constraints are automatically respected (if necessary, by out-of-merit activations, which are akin to skipping bids in the bid ladder).

2.3. Summary and conclusions

The following table provides a short overview of the different flexibility market projects and how they differ with respect to the criteria explained above.

[1] Note that this is not always the case. For example, in the Enera project, DSOs happen to be vertically connected. Namely, EWE NETZ is connected to Avacon Netz, which is in turn connected to the TSO TenneT DE [5].

Table 2: Classification of some key T&D coordination projects.

	Enera	GOPACS	NODES	PICLO	Cornwall	Soteria	Coordinet	Smartnet
Is the flexibility market integrated in existing EU markets?	X	V[1]	V[1]	X	X	V[1]	X/V	V[1]
Is the flex market operator a third party?	V	V	V	V	X	X	V	V
What is the TSO-DSO cooperation?	V (Fragmented Market Model)	V	V (Multi-level Market Model)	X	V (Common Market model)	V (Central Market Model)	V (Multi-level Market Model)	V (Multi-level Market Model)
Is there DSO-DSO cooperation	V	V	V	V	NA (only one DSO)	NA	NA	X
Is it continuous trading (C) or close-gate auction (A)?	C	C	C	A	A	A	A	A
Who is/are the buyer(s)	T&DSO	T&DSO[2]	T&DSO	DSO	T&DSO	TSO	DSO	T&DSO

1: by design possible, though not yet implemented
2: Peer-to-peer trading possible on the separate market platforms

From this benchmark analysis, the project team concluded to focus on the following specific topic:

How can resources connected in the DSO grid be made available to and activated by the TSO and forwarded to the European balancing platforms without causing new congestion problems.

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3. Perfect TSO/DSO Coordination and the Hierarchical Approach

3.1 Overview of Coordination Schemes, Test Cases and Assumptions

In this section we consider a number of TSO-DSO coordination scenarios which, although presented on simple illustrative examples, highlight a number of important issues related to the implementation of a coordination scheme that is compatible with the roles and responsibilities of different system stakeholders. The cases unfold in increasing complexity, and they are tackled first by an idealized perfect coordination benchmark. Although such a perfect coordination approach sets an efficiency benchmark, it would in principle require the implementation of a single market for clearing the entire chain of resources from the high-voltage grid down to the distribution system. The information and communication technology requirements as well as institutional barriers of such a coordination scheme are therefore overwhelming, and we instead consider a hierarchical alternative. The hierarchical alternative is motivated by the scalability, price consistency and institutional compatibility considerations that are described in the previous section, and we demonstrate through the examples of this section that it is, by construction, capable of reproducing the outcome of the perfect coordination.

As an alternative to the perfect coordination and hierarchical coordination approaches, we may consider an alternative settlement approach that are closer to existing practices. Such an approach may be considered as an interim coordination scheme that can bridge existing practices in certain systems to a future possible evolution to firmer coordination schemes through mechanisms such as the hierarchical TSO-DSO coordination. Such an approach also serves as a benchmark for highlighting and appreciating the differences in market clearing outcomes to a perfect TSO-DSO coordination (and its decentralized equivalent, the hierarchical TSO-DSO coordination scheme).

3.1.1 Description of the Perfect Coordination and Hierarchical Approach

We now proceed to describe the perfect coordination scheme and the hierarchical TSO-DSO coordination scheme.

Perfect TSO-DSO coordination. This model is rather theoretical and clears nodal prices. The model assumes that

(1) all information (including transmission and distribution level BSP offers, system imbalance, overloading of transmission and distribution network lines, and transmission and distribution network constraints) can be gathered in a central market clearing platform,

(2) the market clearing platform can solve a massive optimization within an acceptable time frame, and

(3) locational prices and individual dispatch instructions can be broadcast back to flexible resources. The approach tackles congestion and balancing simultaneously, and produces prices that are consistent with dispatch instructions.

The timeline of operations for the perfect coordination approach is presented in Figure 2. In step 1, the TSO and DSO submit their needs (e.g. imbalances) and grid constraints (e.g. in the sense of network constraints such as line capacities, flow-based constraints, and so on) to the flexibility platform. Similarly, BSP resources at both the transmission and distribution system submit their offers (in the form of bids for upward / downward activation of a certain quantity at a certain asking price to the platform. The common TSO/DSO market then clears in step 2, and in step 3 dispatch instructions are broadcast to BSPs at the transmission and distribution level. Prices are also broadcast to network operators for the purpose of settlement in step 3. By construction, the clearing is guaranteed to balance the system while respecting the network constraints of both the transmission as well as distribution system. Note that this coordination scheme treats transmission network operators symmetrically to distribution network operators (i.e. there is no notion of hierarchy) and the same applies for the symmetric treatment of BSP resources in the transmission and distribution system. As far as this coordination scheme is concerned, therefore, there is an identical treatment of transmission and distribution resources in the timeline of operations.

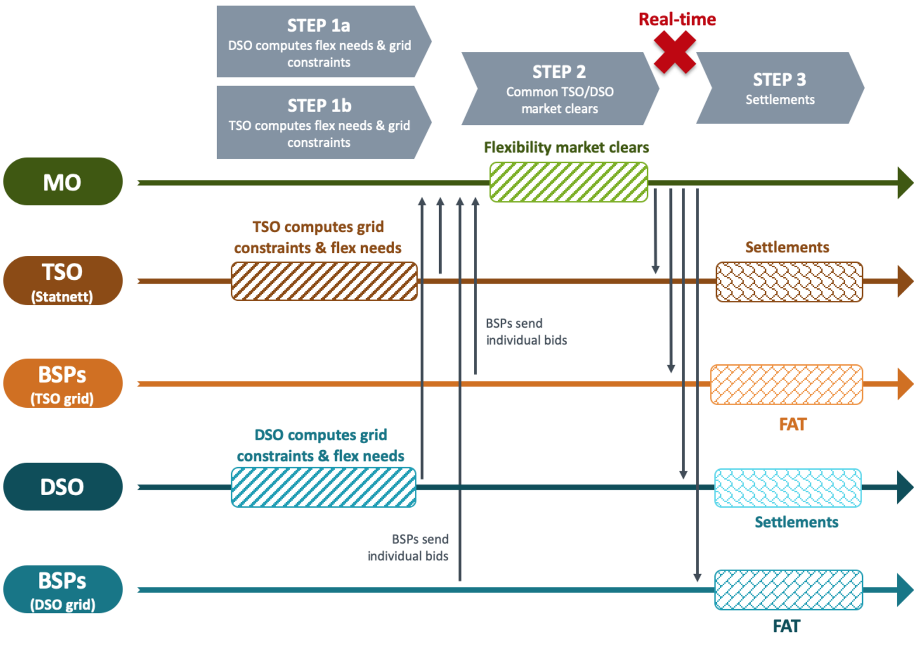

Figure 2: Timeline of perfect coordination.

The hierarchical TSO-DSO approach. The perfect coordination approach clearly places overwhelming communication and optimization requirements on TSO-DSO coordination, while

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also ignoring certain institutional boundary conditions, such as the fact that future balancing platforms shall not allow resources below a certain size to participate or will not account for transmission network constraints below a certain resolution. The hierarchical approach is designed in a way to overcome these barriers, by adopting a top-down approach whereby the system is optimized at different layers, with each layer being designed so as to be as close as possible to respecting the institutional and technological constraints of future TSO-DSO coordination, without sacrificing the optimality of the dispatch solution.

The timeline of the approach is presented in figure 3. The idea of the approach is that the full complexity of the distribution system is collapsed into a "residual supply function" (abbreviated RSF hereafter). Concretely, we introduce an "aggregation-disaggregation service" (abbreviated ADS hereafter) which collects the distribution network constrains of the DSO as well as the flexibility bids (offers for upward or downward activation at a certain price) of distribution-system BSPs in step 1 of the process. The ADS then computes a so-called RSF in step 2, which describes the least-cost way in which the distribution network operated by the ADS can deliver a certain aggregate upward or downward action at the point at which the distribution system in question is connected to the higher-level voltage network. This RSF is submitted to the TSO as a balancing market offer (i.e. a BSP bid of an "aggregate BSP" represented by the ADS), which can participate directly in the balancing auction on equal footing with transmission system BSPs which also place their bids to the balancing market in step 2. The balancing market then clears in step 3, and produces market clearing prices and dispatch instructions for transmission-system BSPs as well as an aggregate set-point for the ADS. Note that until this stage, the market clearing model is only guaranteed to respect transmission network constraints. In step 4, the ADS disaggregates the balancing market setpoint to distribution system dispatch instructions, and computes prices that are consistent with these dispatch instructions. In this disaggregation step, the distribution network constraints are represented explicitly, and the resulting dispatch is thus guaranteed to also respect distribution system constraints, i.e. it is guaranteed to deliver flexibility to the transmission network without causing distribution network violations. Then in step 5 settlements take place, based on the setpoints of individual BSPs at transmission and distribution level, and also based on the prices that are produced by the balancing market and the distribution system, and which have been broadcast to the TSO and DSO respectively.

Note that the only communication between the ADS and TSO in this coordination scheme is based on aggregate information: the RSF in the "bottom-up" direction (from the distribution to the transmission network), and the ADS setpoint and the balancing price at the location of the ADS in the "top-down" direction (from the transmission to the distribution network). This bottom-up / top-down structure earns the coordination scheme its name: it is by construction hierarchical. This is a decisive improvement in terms of scalability and institutional compatibility, relative to perfect coordination: the coordination scheme recognizes explicitly the fact that the TSO may not wish to access an overwhelming detail of distribution network information, and also that the DSO may not be willing to pass direct control to the TSO for its local resources or share its network

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information with the TSO.

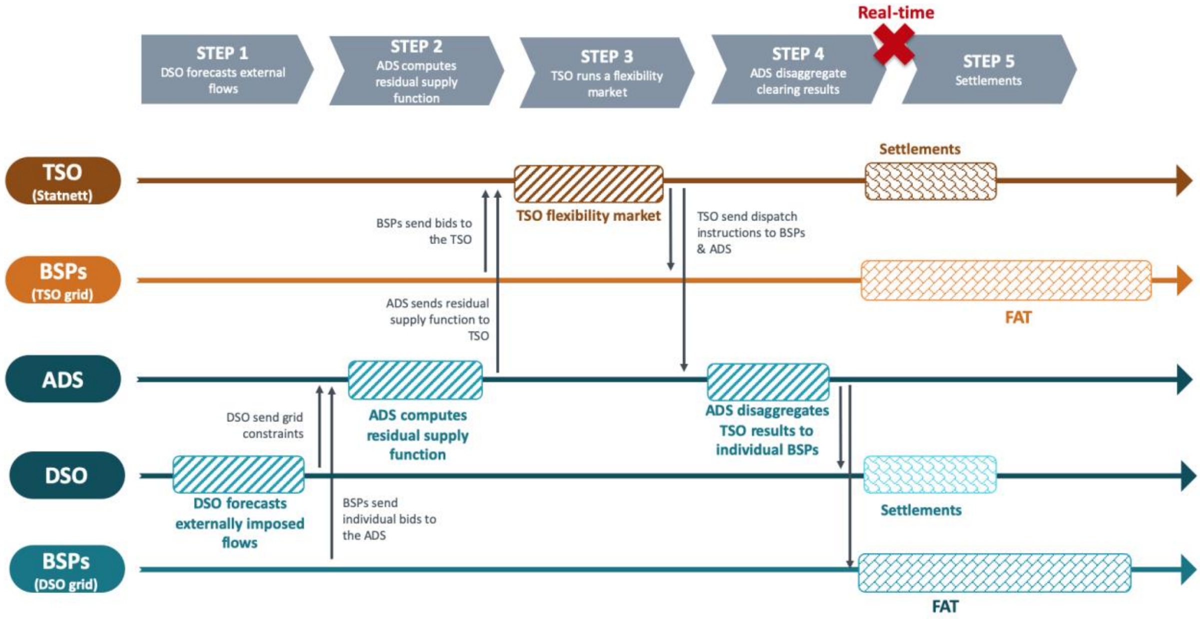

Figure 3: Timeline of hierarchical T&D coordination scheme.

We note that this innovative model has been proposed by N-SIDE for this study, but essentially relies on the same fundamental concept (the “residual flexibility supply curve”) as the previous Statnett study [2]. In the previous Statnett study [2], our team introduced the notion of a “Northern TSO” which was interacting with the rest of the system through an aggregation / disaggregation step. By analogy, the role of the aggregation / disaggregation is undertaken by the DSO in the context of TSO-DSO coordination (and then recursively by the TSO for the purpose of interfacing the TSO with MARI, as described in [2]). Figure 3 translates the timeline of approach “aggregated BSPs”, with the language adapted for the context of TSO-DSO coordination[2].

We note that the hierarchical approach has explicit connections to a number of TSO-DSO coordination projects that are cited in the previous section. Concretely, the “Decentralized Common TSO-DSO model” of the Smartnet project is exactly implemented as a hierarchical coordination scheme, with an explicit definition of a residual supply function.

3.1.2 Assumptions in Use-Cases

As we mention in the introduction of the present section, we exhibit the behavior of the different coordination schemes in a number of increasingly complex, yet illustrative, cases that highlight TSO-DSO coordination challenges. In order to develop these cases without any ambiguity, in what

[2] In practice, the residual supply function could take various forms and levels of sophistications, including a “bid filtering” approach. This is not the focus of the present study.

follows, we adopt the following assumptions:

- **Assumption 1 (measurable flows and network capacities)**: Flows on individual lines, whether they are in the distribution or transmission network, can be monitored. In general, this is true for medium-voltage grids in terms of both real and reactive power flows, but in the current analysis we ignore reactive power and focus only on real power flows. Combined with a knowledge of the capacity of each network element, this implies that the available margin on each network element can be quantified in real time. Violation of this assumption (e.g., not being able to observe violated constraints in real time) is considered as being out of scope for the purposes of the present analysis.
- **Assumption 2 (measurable system imbalance)**: There is a system-level indicator of system imbalance (e.g., frequency or modified / improved ACE) which implies a certain amount of balancing energy needed for the entire balancing area.
- **Assumption 3 (ex-post measurable nodal imbalance)**: Although we cannot measure, in real time, imbalances at the level of individual nodes, we can meter these values *after the fact* for the purpose of settlement. Such a nodal allocation of imbalance performed ex-post is only deemed possible - how it is precisely done is out of scope of the project. Note that this implies that all market participants must allocate (i.e., schedule) their positions at a granular level. Whether such an assumption is realistic needs to be assessed by Statnett. On the other hand, we note that there exist workable approximations of nodal pricing where loads are exposed to zonal prices, such as the ERCOT market.
- **Assumption 4 (measurable BSP availability / response)**: The availability of flexibility assets (referred to hereafter as BSPs) is known in advance of real time, and the response of these assets can be measured in real time. The exact location of these assets (down to the level of the individual node) is also known.
- **Assumption 5 (well-defined power transfer distribution factors)**: Each network element belongs to the perimeter of one, and only one, network operator (TSO or DSO). The same is true for each network node (whether high or medium voltage). For each network element within the perimeter of a given network operator, the implied flow on that network element resulting from a unit injection of power from a node within the perimeter of that network operator is known to that network operator (i.e. power transfer distribution factors are well-defined). The consequences of this assumption are discussed in Section 5
- **Assumption 6 (Single period and divisible bids only)**: For the sake of the following analysis, it is assumed that all BSP / BRP bids are fully divisible, and that the trading horizon is composed of only 1 period. Such an assumption is made in order to simplify the reasoning. The consequences of this assumption are discussed in Section 5.

3.1.3 Explored Use-Cases

In the following, we consider increasingly complex examples of TSO-DSO coordination. The

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sequence of examples can be described as follows:

- **Case 1**: *using a distribution system resource for balancing*. This case illustrates one of the simplest possible settings in which we have a non-trivial interaction between a TSO and DSO, namely a situation in which the transmission system operator utilizes a distribution system resource in order to balance the system, while having to respect a distribution network constraint.
- **Case 2**: *priority access to flexibility*. This case illustrates a situation in which the TSO and DSO have opposite interests in the activation of a distribution system resource: the TSO has an interest for upward activation, while the DSO has an interest for downward activation. The example sheds light on the discussion of priority access to a distributed resource.
- **Case 3**: *managing congestion locally*. This case illustrates the ability of the hierarchical approach to self-correct congestion within a distribution network.
- **Case 4**: *TSO and DSO are both in need of upward regulation. Who should pay for it*? In this example, the activation of a BSP in a given direction is beneficial both for the TSO (in terms of balancing the system) but also for the DSO (in terms of resolving a congestion). We then address the question of which of the two network operators should bear the cost of activating the BSP.
- **Case 5**: *interfacing with MARI*. This case discusses the interaction of the TSO with the MARI platform.

For each of the cases, we consider (i) the result of perfect coordination ("nodal-type" setup), (ii) the outcome of the hierarchical approach (i.e., "aggregated BSP" setup [2]). (iii) How settlement approaches that rely more on existing practices would resolve such cases is described in a separate section.

3.2 Case 1: Using a Distribution System Resource for Balancing

Let us consider a very basic scenario whereby an imbalance of -1 MW (power shortage) occurs in the transmission system. What we mean by "an imbalance occurs *in the transmission system*" is explained in the top panel of Figure 4: the system starts from a state where it is perfectly balanced, and all network constraints are respected. Subsequently, a BRP located in a transmission system node loses 1 MW of supply. In real time, it is not possible to identify which BRP induced this imbalance. It is only possible to measure this after the fact, for billing purposes (see assumption 3 in section 3.1.2). Instead, what is observable in real time, based on the assumptions stated above, is the state depicted in the lower panel of the figure (which is equivalent to the above panel from a physical viewpoint, but will matter in terms of the roles / responsibilities discussion below).

Note that we assume that all imbalances in the system are absorbed in the hub node, which we assume to be node T. Whether imbalances are "absorbed" by AGC, ACE, or remain in the slack / hub node is not important for the sake of this discussion. Thus, even after imbalance is absorbed, the D-N line is still loaded at the same level as before absorption. Note that in practical cases it is

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necessary to define how “imbalances absorptions” (i.e. AGC locations or ACE paths) are distributed in the network (which, to the best of our knowledge, is a reasonable assumption[3]). Simply stating that we can observe a frequency deviation and a pre-response measurement of the line flows is not enough to have a well-defined physical model, which means that we would not be able to formulate a meaningful balancing model, because we would not know what line flows are implied by different balancing actions. To be more specific, if in this example we would say that all we can measure is the short position of the system, and the pre-response capacity of 0.5 MW in the D-T direction, then we would have an ill-defined model. To see this, note that: (i) if the balancing action were absorbed in the distribution network, then activating BSP2 by 1 MW upward would imply no flow on the D-T line. (ii) if the balancing action were absorbed in the transmission network, then activating BSP2 by 1 MW upward would imply a flow of 1 MW over line D-T (and hence an overloading of the line). Therefore, simply stating that we can measure pre-imbalance flows and system imbalance is not enough, because the system is underdetermined. One way to arrive at a well-determined system is to also specify how AGC is allocated in different generators in the system (which effectively implies a re-distribution of the system balance to specific nodes in the network), and to measure the post-AGC flow on different network elements. The same reasoning holds for ACE-based approaches, where the inflows or outflows from the control area are specified. This essentially corresponds to assumption 5, which states that the injection of power from a BSP has a quantifiable impact on the flow of each network element.

In the scenario that is indicated in the figure, the imbalance can be cleared by cheap resources in the distribution system, or expensive resources in the transmission system.

[3] See, for example, Zhang, Yiling, Siqian Shen, and Johanna L. Mathieu. “Distributionally robust chance-constrained optimal power flow with uncertain renewables and uncertain reserves provided by loads”. IEEE Transactions on Power Systems 32.2 (2016): 1378-1388.

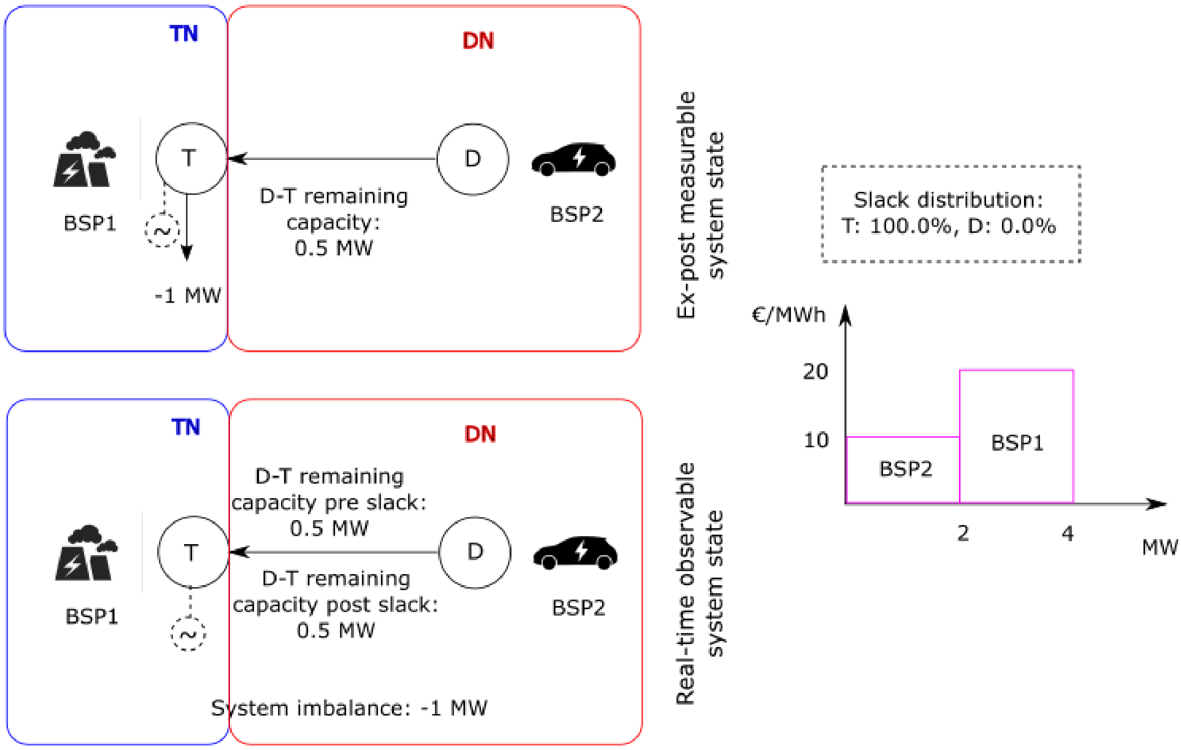

Figure 4: a simple imbalance scenario where an imbalance can be resolved by cheap flexible resources in the distribution grid, or more expensive flexible resources in the transmission grid.

The direction associated with the line in the figure is the reference direction of the line, which also indicates the direction of the actual physical flow for this example. Moreover, we indicate with a dashed line the slack generator. The distribution of the system slack is also indicated in the dashed box in the upper right of the figure.

To understand how we move from the upper panel to the lower panel of Figure 4, we first note what information is contained in each panel:

- In the upper panel, we can observe the flows on the network *before* imbalances occur (these are referred to in the upper panel as **flows pre-slack**), and imbalances that are caused by individual assets in *specific nodes* of the network. In real time this information is not necessarily observable, but it is the bottom-up information that is needed for defining the physical model (flows on individual branches and net injections on individual buses).
- In the lower panel, we can observe the imbalance at system level, as well as the flows on individual branches *after* the imbalances occurring in specific nodes have been absorbed by the slack bus (these are referred to in the upper panel as **flows post-slack**).

The way in which we move from the upper panel to the lower panel is by defining a mapping from the information in the upper panel to the information in the lower panel.

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(1) The first information that we need to determine for the lower panel is the imbalance at system level. For this purpose, we sum all the imbalances of the upper panel.

(2) We then need to compute the flow on lines *after* the system imbalance has been absorbed by the slack node. The way in which we compute this is by noticing that the imbalance which has occurred in the upper panel is fully absorbed by a slack resource which is located in the transmission level. Thus, the flow on the D-T line remains identical between the upper and the lower panel.

(3) Importantly (and this is the reason we get into this discussion in the first place), since the slack node has absorbed the imbalance of the upper panel, any BSP activation will be used for relieving the resource of the slack node. Thus, the PTDFs of the system are well-defined. Concretely, the PTDF from node D on line D-T is 1 (i.e. every MW that is injected in node D implies a flow on line D-T in the direction from D to T).

3.2.1 Perfect TSO-DSO coordination

A platform that perfectly coordinates TSO and DSO operations would collect bids from resources in all voltage levels of the grid (both transmission and distribution). The platform would also collect the necessary network data for populating a market clearing model, including distribution network data (as foreseen, e.g., by articles 5-7 of the GLDPM methodology under CACM [1]). The sequence of actions per stakeholder is detailed in the following figure, that can be compared with the hierarchical approach figure above.

The clearing price determined by an integrated platform would be the following:

- 10 €/MWh for the distribution system node,
- 20 €/MWh for the transmission network node,
- activation of 0.5 MW from BSP2
- activation of 0.5 MW from BSP 1

There is a congestion rent of 5 €, and we assume that this congestion rent is collected into a single account (indicated as "Grid" in the following table). The settlements are shown in the following table.

Table 3: The nodal pricing settlement for case 1

Nodal pricing	BSP1	BSP2	BRP	Grid
	+10 € (0,5 MW@20€/MW)	+5 € (0,5 MW@10€/MW)	-20 € (1 MW@20€/MW)	+5 € (0,5 MW @(20-10)€/MW)

Note that this table does not distinguish balancing from congestion management payments, since energy and network capacity are auctioned off simultaneously. The system operator (the DSO in this case, since the congested line belongs to the distribution network) collects a congestion rent of 5 €.

3.2.2 Hierarchical TSO-DSO coordination

The hierarchical approach would involve the construction of a residual supply function by an Aggregation / Disaggregation Service (ADS), as indicated in the following figure. The ADS collects bids from BSPs within the distribution network, and uses the latest metered flows and the information of the distribution network to construct a Residual Supply Function (RSF). In the case of the figure below, this residual supply function stops at 0.5 MW due to the limit of the distribution line.

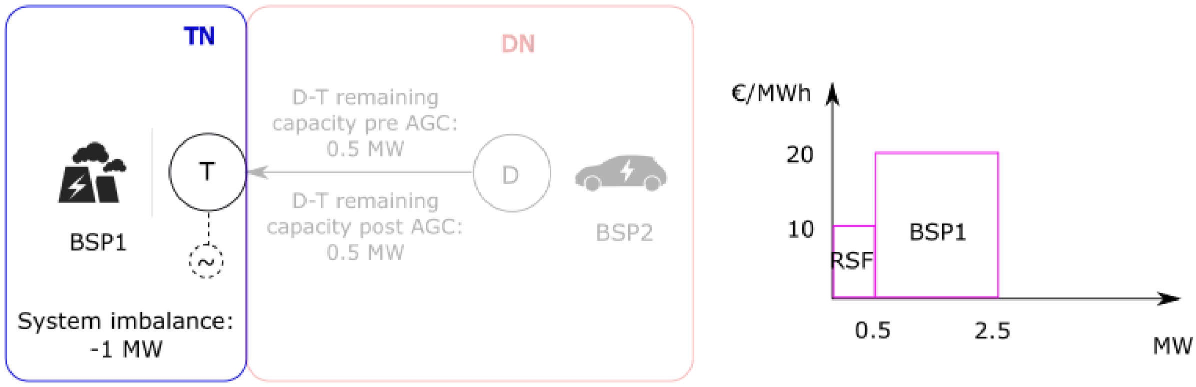

Figure 5: A hierarchical approach to TSO-DSO coordination, where an Aggregation / Disaggregation Service (ADS) computes a residual supply function (RSF).

The settlement steps are presented in the following table[4].

[4] Note, from the settlement table, that the net revenue collected by the ADS coincides with a congestion rent that would be collected by the distribution line. Concretely, the marginal cost in node D is 10 €/MWh, in node T it is 20 €/MWh, and the DSO receives the congestion rent of (0.5 MWh) x (20 €/MWh -10 €/MWh) = 5 €.

Table 4: Settlement in the hierarchical coordination of case 1.

Hierarchical approach	BSP1	BSP2	TSO	ADS	BRP
Balancing	+10 € (0,5 MW @20€/MW)	0 €	-20 € (1 MW @20€/MW)	+10 € (0,5 MW @20€/MW)	
ADS disaggregation		+5 € (0,5 MW @10€/MW)		-5 € (payment BSP2)	
Imbalance **(assuming imbalance price = balancing price)**			+20 € (0,5 MW @20€/MW)		-20 € (0,5 MW @20€/MW)
Total	+10 €	+5€	0 €	+5 €	-20 €

Using this residual supply function, a uniform price of 20 €/MWh is cleared in the balancing auction (for the transmission system zone). Subsequently, the ADS disaggregates the target setpoint of the balancing auction to its local resources. For this purpose, the ADS formulates a market clearing problem using the results of the balancing process as input. Concretely, the balancing auction indicates a value of 20 €/MWh for balancing energy at the location of the transmission-distribution interface[5]. In the disaggregation step of the ADS, the distribution network is now properly represented. This market clearing problem determines a price of 10 €/MWh for BSP2. Thus, the ADS collects 10 € from the balancing auction (and it can pay out 5 € to the BRP in an ex-post settlement, e.g., at the end of the month). The output of the balancing platform (in particular the quantity traded at the transmission-distribution interface) is used as input in the ADS, as indicated in the following figure. The disaggregation step is also assumed to have a good idea of how BSP activations at the transmission level would affect flows in the distribution level[6].

[5] There is a dual degeneracy issue in this step, we can elaborate on how this can be dealt with if needed. More specifically, when solving the disaggregation market clearing problem, in order to maintain a no-arbitrage condition for network prices, we should treat the target export as a demand valued at the balancing clearing result, instead of a fixed parameter (i.e., a demand of 0.5 MW of infinite valuation). This argument can be expanded if needed, but since the mathematical development is out of scope for this assignment, we do not elaborate further here.

[6] There is no contradiction between this statement and the fact that the ADS is receiving a target setpoint

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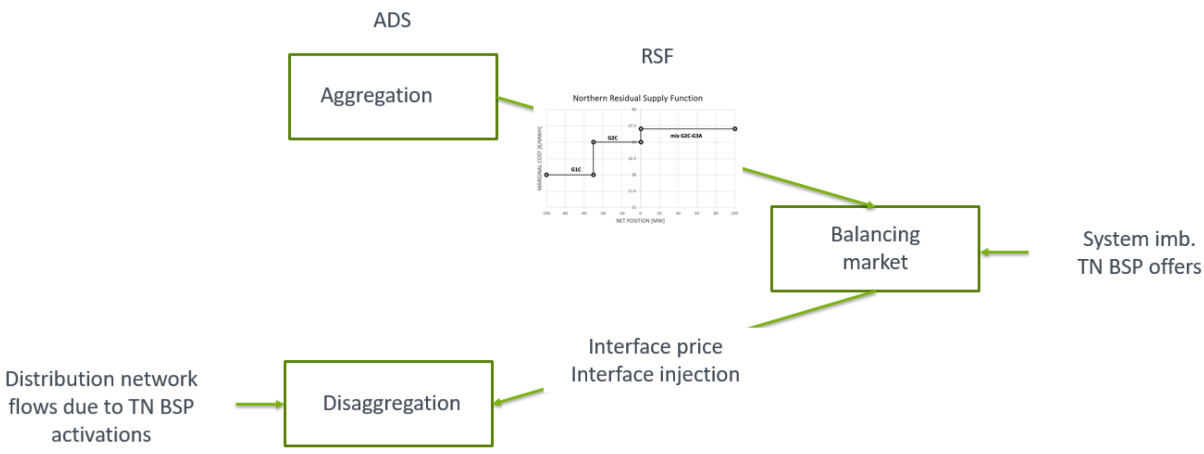

Figure 6: Data exchange between the ADS and the balancing market.

We now comment on the question of who has priority access to BSP2. Since the only network operator in need, in this situation, is the TSO, there is no question of who gets priority: the TSO needs the upward balancing energy of the low-cost BSP2, and gets access to it. The noteworthy aspect is that the ADS is designed in such a way as to ensure that this is achieved without violating the DSO constraints in the process. Moreover, the prices that are generated in the process are, to the extent possible, mitigating incentives for certain types of gaming behavior, as we discuss later in the report (see Section 5).

The current example can also be related to the discussion about priority access to flexibility. Concretely, the feasibility of the distribution network constraints comes at a higher priority than the balancing of the transmission grid at lower cost: although it would have been cheaper to source the full balancing response from BSP2, this balancing resource is only used partially, in order not to overload the distribution line. In later examples with a more intricate priority structure (e.g., with both TSOs and DSOs in need of a BSP response) we return to the discussion of which network operator has priority access to the flexibility.

3.3 Case 2: Priority Access to Flexibility

The next example that we would like to consider is one in which the TSO and DSO have contrary interests in the direction of activation of a flexible resource. For the hierarchical approach, we will show how coordination can be achieved between the TSO and the DSO without requiring the TSO to observe the congestion in the DSO system. Instead, this congestion will be resolved by the ADS.

Concretely, we would like to consider a scenario in which the TSO is interested in activating a

as input: the activation of BSP resources relieves the slack resources, and if some of the slack resources are located in the distribution network, this implies that distribution network flows are affected, even before distribution network balancing resources are activated.

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balancing resource upward (the grid total imbalance is -1 MW, due to BRPT being short by 1.5 MW and BRPD being long by 0.5 MW), whereas the DSO has a need to activate the flexibility resource downwards due to a congestion from the distribution to the transmission grid of 0.5 MW, as indicated in the scenario of the following figure.

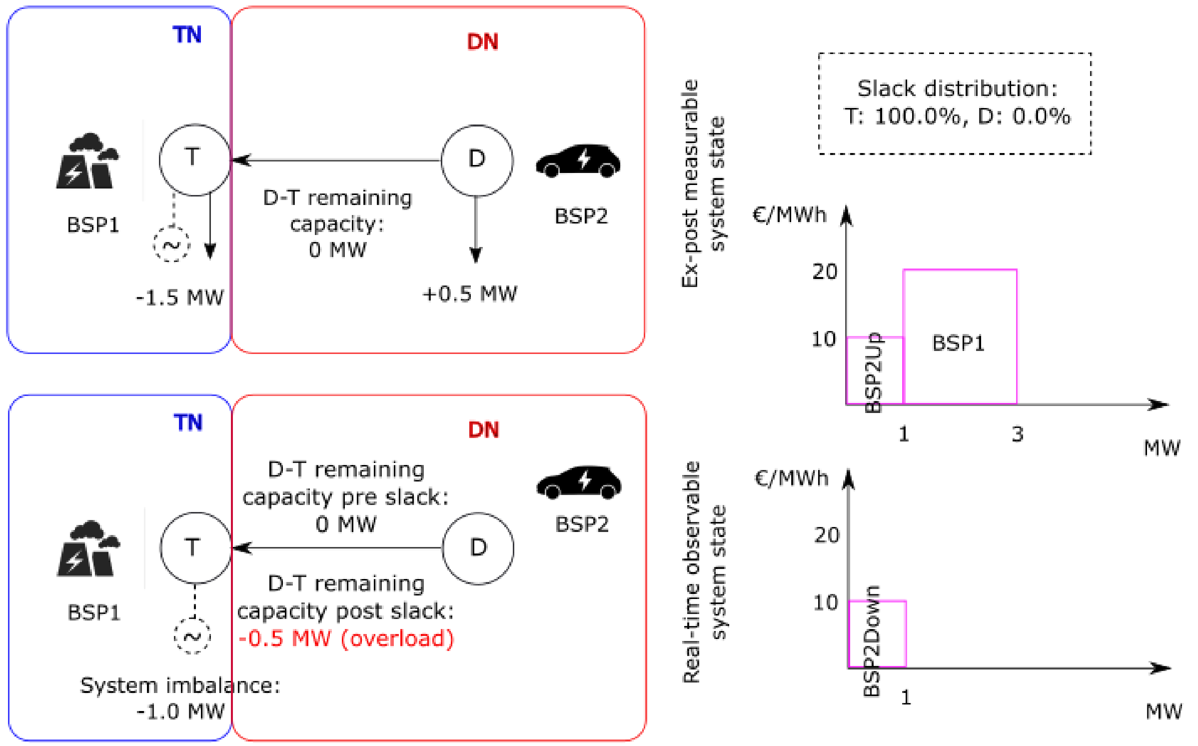

Figure 7: Case 2: a scenario which highlights how ADS tackles priority access to flexibility resources.

This scenario is very similar to case 1. Flexibility is located in both the transmission and the distribution network. The flexibility in the transmission network is for upward balancing, and is relatively expensive (2 MW @ 20 €/MWh). The flexibility in the distribution network is for both upward activation, and relatively cheap (1 MW @ 10 €/MWh) as well as for downward activation (1 MW @ 10 €/MWh). For example, this could be an electric vehicle battery that is partially charged, and could be charged or discharged at the same opportunity cost.

The direction associated with the line in the figure is the reference direction of the line, which also indicates the direction of the actual physical flow for this example. Moreover, we indicate with a dashed line the slack generator. The distribution of the system slack is also indicated in the dashed box in the upper right of the figure.

To understand how we move from the upper panel to the lower panel of the above figure, we first note what information is contained in each panel:

- In the upper panel, we can observe the flows on the network *before* imbalances occur

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(these are referred to in the upper panel as **flows pre-slack**), and imbalances that are caused by individual assets in *specific nodes* of the network.
- In the lower panel, we can observe the imbalance at system level, as well as the flows on individual branches *after* the imbalances occurring in specific nodes have been absorbed by the slack bus (these are referred to in the upper panel as **flows post-slack**).

The way in which we move from the upper panel to the lower panel is by defining a mapping from the information in the upper panel to the information in the lower panel.

(1) The first information that we need to determine for the lower panel is the imbalance at system level. For this purpose, we sum all the imbalances of the upper panel. The system is overall in a short position of -1 MW.

(2) We then need to compute the flow on lines *after* the system imbalance has been absorbed by the slack node. The way in which we compute this is by noticing that the imbalance which has occurred in the upper panel is fully absorbed by a slack resource which is located in the transmission level. Thus, the flow on the T-D line changes as a result of the slack resource in the transmission level, because part of the imbalance is occurring in the distribution grid. Concretely, if 0.5 MW of oversupply in the distribution system were to be absorbed by a slack resource located in the transmission system, then the post-slack flows on the line would result in a 0.5 MW overload from the distribution system to the transmission system.

(3) Importantly (and this is the reason we get into this discussion in the first place), since the slack node has absorbed the imbalance of the upper panel, any BSP activation will be used for relieving the resource of the slack node. Thus, the PTDFs of the system are well-defined. Concretely, the PTDF from node D on line D-T is 1 (i.e. every MW that is injected in node D implies a flow on line D-T in the direction from D to T).

In this scenario, there are conflicting interests for the use of BSP2. Since BSP2 is the cheapest resource in the system, the TSO has an interest in regulating it upward. On the other hand, since the distribution line is already congested, the DSO has an interest in dispatching BSP2 downward.

3.3.1 Perfect TSO-DSO coordination

The outcome of perfect coordination is as follows:

- 10 €/MWh for the distribution system node
- 20 €/MWh for the transmission network node
- Activation of 1.5 MW from BSP1
- Activation of -0.5 MW from BSP2

The distribution network imbalance is cleared locally by downward activation of BSP2, in order to prevent the line from being overloaded. In this sense, the priority of the DSO prevails, since using BSP2 for cheap balancing would result in a violation of distribution network constraints. The settlement under nodal pricing is described in the following table, where we indicate by BRPT the amount due by the entity that is in imbalance at the transmission level (metered ex post, according to assumption 2) and by BRPD the amount due by the entity that is located in the distribution system and is in imbalance (also metered ex post, according to assumption 2).

Table 5: the perfect coordination settlement for case 2.

Nodal pricing	BSP1	BSP2	BRPT	BRPD	Grid
	+30 € (1,5 MW @20€/MW)	-5 € (0,5 MW @10€/MW)	-30 € (1,5 MW @20€/MW)	+5 € (0,5 MW @10€/MW)	0 €

Note that the congestion revenues are zero despite the fact that the line is congested and despite the fact that there is a non-zero flow along the line. There is nothing contradictory about this, since we are presenting here the settlements in the balancing market, which adjust previous market positions: if no changes occur in the flows, the net change in congestion revenues is zero.

3.3.2 Hierarchical TSO-DSO coordination

The hierarchical approach produces the residual supply function that is derived by computing the minimum cost of evacuating power from the distribution system. We compute this cost using the following table.

Table 6: Total cost of evaluating power from the distribution network in the hierarchical approach.

Export (MW)	< -1	-1	-0.5	> -0.5
BSPBUp (MW)	0	0	0	0
BSPBDown (MW)		1	0.5	
Cost (€)	+Infinity (infeasible)	-10	-5	+Infinity (infeasible)

This produces the total and marginal cost shown in the following figure.

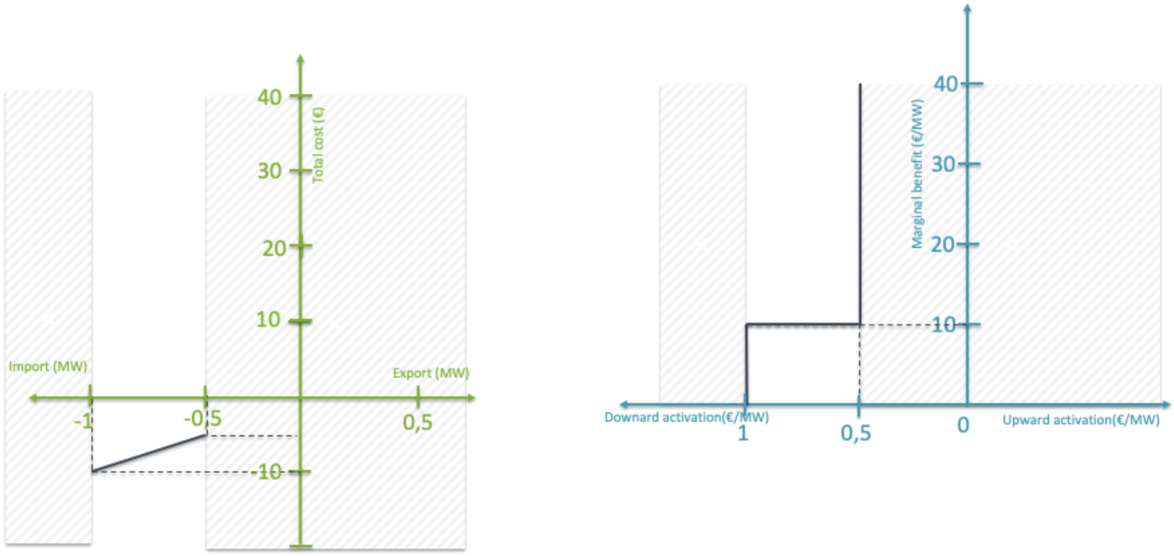

Figure 8: Total cost function (left) and residual supply function (right) in the hierarchical approach. These functions only have feasible values in the [-1, -0.5] range because the D area necessarily imports at least 0.5 MW to resolve the congestion

Thus, the hierarchical clearing can be depicted as follows.

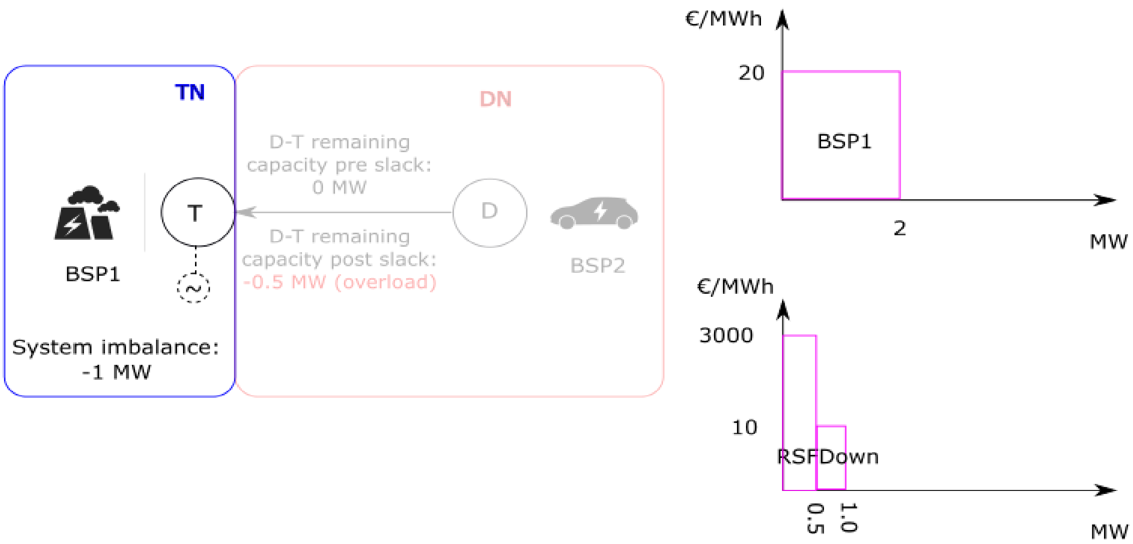

Figure 9: A hierarchical approach to TSO-DSO coordination for the conflicting activations of case 2.

The clearing of the balancing auction results in a transmission balancing price of 20 €/MWh, since BSP1 is marginal and sets the price at the transmission node. BSP1 is activated for 1.5 MW, in order to cover the demand of the distribution network, as well as the system imbalance caused by BRPT.

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Note that the aggregation function of the ADS has translated the congestion problem of the distribution system to a demand for balancing energy. Moreover, none of the upward balancing resources of the distribution system are represented by the RSF: the distribution network cannot export power without being overloaded (on the contrary, it must import at least 0.5MW). Indeed, this follows the pattern of the nodal pricing solution: distribution system security takes precedence over cheap balancing of the system.

Following the clearing of the balancing market, the ADS platform then takes over in order to disaggregate the net position of the distribution network to distribution system resources, and receives as input: (i) the system balancing price, and (ii) the net position of the aggregate distribution system BSP. The resulting price at the location of BSP2, computed at the disaggregation step, is 10 €/MWh, with BSP2 being activated downwards by 0.5 MW. **The outcome of the perfect coordination is thus replicated**.

Settlements are described in the following table.

Table 7: Settlements under the hierarchical coordination scheme.

Hierarchical approach	BSP1	BSP2	TSO	ADS	BRPT	BRPD
Balancing	+30 € (1,5 MW @20€/MW)	0 €	-20 € (1 MW @20€/MW)	-10 € (0,5 MW @20€/MW)		
Imbalance			+25€ (received from BRPT & BRPD)		-30€ (1.5 MW @20€/MW)	+5 € (0,5 MW @10€/MW)
ADS disaggregation		-5 € (0,5 MW @10€/MW)		+5 € (received from BSP2)		
Total	+30 €	-5 €	+5 €	-5 €	-30 €	+5 €

The overall settlement to the network operators is the sum of

- the BSP activations for balancing (in this case 30 € to BSP1, to activate +1.5 MW at 20 €/MW and -10 € from the ADS)
- the imbalance charges of the BRPs (in this case 30 € from BRPT and -5 € to BRPD, hence +25 € to the TSO)
- the remainder of the ADS after disaggregation (in this case 0.5 MW is settled at the local

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price of 10 €/MW towards BSP2)

- The total SO settlement is thus 0 €. The settlements coincide overall with those of the perfect coordination.

As in the case of perfect coordination, the hierarchical approach prioritizes distribution network security over access to cheaper balancing resources at the distribution grid.

One remark is worthwhile. According to a "disaggregated imbalance" interpretation (i.e. upper part of Figure 7), BSP1 covers the needs of BRP1, and there is essentially no exchange of power between the transmission and distribution system: 1.5 MW of BSP1 is activated in the transmission system in order to cover 1.5 MW of shortfall at the same voltage level, while 0.5 MW of BSP2 is activated downwards in order to cover 0.5 MW of oversupply at the same voltage level. According to an "aggregate imbalance" interpretation (i.e. bottom part of Figure 7), on the other hand, the transmission system is activating 1.5 MW of flexibility in order to cover a system imbalance of 1 MW, and the rest of the activation is made available for the distribution system (and procured through the RSF of the ADS). This point of view overlooks the fact that part of the overall system imbalance came from the distribution system in the first place, but this interpretation, to the best of our understanding, is more in line with the view of certain system operators on real-time observability in the system (i.e. a single system imbalance and line overloads are the only thing that is observable). Ultimately, no matter what the interpretation, the RSF is able to replicate the outcome of a perfect coordination while respecting the distributed management of information.

Side discussion on SO elasticity and willingness to pay to resolve a congestion

This example also illustrates another aspect of the RSF approach: DSOs are not required to bid explicitly for decongesting their grid, but rather can limit their involvement to the platform by submitting their network information (in this case a negative capacity) to the ADS. The ADS will then ensure that whatever dispatch of BSPs results from the process will be such that distribution network constraints are respected (i.e., the capacity returns to a non-negative value). This is in line with the fact that there is very little time left after MARI for further corrections, therefore it is of paramount importance for the DSO that whatever dispatch occurs in the platform is such that it does not violate distribution network constraints.

However, DSOs may desire to limit their price exposure and therefore bid explicitly their decongesting needs, including a price elasticity. This is relevant in case DSOs have other costly solutions that can be activated afterwards, and therefore do not want to procure redispatching "at any price". In practice, the SO may for this - when creating the RSF - replace the negative capacity by a penalty for congestion, such a penalty representing its "opportunity cost".

Building further on case 2, let us suppose a DSO price elasticity of 30€/MWh for not resolving

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the congestion (i.e., the DSO would like to resolve the congestion only if it costs at most 30 €/MWh). For example, this may represent the grid damage cost for temporarily allowing a flow above the conservative thermal limit, or a regulatory penalty for operating the grid outside certain limits. Since, in our example, the price differential between the 2 nodes is 10 €/MWh, the outcome is obviously the same because it costs less than 30 €/MWh to resolve the congestion.

The hierarchical approach produces the residual supply function that is derived by computing the minimum cost of evacuating power from the distribution system. We compute this cost using the following table. We now assume that we can violate the line limit at a cost of 30 €/MWh.

Table 8: Total cost of evacuating power from the distribution network in the hierarchical approach.

Export (MW)	**<-1**	**-1**	**-0.5**	**0.0**	**0.5**	**1.0**	**>1**
BSPUp (MW)		0	0	0	0.5	1	
BSPDown (MW)		1	0,5	0	0	0	
Line limit violation (MW)		0	0	0.5	1	1.5	
Cost (€)	+Infinity (infeas.)	-10	-5	15	35	55	+Infinity (infeas.)

This produces the total and marginal cost shown in the following figure.

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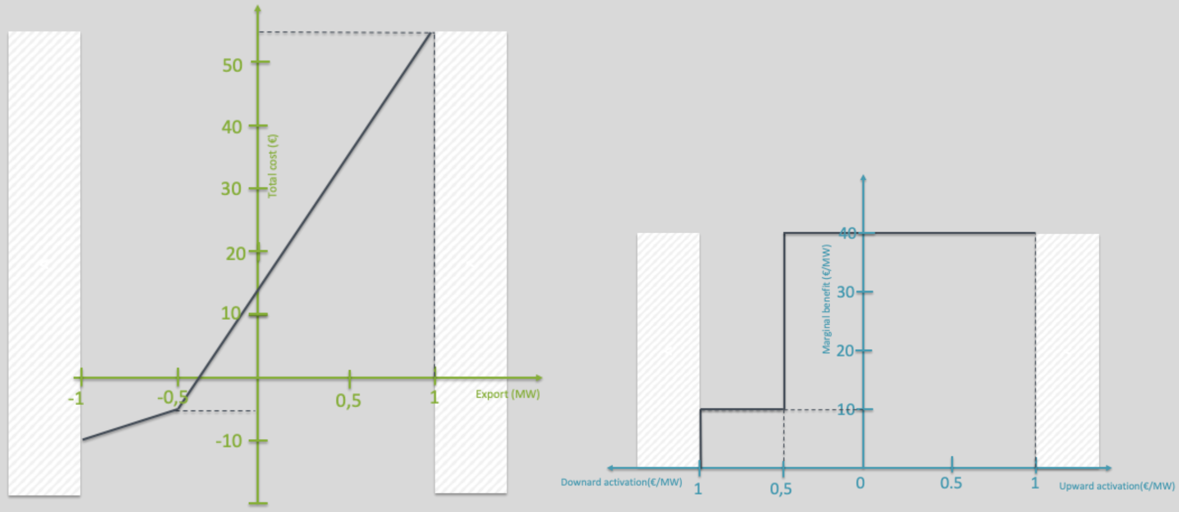

Figure 10: : Total cost function (left) and residual supply function (right) in the hierarchical approach, in case the DSO has a willingness to pay to resolve its congestion limited to 30 €/MWh. These functions now become feasible in the [-1, +1] range (which corresponds to any possible BSP2 activation), but – for the now available [-0.5, +1] range – the cost per MW increases by 40 €/MWh (for which 30 €/MWh are representing the DSO willingness to pay and the remainder the BSP2 bids).

Note that such an approach is rather versatile. For example, the DSO can determine a first tranche of congestion (i.e., flow above some limit) which is tolerable if it cannot be resolved at a low cost, a second tranche which is tolerable only if resolving it is very expensive, and the remainder that needs to be resolved at any price. However, “at any price” may become problematic in practical cases where the volume of BSP bids is insufficient, as it leads to infeasible solutions.

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3.4 Case 3: Managing Congestion Locally

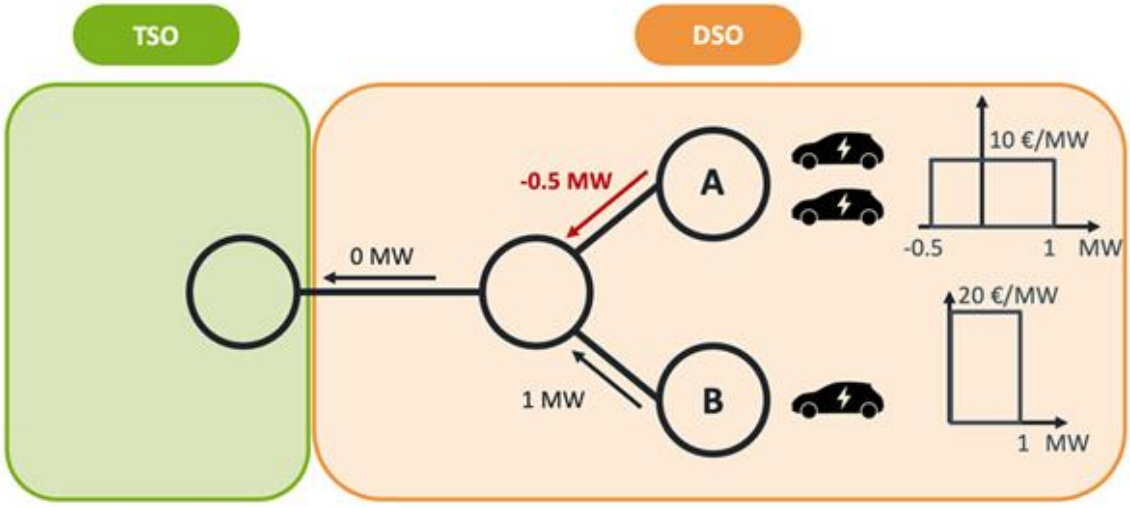

Figure 11: System settings in case 3.

The following scenario has been generated in order to understand how the hierarchical approach can handle congestion locally. In this example, there is no imbalance, so the TSO does not have any balancing needs. However, due to past markets that were not considering any grid constraints of the TSO and DSOs, the dispatch of the units on the DSO grid is such that the DSO is facing congestion. Here, congestion has the meaning that, according to the dispatch, the line will not simply be *tight* but *overloaded*: the usage of the line is 0.5 MW above its technical limit.

3.4.1 Perfect TSO-DSO coordination

The perfectly coordinated solution to this problem necessarily activates the BSP in node A downwards since this is required in order to decongest the line. Moreover, BSPB is activated upward[7] in order to rebalance the shortage caused by the downward regulation of BSPBA. Since the willingness to pay of BSPA for downward regulation is lower than the marginal cost of BSPB, the two resources are activated to the minimum extent that is required for resolving the congestion problem: BSPA is activated downward by 0.5 MW and BSPB is activated upward by 0.5 MW.

[7] One may wonder what would happen in this case if there are resources in both grids, but the transmission resource is cheaper. This scenario is essentially already sketched out in case 2 (where case 2 can be considered a simplified version of case 3, in the sense that node B is not shown in case 2, which boils down to the same outcome since the BSP in node B would not be selected)

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3.4.2 Hierarchical TSO-DSO coordination

In the context of the hierarchical approach, the idea is to first answer the question: what is the total cost of evacuating x MW from the distribution network? The answer is as follows:

Table 9: Tabular derivation of the residual supply function for case 3.

Export (MW)	**<0.5**	**-0.5**	**-0.4**	**-0.2**	**0**	**0.2**	**0.4**	**0.5**	**>0.5**
BSPAUp (MW)		0	0	0	0	0	0	0	
BSPADown (MW)		-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	
BSPB (MW)		0.0	0.1	0.3	0.5	0.7	0.9	1.0	
Cost (€)	+Infinity (infeas.)	-5	-3	1	5	9	13	15	+Infinity (infeas.)

The total cost function and resulting residual supply function are as follows:

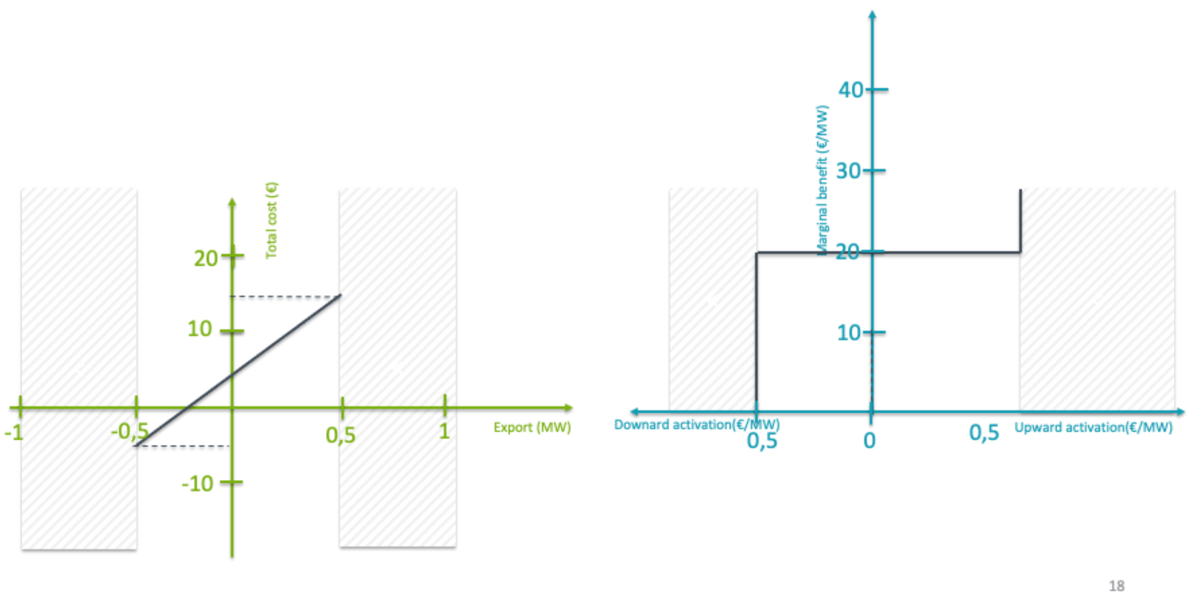

Figure 12: Graphical representation of residual supply function for case 3.

Thus, the RSF corresponds to two BSP bids, one upward and one downward. When submitted to the balancing market (which has no imbalance and no other BSP offers), we have a matching of 0 MW of the upward and downward RSF offers at a clearing price of 20 €/MWh. The balancing price is thus 20 €/MWh. The ADS pays 0 € to the balancing market, as it has exported / imported 0 MW.

The disaggregation system then determines locational prices and quantities that match the cleared balancing volume and price. The dispatch (primal) part of the disaggregation function computes what is the most efficient way to deliver the target export quantity, namely 0 MW. This can be achieved, from the lookup table above, by activating BSPB upward by 0.5 MW and BSPADown by -0.5 MW. The pricing (dual) part of the disaggregation system seeks prices that are consistent with the primal part and the root price of 20 €/MWh. Note that the price of 10 €/MWh in node A and 20 €/MWh in node B are consistent. To verify this, observe that the price / quantity pair is compatible with profit maximization for each BSP, as well as the network:

- Given a price of 20 €/MWh, BSPB is indifferent for any quantity of output since it makes zero profit margin, so the efficient dispatch of 0.5 MW is profit maximizing.
- Given a price of 10 €/MWh, BSPAUp and BSPADown are also indifferent, so the efficient dispatches of 0 MW and -0.5 MW respectively are profit maximizing.
- Given a price differential of 10 €/MWh between the middle node and node A, it is indeed anticipated that the line from the middle node to node A is used at its capacity limit, since the network operator earns a profit margin of 10 €/MWh for every unit that is transported from the middle node to node A.

In conclusion, the ADS pays 10 € to BSPB and is paid 5 € by BSPA, so on the aggregate the ADS faces a deficit of 5 €/MWh (this is not contradictory to standard theory that foresees a negative merchandising surplus, since the network starts from an infeasible dispatch). We can thus interpret the outcome as the ADS (i.e., the network operator, on behalf of whom the ADS is operating) resolving its congestion at a "cost" of 5 €. This reproduces, in a procedure that can be integrated to the balancing market operations and respect distributed information sharing between TSO and DSO, the (pricing and dispatch) outcome of a perfect coordination.

Note, also, that the DSO never explicitly submits "flexibility" bids. As in the case of the TSO in EUPHEMIA, it simply submits its network information to the platform. Through implicit auctioning of distribution network capacity, the platform ensures a market clearing outcome that maximizes the value of the use of the network (or, in this case, minimizing the cost of recovering it to a secure state). However, as discussed for case 2 above (see grey box in Section 3.3.2), it remains possible to adapt the ADS function so as to allow the system operators to provide explicitly such "flexibility bids".

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3.5 Case 4: TSO and DSO Activate for Upward Regulation: Who Pays?

Case 4a: imbalance exceeds congestion

In order to analyze this case, we consider a scenario in which there is an overload on the line from the transmission system down to the distribution system as well as a negative system imbalance. The situation is depicted in the figure below.

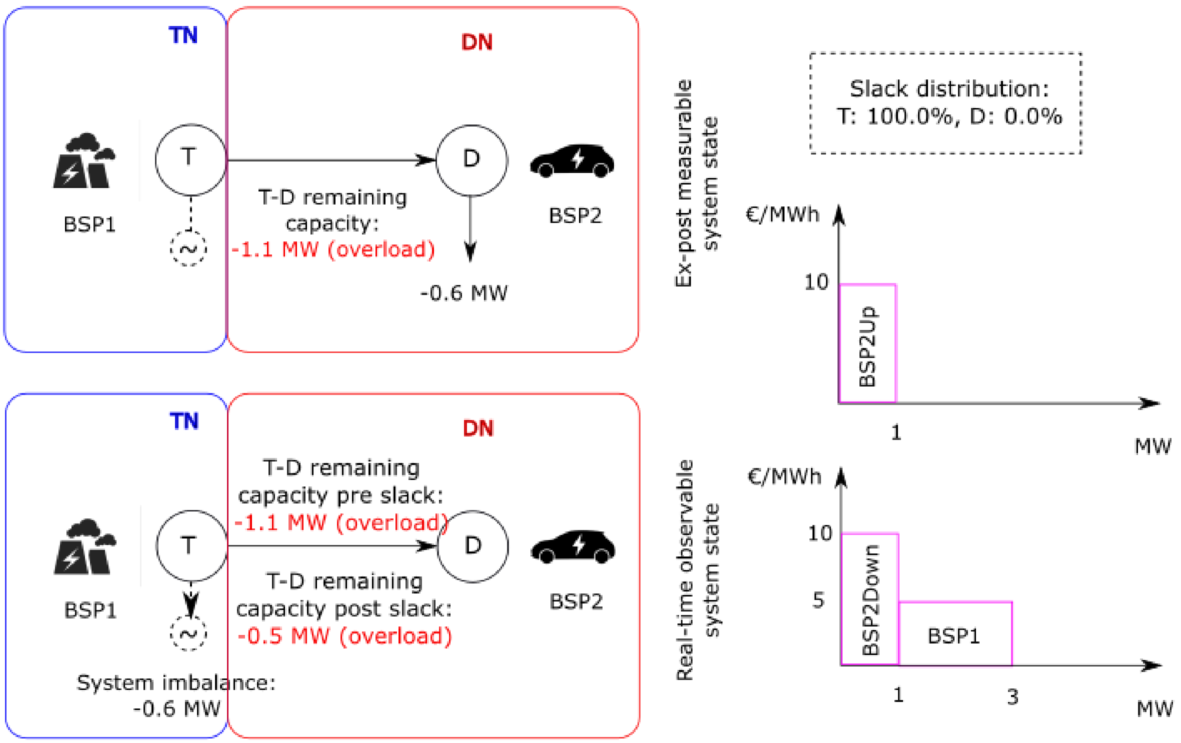

Figure 13: System settings in case 4a.

In order to understand how we transition from the top part of the figure (ex post measurable "flows pre-slack") to the lower part of the figure (real-time observable "flows post-slack"), we note that the imbalance caused by BSP2 is "absorbed" by the slack resource in the transmission network. Since the slack is located in the transmission network, the PTDF of node D on the line T-D is -1 (any power injected by BSP2 in D is absorbed by slack resources in T). In this use-case, the TSO seeks to resolve this imbalance in order to restore slack resources and prepare them for the next disturbance.

The case is interesting because on the one hand the system is short, so the TSO has an interest in activating balancing energy upward, but also the distribution line is congested, so the DSO also has an interest in activating upwards.

Case 4b: congestion exceeds imbalance

On the other hand, we may consider the following similar scenario, in which the system imbalance is less than the level of congestion on the line.

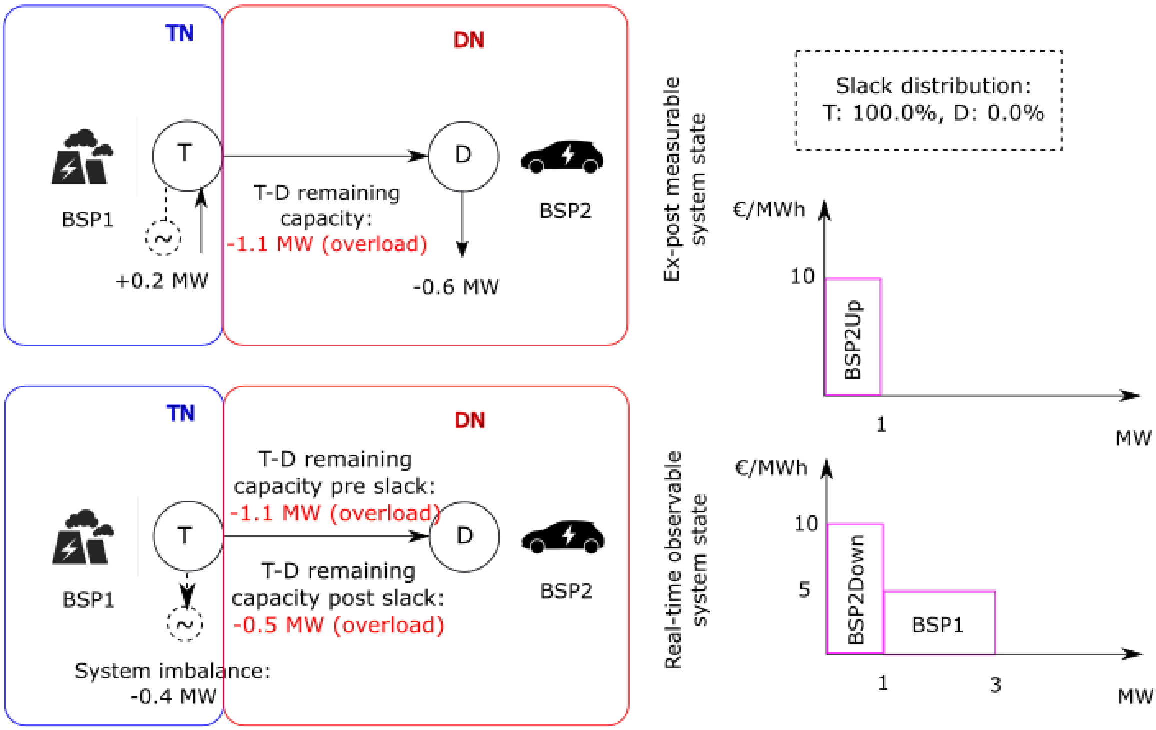

Figure 14: System settings in case 4b.

3.5.1 Perfect TSO-DSO coordination

Perfect coordination case 4a

In the case where the entire network is perfectly coordinated, TSO demands and BSP offers are collected to a single platform. We have an activation of BSP2 upwards by 0.6 MW in order to decongest the line and also balance the system, since BSP2 is the only upward flexibility resource in the system. BSP2 is marginal, and the line is uncongested, therefore a unique price of 10 €/MWh prevails in the entire system. Note that, as we show subsequently, the result coincides with that of the hierarchical T&D coordination approach.

Perfect coordination case 4b

Again, assuming that all network, flexibility (BSP) and TSO demand information is communicated to a single platform, we have an activation of BSP2 by 0.5 MW in order to decongest the line. BSP2 produces less than in case 4a, because the system only requires 0.4 MW of balancing, and the reason it is activated at 0.5 MW is in order to decongest the line. The price in node D is 10 €/MWh, since BSP2 is marginal, while the price in node T is 5 €/MWh, because BSP1 needs to be activated downward in order to absorb the excess supply of BSP2 which is needed for decongesting the line. Again, the result coincides with that of the hierarchical approach, as we show subsequently.

3.5.2 Hierarchical TSO-DSO coordination

Hierarchical coordination case 4a

We follow the same procedure as in the previous sections. Concretely, we derive the following table, which allows us to construct the residual supply function.

Table 10: Tabular derivation of the residual supply function for case 4a.

Export (MW)	<-1	-1.0	-0.5	0.0	0.5	1	>1
BSPBUp (MW)					0.5	1	
BSPBDown (MW)					0	0	
Cost (€)	+Infinity (infeas.)	+Infinity (infeas.)	+Infinity (infeas.)	+Infinity (infeas.)	5	10	+Infinity (infeas.)

The corresponding residual supply function is depicted below. The RSF consists of two segments. The price of the first segment is at the price floor for a quantity of 0.5 MW (i.e., “I am willing to *pay* a large amount to *produce*”, driven by the fact that the distribution line is congested). The second segment is at a price of 10 €/MWh for a quantity of 0.5 MW of upward activation. No downward activation is possible, given that the distribution line is already congested.

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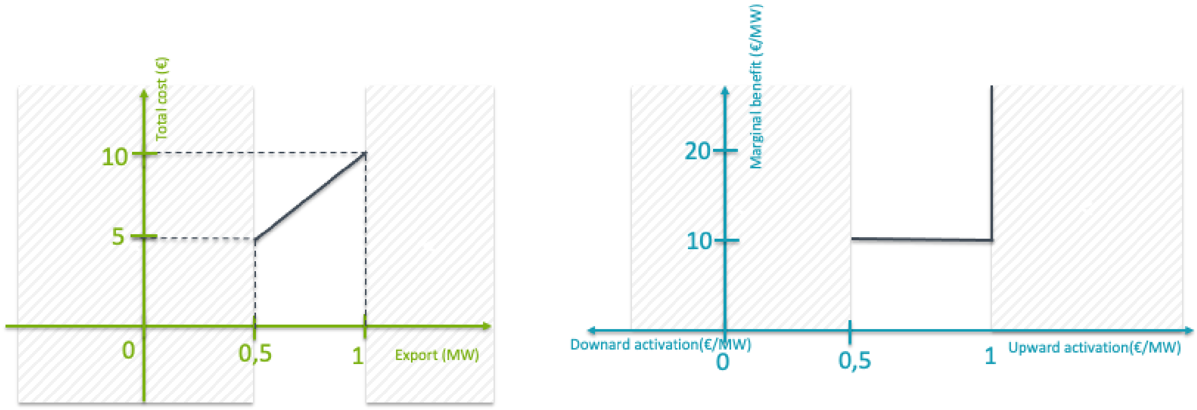

Figure 15: Graphical representation of residual supply function for case 4a and 4b.

In the balancing market, the system imbalance is matched against 0.6 MW of RSF. The resulting balancing price is 10 €/MWh, since RSF is marginal.

The primal/dispatch part of the disaggregation function then runs, with an aim of finding the most efficient way to evacuate 0.6 MW. The only way for this to be achieved is by activating BSP2 upward by 0.6 MW.

The dual/pricing part of the disaggregation function then runs, with an aim of determining prices that are coherent with the dispatch and the balancing price. Concretely, we arrive at a price of 10 €/MWh for the distribution system:

- This price is consistent with the partial activation of BSP2, which is indifferent about any quantity of activation, since it is making a zero-profit margin.
- The price is also consistent with the optimal utilization of the network: since there is no price differential along the two ends of the line, any flow along the line is value-maximizing.

The resulting settlements are reported in the following table.

Table 11: Settlements in case 4a.

Hierarchical approach	BSP1	BSP2	TSO	ADS	BRPD
Balancing	0 €	0 €	-6 €	+6 €	0 €

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Imbalance	0 €	0 €	+6 €	0 €	-6 €
ADS disaggregation	0 €	+6 €	0 €	-6 €	0 €
Total	0 €	+6 €	0 €	0 €	-6 €

From this table, ADS has a financial exposure of 0 €, thus the DSO is not paying for the congestion relief[8]. Note that we assume that BRP2 pays the price determined by the ADS for its location, which in general may be different from the balancing price (although it is not the case here).

Hierarchical coordination case 4b

In this case, the balancing price becomes 5 €/MWh. The orders that are accepted are (i) -0.4 MW of TSO demand, (ii) -0.1 MW of BSP1, and (iii) 0.5 MW of the RSF. The price is set by BSP1, which is marginal.

The primal/dispatch part of the disaggregation function then runs, with an aim of finding the most efficient way to evacuate 0.5 MW. The only way for this to be achieved is by activating BSP2 upward by 0.5 MW.

The dual/pricing part of the disaggregation function then runs, with an aim of determining prices that are coherent with the dispatch and the balancing price. Concretely, we arrive at a price of 10 €/MWh for node D:

- This price is consistent with the partial activation of BSP2, which is indifferent about any quantity of activation, since it is making a zero-profit margin.
- The price is also consistent with the optimal utilization of the network: since there is a price differential along the two ends of the line, the value-maximizing flow is at the capacity of the line from node D to node T.

The resulting settlements are reported in the following table.

[8] Note that this is consistent with current Statnett practice. If a system regulation "happens to become" a balancing action, it is treated as the latter.

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Table 12: Settlements in case 4b.

Hierarchical approach	BSP1	BSP2	TSO	ADS	BRPT	BRPD
Balancing	-0.5 € (-0.1MWh@5€/MWh	0 €	-2 € (-0.4MWh@5€/MWh	2.5 € (0.5MWh@5€/MWh	0 €	0 €
Imbalance	0 €	0 €	+2 € (0.4MWh@5€/MWh	0 €	+1 € (0.2MWh@5€/MWh	-3 € (-0.6MWh@5€/MWh
ADS disaggregation	0 €	+5 € (0.5MWh@10€/MWh	0 €	-5 € Settles BSP2	0 €	0 €
Total	-0.5 €	+5 €	0 €	-2.5 €	1 €	-3 €

In this case, the ADS produces a negative cash flow, which means that the DSO becomes financially liable.

Comparing cases 4a and 4b

- **In conclusion, the answer to the question that motivated case 4 (i.e., who pays?) is that "it depends": if the system imbalance exceeds the level of congestion, resulting in decongesting the initially congested line, then the DSO avoids any financial exposure. This is because the congestion is "coincidentally" resolved by merit order activation of balancing needs.**
- **If, on the other hand, the system imbalance results in an activation of distribution system resources which is not enough to decongest the line, then the DSO bears financial exposure.**

The following table summarizes the observations that can be derived from case 3.

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Table 13: Summary observations of the case where TSO and DSO both wish to activate a BSP for upward regulation.

Congestion in D-grid	**Consequence for ADS / DSO**
None	No financial exposure of ADS / DSO
Congestion occurs due to balancing activations	Balancing flow from lower price in D-grid to higher price in T-grid → ADS / DSO receives (balancing) congestion rent
Existing congestion in real time	i) Congestion "happens to be solved" by optimal balancing activations → no financial exposure of ADS / DSO (this typically corresponds to a special case) ii) D-resource with higher price than alternative T-resource activated, ADS / DSO pays for relieving congestion

3.6 Case 5: Interfacing with MARI

We now combine two of the previous T&D systems into a single balancing market that is coordinated through MARI. Concretely, let us consider the combination of case 1 and case 4a. The situation is depicted in the following figure.

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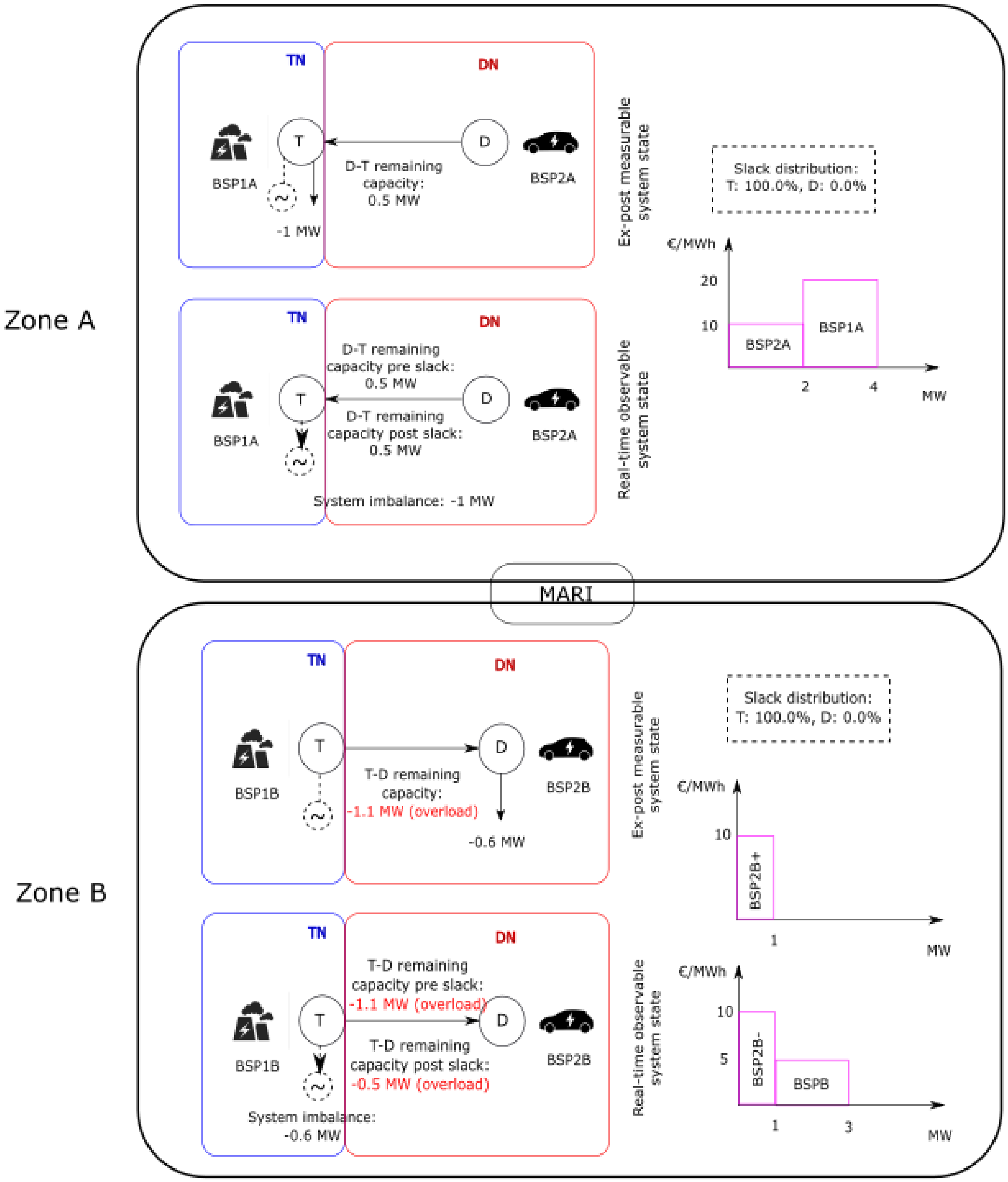

Figure 16: System setting for Case 5.

Zone A in the figure corresponds to case 1. Zone B in the figure corresponds to case 4a.

3.6.1 Perfect TSO-DSO coordination

Let us suppose that it is technologically feasible to communicate the entire information regarding the network of zones A and B, including the medium-voltage level, to a single clearing platform, that includes all TSO demands, and all BSP offers (at high and medium voltage levels). This is clearly impossible, but illustrates what would be needed for implementing a perfect coordination platform (and thus what the hierarchical approach avoids).

The system needs to source 1.6 MW of upward balancing energy, and to decongest the line of zone B. The second requirement implies that BSP2B+ must be activated upwards by at least 0.5 MW. This results in -1.1 MW that still need to be covered (the original imbalance of the two system is -1.6 MW), and one is indifferent between using BSP2A (but only up to 0.5 MW because of the line limit in zone A) and BSP2B+ (for another 0.5 MW, since that is the leftover capacity available in BSP2B+). Thus, another 0.1 MW has to still be sourced, and the last and most expensive option is BSP1A. Thus, the dispatch in the perfectly coordinated case is

- +1 MW for BSP2B+
- +0.1 MW for BSP1A
- +0.5 MW for BSP2A

The price at the transmission level (recall that we have assumed away transmission-level constraints) is set by the marginal resource, which is BSP1A, to 20 €/MWh. The price at the distribution node of zone A is set to 10 €/MWh by BSP2A, since BSP2A is marginal (i.e., producing a non-zero quantity below its maximum capacity). The price at the distribution node of zone B is 10 €/MWh, because BSP2B is also marginal, since the line cannot carry more output from this resource to the high-voltage network of the right system.

Note, as in the case of all previous examples, that the outcome coincides with that of the hierarchical approach. We show this in the subsequent discussion of the hierarchical approach. Note, however, that the communication requirements between the neighboring TSOs and their subordinate DSOs are fairly unrealistic in the perfectly coordinated case, since all information needs to be centralized into a single platform, an in principle enormous market clearing problem needs to be solved, and a significant number of dispatch instructions and local prices need to be communicated back to the network operators. It is this communication burden that a hierarchical approach overcomes.

3.6.2 Hierarchical TSO-DSO coordination

The process of generating residual supply functions has already been described in previous parts of the report. The residual supply functions of each distribution system are forwarded, along with the transmission-level BSP bids of each system and the TSO demands of each system, to the MARI platform. MARI thus receives the following bids in the hierarchical approach:

- TSOA (demand): Willing to pay 3000 €/MWh for 1 MW
- BSP1A (upward balancing): Asking 20 €/MWh for 2 MW
- RSFA (upward balancing): Asking 10 €/MWh for 0.5 MW

- TSOB (demand): Willing to pay 3000 €/MWh for 0.6 MW
- BSP1B (downward balancing): Willing to pay 5 €/MWh for 2 MW
- RSFB1 (upward balancing): Asking -3000 €/MWh for 0.5 MW
- RSFB2 (upward balancing): Asking 10 €/MWh for 0.5 MW

Note that we have ignored transmission-level constraints in these examples, in order to keep the exposition tractable and focus on how T&D coordination interacts with MARI. We have clarified how transmission-level constraints interact with the ADS of the TSO in the first phase of the project. The market offers are presented in the following figure.

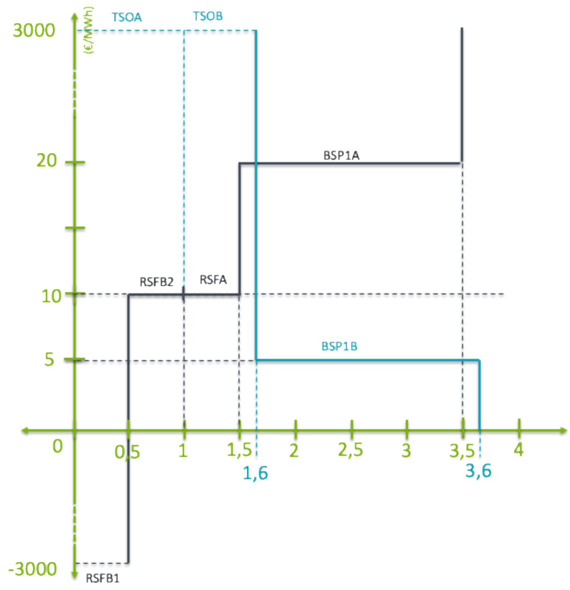

Figure 17: Bids arriving to the MARI platform in case 5.

Thus, MARI clears at 20 €/MWh with BSP1A being the marginal offer that sets the balancing price. The net position of the zones is as follows:

- Zone A has a net position of -0.5 MW (-1 MW for TSOA and +0.5 MW for RSFA).
- Zone B has a net position of +0.5 MW (+0.5 MW of RSFB1, +0.5 MW of RSFB2, +0.1 MW of BSP1B, and -0.6 MW of TSOB).

The financial transfers implied by the clearing of MARI are presented in the following table (NB: the settlement flows have been simplified, ignoring that MARI only settles towards TSOs in practice).

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Table 14: financial flows implied by MARI in case 5.

TSOA	TSOB	RSFB1	RSFB2	RSFA	BSP1A
-20 €	-12 €	10 €	10 €	10 €	2 €

The next step is for TSOs to disaggregate their net positions. Concretely, the primal / dispatch function of the TSOA ADS answers the question “what is the maximum-welfare dispatch by which I can deliver my MARI net position”? The answer for zone A is by activating RSFA by 0.5 MW, and the TSO demand by -1 MW. The dual/pricing function of the TSOA ADS answers the question “what is a price that is consistent with my target dispatch, as determined by the primal / dispatch function of the ADS”? The answer is 20 €/MWh. To see this, note that:

- TSOA is indeed willing to consume its full demand since its valuation exceeds the clearing price of 20 €/MWh.
- RSFA is indeed willing to produce its full output since its marginal cost is strictly below the clearing price of 20 €/MWh.

Subsequently, the ADS function of TSOA communicates the target export for the DSO of zone A, equal to 0.5 MW (the production expected from RSFA), and the TSO-DSO interface price of 20 €/MWh.

The ADS primal / dispatch function of the DSO of zone A runs next, by answering the question: “what is the lowest-cost way in which I can evacuate 0.5 MW?”. BSP2A is the only flexible resource at the DSO system, therefore the answer is by activating it by 0.5 MW. Note how the distribution network constraint is respected, as a result of the way in which the DSO ADS has constructed its residual supply function in the first place.

Finally, the ADS dual / pricing function of the DSO of zone A runs, by answering the question: “what price is consistent with the dispatch decision of the primal ADS and the interface price of 20 €/MWh”? The answer is 10 €/MWh, because:

- At this price, BSP2A is indeed indifferent for any quantity of output, since it makes a zero-profit margin.
- At this price, the maximum-value use of the network is to ship power from the distribution node to the transmission node, and this is consistent with the dispatch decision of using the distribution line at its limit.

An analogous procedure is executed by the ADS of TSOB, followed by the ADS of the DSO of zone

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B.

Note that the end effect is to replicate the outcome of perfect coordination, but with a minimal exchange of information: DSOs build balancing bids through the ADS aggregation function which guarantees that their local constraints are respected, without having to communicate their network information to their TSO or MARI. Instead, their network constraints are embedded in the form of the residual supply function. Similarly, the TSO does not communicate its internal nodal constraints to MARI, but rather can build an RSF that respects them automatically. This has been demonstrated in the first phase of the project, and is not repeated here in order to avoid obscuring the exposition, but the example can be generalized by introducing internal network constraints to the TSO networks.

One final important remark regarding the hierarchical approach is that it is modular. Concretely, the hierarchical approach can be adopted by a subset of DSOs, and does not require all DSOs to adopt it in order for the method to work.

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4. Gaming

4.1 Introduction

This section discusses the gaming opportunities for the envisaged models. The problem being solved by these models is to resolve local congestion within a zonal market design. Generally speaking, the problem at stake is thus inconsistent, because the locational incentive that should be given is by construction sub-zonal, hence not "allowed" by a zonal market design. As shown below, none of the alternatives are able to perfectly resolve this inconsistency of zonal market designs with internal congestions (only solutions directing towards nodal pricing would – though they suffer from other issues and are therefore not debated in this context).

4.2 Modified Case 1

To hold our discussion, we start by slightly modifying the example of case 1 in order to highlight certain gaming issues that may emerge when the settlement of a BSP is not aligned with the dispatch instructions of the market. Consider the situation depicted in the following figure.

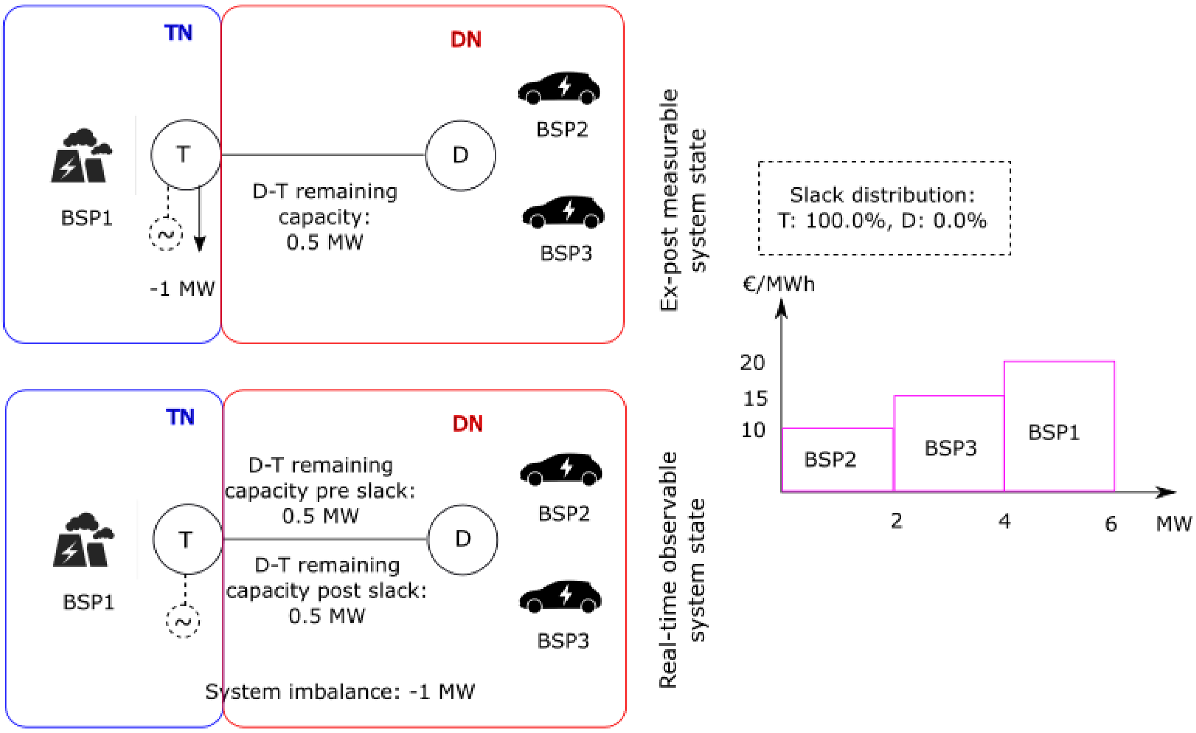

Figure 18: Modified version of case 1 in order to highlight potential gaming issues.

Compared to the original version of case 1, the only thing that has changed is that we have added a new resource, BSP3, which is offering 2 MW upward at 15 €/MWh. The resource is clearly inefficient compared to BSP2, and should not be dispatched.

4.3 Avoiding Local Balancing Prices

Consider a settlement approach that does not rely on local balancing prices. In such a case, BSP2 is selected as the cheapest resource at 10 €/MWh but for offering only 0.5 MW (as it is located behind a congested line), and is paid 20 €/MWh (i.e. the marginal price of BSP1 which has no grid constraints and therefore fills the remaining need for balancing energy).

This transmission price is misaligned with the fact that BSP2 is marginal, and this could potentially be problematic. Concretely, if BSP3 is aware that this settlement mechanism is employed, it can engage in a "price war" with BSP2, attempting to undercut it, since it can anticipate that the winning bidder will anyways be paid 20 €/MWh. Thus, the two resources will end up bidding at the floor of the flexibility market, and the TSO will be unable to tell them apart. But the two resources are *not* equally efficient, and the TSO *should* be able to tell them apart: BSP2 is 50% cheaper than BSP3.

4.4 Local Balancing: Hierarchical Approach

In the hierarchical approach, the ADS builds a residual supply function that consists of one RSF offer of 0.5 MW at 10 €/MWh, and the price settled at the distribution node is 10 €/MWh, not 20 €/MWh. Notice that the incentives for BSP3 to now engage in a "price war" with BSP2 vanish: if BSP3 undercuts BSP2, e.g., by offering 5 €/MWh to the ADS, then the RSF will be an offer of 0.5 MW at 5 €/MWh. In the disaggregation step, BSP3 will end up being settled for 5 €/MWh, which will result in the gaming strategy of BSP3 backfiring: if BSP3 tries to underbid below its true cost, it can end up winning the auction, and being dispatched at a loss. Thus, it will not undercut BSP2, and the TSO will indeed be able to tell BSP2 apart as the cheaper resource and efficiently select it for upward activation[9].

Note also that the proposed hierarchical approach settles imbalances at a locational price. This can be observed for case 2, where the imbalance of BRPD is settled at 10 €/MWh, while the imbalance of BRPT is settled at 20 €/MWh. This is also consistent as a principle, as it avoids another type of arbitrage. Indeed, suppose that BSP2 in case 2 can sell at an imbalance price that is different from the balancing price. If BSP2 can sell (via ADS activations) at a lower price than the price paid for imbalances, then the consortium BRPD+BSP2 has a strong incentive for INC-DEC gaming (i.e., inflate the positions of BRPD and BSP2 so as to increase the volume bought and sold at a price differential).

Importantly, settling some imbalances at a local imbalance price implies a potential significant paradigm shift for what concerns so-called "portfolio bidding", as it implies distinguishing the

[9] Nevertheless, note that BSP2 remains with an incentive to inflate its bid price to "just below" 15 €/MWh instead of 10 €/MWh. This relates to a lack of competition which cannot be resolved anyway.

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positions of each BRP at a very granular level. It thus is no longer possible to pool all the physical positions into a single portfolio.

Furthermore, when the day-ahead market is organized based on zonal prices whereas the balancing market produces nodal prices, this inconsistency produces INC-DEC gaming opportunities. Indeed, if the local balancing activations and imbalance positions for assets in congested areas are settled at different prices from the day-ahead prices, then a market party who correctly anticipates such congestion is able to arbitrage against the bulk market prices. For example, assets sitting in deficit areas have an interest to buy too much energy in the day-ahead market, as they expect to settle the resulting imbalances at high prices (presumably higher than the day-ahead prices if the deficit is severe locally). Such a behavior would not only create windfall profits, but also aggravate the expected congestion (because the expected load within the deficit area becomes larger) and thereby the congestion management cost. See Oren [13], Alaywan [14], Hogan [15], Hirth 2019 [16], Hirth 2020 [17] for extensive discussions on these topics.

4.5 Interim Conclusions

As introduced already, a zonal market design with internal congestions (whether at distribution or transmission grid level) leads to a fundamental grid modelling inconsistency which cannot be entirely resolved by settlement mechanisms. Indeed, by construction a zonal design settles all the assets participating to the bulk market[10] at a uniform price. If this uniform price leads to within-zone congestions, then some assets need alternative settlements (compared to the bulk market price) to resolve the congestion. Consequently, some assets become subject to two different prices (the one from the bulk market and the one to resolve the congestion), and thereby become able to apply INC-DEC gaming strategies (see [16,17] for a comprehensive description of this issue).

Although this issue cannot fully vanish, there are however settlement designs which are more appropriate than others. Based on the simple example above, we conclude that a marginal local balancing price (i.e. BSPs get a different price depending on their location) is likely necessary, preferably if imbalance prices can also be set locally. This is particularly relevant when balancing and congestion management are combined. Maintaining a different settlement scheme depending on the activation purpose (i.e. paid-as-cleared for balancing and paid-as-bid for congestion management) as a way to avoid INC-DEC gaming (in line with the currently applied paid-as-cleared for balancing and cost-based paid-as-bid for "special regulation") deserves further investigations. Importantly, the hierarchical approach allows one to adapt the settlement principles rather easily.

[10] By bulk market, we refer in general to either day-ahead, intraday or balancing markets. Although these markets may have different prices, such differences are due to different timings, but can evolve coherently within a zone as a consequence of evolutions of offer and demand.

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5. Limitations of the Hierarchical Approach

The hierarchical approach approximates a Benders decomposition algorithm from an algorithmic point of view, and is therefore guaranteed to reproduce the result of a perfectly coordinated T&D platform if the RSF is approximated at a sufficient number of points. The goal of the decomposition is to tackle the problems of scalability, communication complexity, algorithmic complexity, security, and institutional barriers of a perfectly coordinated T&D platform. Nevertheless, the guarantee that the hierarchical approach produces the optimal solution only holds when a certain set of assumptions hold. If these assumptions are violated, then one can expect a certain degree of suboptimality in the performance of the hierarchical approach. We discuss situations in which such deviations can occur.

5.1 Block Orders

If the orders that are placed in the market can be of the block type (i.e., with all-or-nothing or minimal output constraints) then the overall problem is no longer convex, and therefore decomposing it may yield suboptimal results. Concretely, if distribution system resources can offer block orders (take-it-or-leave-it offers), then the minimum cost at which we can evacuate a certain amount of power from the distribution feeder is no longer a convex function of the quantity of evacuated power. This implies that the derivative of this total cost function, which is the residual supply function, is no longer necessarily increasing, and may even be undefined (infinite) at points where the total cost function exhibits jumps. This issue is illustrated conceptually in the following figure.

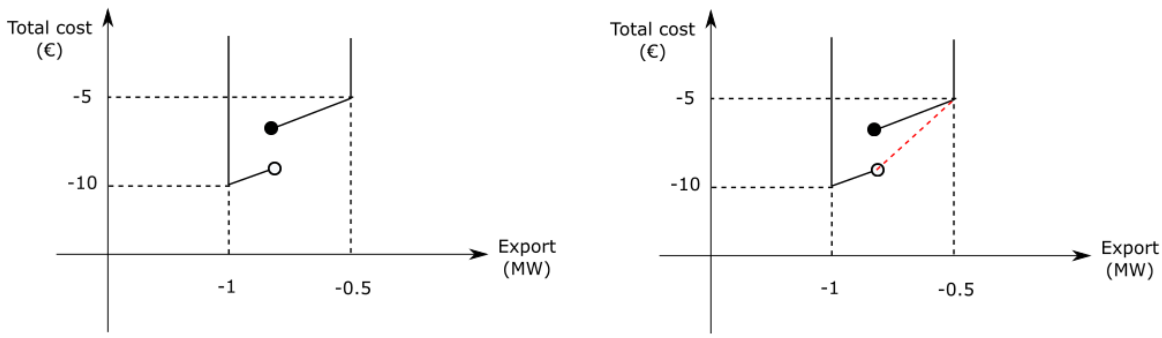

Figure 19: Total cost functions can be non-convex when the market has block orders (left panel). In such circumstances, we can work with the convex hull of the total cost function, indicated in dashed red, which in certain cases can be computed efficiently (right panel)

To tackle this issue, we can attempt to obtain the convex hull of the total cost function, and in this case its derivative indeed yields a residual supply function which is increasing. The advantage of this approach is twofold: (i) we have well-understood methods for deriving the convex hull of a non-convex function. (ii) The convex hull is the closest possible approximation of the true cost function which is still convex. We highlight however that the hierarchical approach no longer has optimality guaranteed. Empirically, nevertheless, our past work has indicated that the effect of this inaccuracy may not be significant [11].

5.2 Non-Radial Networks

In non-radial networks, the total cost functions that we use for building the residual supply functions are multi-dimensional: one dimension for the flow along each link that connects the distribution to the transmission system. Aiming at a specific export pattern (i.e., "10 MW of flow on TSO-DSO link A and 20 MW of flow on TSO-DSO link B") is more complex than aiming at a specific total net export (30 MW of export). This is an issue that has also been discussed in relation to a previous assignment [2].

All we can say at this point is that in such situations the hierarchical approach loses its optimality guarantees. The extent to which this effect is significant is still unclear, and will be studied in the follow-up of [2]. In a nutshell, this follow up relies on two principal ideas for tackling the issue of meshed networks: (i) either we construct the full total cost function and then project it to what we consider the most likely export configuration, or (ii) ignore the multidimensional nature of the total cost function and take a best-case estimation approach, i.e., compute the least-cost way in which we can evacuate power from a distribution network, *regardless* of the implied flows on individual lines.

5.3 Multiple Time Periods

In multi-period market clearing platforms, such as US-style multi-interval real-time markets [12], the total cost function is again multi-period, with each dimension now corresponding to a time step. The same issues emerge as in the previous paragraph: we cannot bid multi-dimensional residual supply functions to the balancing market, so we need to approximate the total cost function along (i) the most optimistic configuration, or (ii) the most likely configuration. We have observed from experiments on certain SmartNet test instances (e.g., the Italian test cases) that this effect is minor, while for other instances (e.g., Danish test cases) it can be significant. Therefore, as in the case of radial networks, all we can say at this point is that in such situations the hierarchical approach loses its optimality guarantees. The extent to which this effect is significant is still unclear. Nevertheless, this theoretical limitation may possibly not be of concern in the present context, as e.g. MARI only accounts for one period at a time.

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6. Alternative DSO settlement rules

In this section we look closer into settlement challenges if DSOs activate flexibility in a market-based solution to handle grid congestions. Today, DSOs have different possibilities to solve such constraints, but a market solution for flexibility is not yet an alternative. Most existing European market designs do not address how imbalances caused by flexibility activated by DSOs should be handled, and we will see that it is not a straightforward answer to this question. Even though the discussion is based on certain aspects of the Norwegian design, it is expected to be valid on a more general basis.

To illustrate the challenges, we go back to case 2 and explore how it will be solved with existing settlement rules and pricing. In the sequel we assume that the balancing market is settled at marginal price (clearing price) and that the imbalance price is the same as the clearing price in the balancing market. As previously stated, TSO activations will trigger imbalance adjustments according with present practice.

6.1 Revisiting case 1

The following table depicts how an alternative settlement approach could settle this case, which is recalled in the following figure.

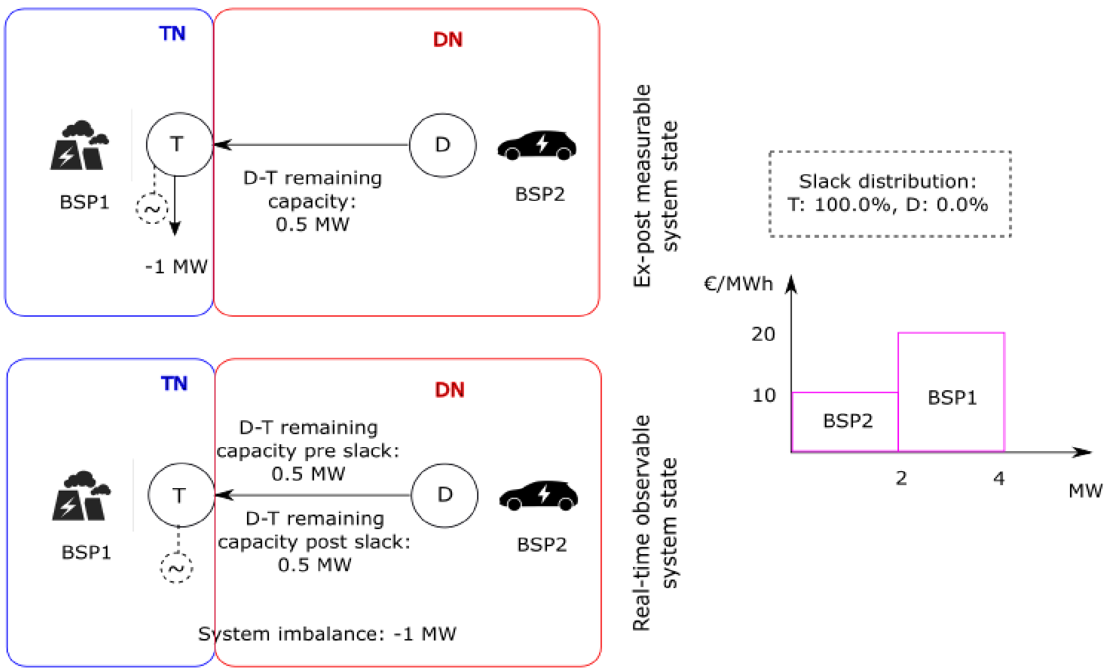

Figure 20: Recalling case 1.

Existing settlement rules are assumed: hereunder the balancing market is settled at marginal

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price (cleared price) and the imbalance price is the same as the cleared price in the balancing market. As it is assumed that all bids can be partly filtered, BSP2 bid is curtailed to 0.5 MW before being made accessible to the TSO. This bid is the cheapest available at 10 €/MWh and is therefore selected first to resolve the imbalance, for all the volume that has been made available to the TSO (i.e., for 0.5MW). The remaining imbalance of 0.5MW is resolved by the second best bid of BSP1 bid at 20 €/MWh. This leads to a balancing clearing price of 20 €/MWh, which implies that both BSPs are settled at 0.5MWhx20€/MWh = 10 €.

As the activations of BSP1 and BSP2 are triggered by imbalances / by the TSO, their portfolios are adjusted and no imbalances charges are applied to these parties. The 3rd party BRP causing the imbalance of 1 MW is settled for its imbalance (the imbalance price is presumably 20 €/MWh)

The portion of BSP2 that has been curtailed due to the DSO congestion is not compensated (even though this bid is price compatible in its entirety, only the "feasible part" is activated and remunerated. The BSP2 bid is therefore also not considered marginal). Consequently, no grid congestion revenue is collected.

Table 15: Settlement of an alternative approach for case 1.

Current approach (special regulation)	BSP1	BSP2	BRP	Grid
Balancing	+10 € (0,5 MW@20€/MW)	+10 € (0,5 MW@20€/MW)	-20 € (1 MW@20€/MW)	0 €
Special regulation				
Total	+10 €	+10 €	-20 €	0 €

6.2 Revisiting case 2

In the following figure we recall case 2.

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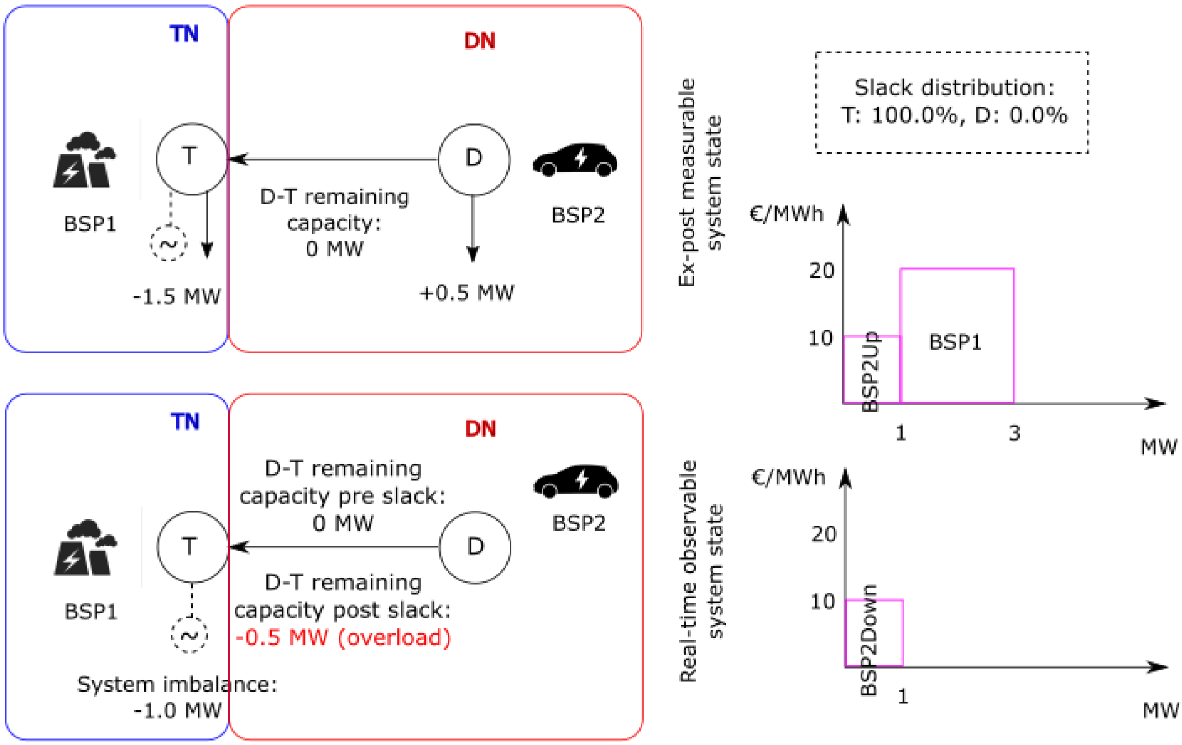

Figure 21: Recalling case 2.

The DSO asks BSP2 to increase consumption by 0.5 MW at a cost of 5 €. This amount is paid by BSP2 to the (distribution) grid because BSP2 receives energy. This will however cause an imbalance, and BSP2 will be charged for that at the imbalance price. Consequently, the total grid imbalance becomes -1.5 MW (BRPT = - 1.5 MW, BRPD = +0.5 MW, BSP2 = -0.5 MW).

The TSO hence needs to activate 1.5 MW upward, but cannot rely on BSP2 without congesting the DSO grid. Therefore, it activates BSP1 for 1.5 MW to resolve the imbalance.

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Table 16: An alternative approach to settlement for case 2.

Current approach	BSP1	BSP2	TSO	BRPT	BRPD	Grid
Activations	30€ (1,5 MW @20€/MW)	-5€ (0,5 MW @10€/MW)	-30€ (1,5 MW @20€/MW)			+5 € (0,5 MW @(20-10)€/MW)
Imbalances	adjusted	-10€ (0,5 MW @20€/MW)	30€ (1,5 MW @20€/MW)	-30€ (1,5 MW @20€/MW)	+10€ (0,5 MW @20€/MW)	0 €
Total	30€	-15€	0	-30€	+10€	+5 €

<u>Options to renumerate the BSP activated by the DSO/Discussion</u>

It is important to highlight that, because the portfolio of BSP2 is not adjusted based on its activation, BSP2 actually pays twice for its energy: once to the DSO when it is activated (at a cheap price because it is in a surplus area), and a second time to the TSO because it is imbalanced (hence at a bulk price which is not location specific). On the other hand, the DSO has resolved its congestion and has a net positive cash position for having done so. This seems to be inconsistent.

There are several ways to approach this phenomenon.

1. Let the BSP adjust its bid price to factor in the resulting imbalance

One way is to let the BSP internalize the fact that its portfolio will not be rebalanced according to its activation in case it is activated by a DSO. It implies that bid prices would be different and become in principle such that the BSP is always remunerated - whether for upward or downward bids (if in a surplus area, a decremental bid remunerates less than the bulk price, if in a deficit area, an incremental bid costs more than the bulk price[11]). The BSP bid prices in such a setup are dependent on the imbalance price – or actually on its forecast as imbalance prices are not known at the bid gate closure time (and in practice are rather hard to predict).

In the above example, BSP2 would probably price its decremental bid at -5 €/MWh (instead of +5

[11] A similar logic has been used in Enera (see section 2.2.1 above). Note however as a key difference with our context that the Enera time frame allows the BSP to rebalance on the intraday market and that the Enera bids are used solely for congestion management purposes.

€/MWh) if it is able to perfectly predict the imbalance price (which is a challenging task by nature). This means that it would receive 5 €/MWh to increase its load (i.e. it pays 5 €/MWh for the energy but receives 10 €/MWh to compensate for its imbalance).

There are several implications if such a bidding strategy is encouraged. For example, bid price monitoring becomes much more intricate (because of the "forecasted imbalance price" component and related risk premium - which are very difficult to audit). It also makes a cost-based settlement approach rather unrealistic (would this be contemplated). INC-DEC gaming is however not fundamentally different.

In the context of such an alternative approach, another challenge is that the same bids can be activated for different purposes, and their settlement principles become different depending on this purpose. More specifically, the portfolio of a BSP is compensated if the bid is activated for balancing purposes, but not compensated if the bid is activated for congestion management purposes / if it is activated by the DSO. Consequently, bids must have two different prices depending on their activation purpose. Such a setup has not been considered further (but is likely rather complex).

2. Let the DSO compensate for the energy

An alternative solution is to let the DSO activations be dealt with as "imbalance adjustments" to the BRP portfolio the same way bids activated by TSOs are handled. This means in practice that imbalances caused by activation are not punished and settled as imbalances. This appears to be the most attractive solution, as it treats all parties equally independent of the cause of activation. Further work is necessary to realize this solution in practice.

In Table 16 above, this solution implies that the BSP2 imbalance settlement would be moved to the last column so that the DSO (i.e. grid) settlement would sum up to -5 € (=+5-10) while BSP2 would pay -5€ in total. Hence the outcome is as expected: the BSP2 pays the value of its consumption while the DSO pays the congestion cost to resolve its grid issue (this is why BSP2 would bid at -5€ in the first proposal).

As the imbalance price is unknown at the time of activation, the imbalance price risk is thus transferred to the DSO. In the previous solution it was borne by the BSP, which however would include the risk in its bid price, and it would still be paid by the DSO. The DSO therefore takes a more explicit financial risk when activating BSP2 (it knows it will have an income of 5 €, but does not know how much will be on its expense). This may be problematic in case the DSO has alternative ways to cope with the congestion (for example accept to deviate from an N-1 standard, which implies a financial penalty from the regulator), which may ultimately be more cost efficient. In a system with this approach, standard ways to handle this would however certainly develop.

We discussed in Section 3.3.2 (see "grey box") of the report that it is possible to explicitly internalize the cost of such alternative "costly remedial actions" in the hierarchical TSO-DSO

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coordination approach, so as to ensure that the DSO does not pay more than what it is willing to pay.

6.3 Revisiting case 3

In the following figure we recall the conditions of case 3.

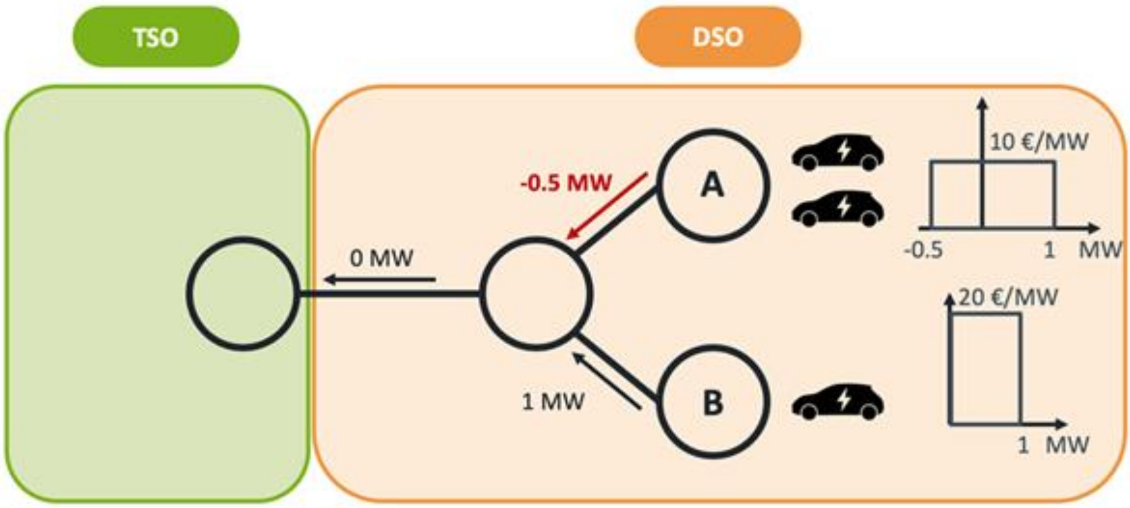

Figure 22: Recalling case 3.

The DSO asks BSPA to regulate downward by 0.5 MW. BSPA can thus source its additional load at the price of its accepted bid (10 €/MWh) for a cost of 5 €. This causes an imbalance cost for BSPA.

Subsequently, the TSO registers a need for 0.5 MW of upward regulation in order to handle the imbalance caused by BSPA. The TSO activates the best available bid (BSPB) for 10 € (0.5 MW at 20 €/MWh). BSPB therefore receives 10 €, and its portfolio is adjusted so that it does not incur any imbalance charges.

As 20 €/MW is the marginal balancing price, we assume that it becomes the imbalance price which is applied to the imbalance of BSPA.

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Table 17: An alternative approach to settlement for case 3 (assuming Approach 1 in Section 4.2.2).

Current	BSPA	BSPB	TSO	Grid
Activation	-5 € (0,5 MW@10€/MW)	10€ (0,5 MW@20€/MW)	-10€ (to BSPB)	+5 € (from BSPA)
Balancing	-10€ (0,5 MW@20€/MW)	adjusted	+10€ (from BSPA)	
Total	-15 €	+10 €	0	+5 €

Note that the same observations as in case 2 apply here (see the previous discussion of the an alternative approach for case 2).

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7. Summary

This report investigates how to exploit flexible assets at both the transmission and distribution levels close to real time for balancing and congestion management purposes.

Several pilot or commercial projects on similar objectives have been investigated (Enera, Gopacs, Nodes, Piclo, Cornwall, Soteria, Coordinet, Smartnet). These analyses have helped the project team to better shape the problem at stake. A key outcome of these analyses is that some of these projects often segment balancing and congestion management, rather than considering them as an integrated process. Nevertheless, the integration of balancing and congestion management is an attractive feature from an economic standpoint, and is well aligned with the Nordic balancing philosophy and present practice. For this reason, the present study has focused on solutions in the mFRR timeframe where mFRR-type bids from assets at transmission and distribution grids are activated for the two previously mentioned purposes.

Key desirable attributes of such a solution are:

(1) computational and IT scalability (i.e. relates to the challenge of combining and processing data from several system operators and potentially millions of grid users)
(2) possibility of gradual implementation where needed and relevant; no need for a "big bang" introduction
(3) consistency of pricing and dispatch instructions (i.e. implies settlement methods that provide efficient price signals while avoiding gaming opportunities), and
(4) institutional compatibility (i.e. in line with defined roles and responsibilities as well as European regulation / legislation)

A further technical challenge is the measurability at geographically granular level of imbalances (and congestions) in real time.

A “perfect TSO-DSO coordination”, which uses all available bids and grid data and computes locational prices has been defined as a benchmark. Such a solution outputs optimal economic results from a theoretical perspective (Attribute 3), however it is hardly realistic from a scalability perspective (Attribute 1), while it also neglects the actual and upcoming institutional arrangements (Attribute 4). Such an approach also must be implemented in one shot (Attribute 2)

This idealized method is then compared with a “hierarchical approach”. This approach is based on an “aggregation-disaggregation service” (ADS) for each DSO, which collects the grid constrains as well as the flexibility bids (mFRR-compatible bids complemented with locational information) of the distribution grid. The ADS then computes a so-called Residual Supply Function (RSF) which describes the least-cost way in which the given distribution subsystem can deliver – while respecting all the provided grid constraints – a certain aggregate upward or downward action at the point at which the distribution system is connected to the higher-level voltage network. This

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RSF is submitted to the TSO as an mFRR balancing market offer. By construction, the ADS ensures that (1) all overloads in the distribution grid are resolved and (2) its connected BSPs can participate to the mFRR balancing market as long as they do not further overload the distribution grid. The ADS then disaggregates the results and instructs the BSPs accordingly.

The hierarchical approach has been inspired by past work on a seemingly different context: one of enabling Statnett to participate in MARI while ensuring that its domestic network constraints are not violated [2]. In this predecessor study, Statnett rests at the lower level of the hierarchy, with MARI representing the higher level. In this present study, the lower level of the hierarchy corresponds to the distribution system, with the higher level corresponding to the transmission system. In both cases, the hierarchical approach aims at reproducing the outcomes of an efficient dispatch that respects the network constrains of the lower hierarchy, with a minimal exchange of information between the layers of the hierarchy, and in an institutionally compatible fashion.

The hierarchical approach set forth in the present report has several virtues. First, it is highly scalable (attribute 1): each DSO manages its own market and grid data, and shares with the TSO the relevant economic information in an aggregate and compact form. Secondly, such a data handling also allows a clear separation of the roles and responsibilities (Attribute 4): the ADS of each DSO manages its own congestions, and provides the TSO with the relevant information for balancing management. Third, it is versatile and allows multiple variants – different settlement/pricing schemes, price sensitivity for congestion management, …. (Attribute 3) – and enables a gradual implemented – can be implemented where/when a DSO needs it and is ready for it (Attributes 2)

Nevertheless, while in the simplified examples explored in this study the hierarchical approach reproduces the results of the "perfect DSO-TSO coordination" scheme, some technical limitations need to be further assessed for real-life cases. In particular, the existence of "block bids/indivisible bids" or of multiple TSO-DSO interfaces (i.e. non-radial networks)[12] may lead to suboptimal results. The approach also presumes that locational incentives/rewards at DSO level are acceptable for BSPs (and presumably also for BRPs).

In terms of settlement and pricing principles – and their impact on incentives and gaming opportunities – it has become clear that there exists a fundamental grid modelling inconsistency which can hardly be overcome by any approach. This is due to the zonal market design paradigm, which by definition does not allow for local price deviations within a price zone. As a consequence, no solution exists which provides localized prices for congestion management purpose without leading to any gaming risk. In other words, no "perfect pricing/settlement solution" exists, and only the "least bad solution" needs to be identified.

[12] The multi-period aspects may also be influential in principle – although they are not relevant for the integrated EU mFRR balancing platform MARI.

Based on the explored examples, we conclude that a marginal local balancing price (i.e. BSPs can have different prices depending on their location) would be the ideal solution, preferably if imbalance prices can also be set locally. As a practical alternative, maintaining a different settlement scheme depending on the activation purpose (i.e. paid-as-cleared for balancing and cost-based paid-as-bid for congestion management) as a way to reduce INC-DEC gaming (in line with the currently applied paid-as-cleared for balancing and paid-as-bid for "special regulation") deserves further investigations.

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