ASSET Study on

Smaller bidding zones in European power markets: liquidity considerations

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About the ASSET project

The ASSET Project (Advanced System Studies for Energy Transition) aims at providing studies in support to EU policy making, research and innovation in the field of energy. Studies are in general focussed on the large-scale integration of renewable energy sources in the EU electricity system and consider, in particular, aspects related to consumer choices, demand-response, energy efficiency, smart meters and grids, storage, RES technologies, etc. Furthermore, connections between the electricity grid and other networks (gas, heating and cooling) as well as synergies between these networks are assessed.

The ASSET studies not only summarize the state-of-the-art in these domains, but also comprise detailed qualitative and quantitative analyses on the basis of recognized techniques in view of offering insights from a technology, policy (regulation, market design) and business point of view.

Disclaimer

The study is carried out for the European Commission and expresses the opinion of the organisation having undertaken them. To this end, it does not reflect the views of the European Commission, TSOs, project promoters and other stakeholders involved. The European Commission does not guarantee the accuracy of the information given in the study, nor does it accept responsibility for any use made thereof.

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Executive summary

European wholesale electricity markets are based on a zonal approach for pricing electricity. Within each so-called bidding zone (BZ), congestion is assumed to be negligible and electricity is therefore priced uniformly (the network is considered as a copperplate). Prices between BZs differ when cross-zonal transmission capacity is scarce. Today, the geographical scope of a BZ often corresponds to a country, with a few exceptions. This is in contrast to the nodal pricing approach (e.g. several US markets), where the transmission grid constraints are fully internalized in the market clearing and electricity prices may therefore differ at each transmission node. When the BZ delineation is not consistent with the network congestions, the simplifications underlying the representation of the physical system in the zonal pricing approach may result in

1. inefficient price signals to consumers, producers and investors and

2. underutilized cross-border transmission capacity.

The discussion of zonal versus nodal pricing is not new. However, current zonal inefficiencies are expected to increase with the need to decarbonize the energy system. As a matter of fact, the transmission grid of the 20th century was designed to accommodate mainly centralized thermal generation. It is less and less adapted to integrate the intermittent generation patterns of wind and photovoltaics capacity spread across the country. Also, transmission grid expansion to accommodate more renewables takes time, is costly and often faces public opposition. The resulting higher levels of structural congestion trigger therefore the need to move to a more efficient, more detailed representation of the grid in the market. This may result in particular in smaller BZs.

Smaller BZs improve price signals for consumption (energy efficiency, flexibility), production (dispatch) and investment (where, how much and what). By offering more transmission capacity to the market, they also foster market integration and increase the exposure of energy companies to a wider competition, which eventually benefits the final customer.

However, smaller BZs also raise liquidity concerns when trading electricity. The goal of the study is to provide an updated view on whether reducing the size of bidding zones can have adverse consequences on liquidity and on market functioning and which remedies can be considered if needed.

The BZ reviews should seek configurations that ensure a more efficient congestion management and better price signals, which often result in smaller BZs. However, smaller BZs also raise legitimate concerns among some stakeholders. In particular, their tendency to both increase price volatility and fragment the market is often mentioned as drivers of lower liquidity levels. Illiquid markets complexify risk mitigation practices for participants, which eventually result in higher costs borne by final customers. In this regard, sufficient liquidity is essential to a well-functioning market. But when it comes to smaller BZs, our analysis suggests that the latter are not necessarily a fundamental driver of lower liquidity. In fact, the rationale is rather that the current design of some risk mitigation instruments cannot adapt well to new BZ configurations.

First and foremost, we deem it essential that physical (spot) markets must price the transmission externality in order to provide efficient incentives for production, consumption and investment decisions. In that sense, smaller BZs with inherent price volatility not only better reflect locational scarcity in the network but also signal the need for more flexibility. Volatility should thus be seen as a price signal that should be communicated to the market, rather than as a problem in itself. Thus, the search for the optimal BZ configuration should aim to make (spot) prices right first.

Getting the prices right first does not mean that liquidity considerations can be neglected. We emphasize that liquidity is complex to define or measure accurately, and the data used to support a direct (either positive or negative) correlation with smaller BZs may have been incomplete or anecdotal. Instead, the real issue lies not in the absolute liquidity levels, but in answering the need for market participants to hedge at a reasonable cost. Given the current state-of-play, further zonal splitting without prior measures may lead to situations where this is not the case for many Member States. Indeed, the hedging possibilities of market participants, at least in most continental Europe, depend largely on the bidding zone in which they are located. If a zonal forward market is liquid, it may be easy for participants to find a suitable local energy product. If not, and if zones prices are sufficiently correlated, they may rely on proxy hedging their energy (using a product of a more liquid BZ instead). However, market participants are also interested in hedging the residual transmission risk (the price difference between the local zone and the proxy), which may become significant with increased geographical granularity and price volatility. Transmission Rights are instruments that precisely exist to cover this risk. Their role should become more central under smaller BZs, since more transmission capacity is priced into the market.

TSOs are in charge of determining the volumes of Transmission Rights on each pair of adjacent zones across the EU, which they then sell on independent forward auctions. The only exception is the Nordics, which uses instead a purely market-based product know as Electricity Price Area Differentials (EPADs). At present Transmission Rights are either Physical (PTR) with a Use-It-Or-Sell-It condition (UIOSI), or Financial (FTR) Options. The economic value of these contracts can in theory be equivalent to holders. Yet, PTRs which entail physical delivery of energy and are nominated before market clearing, may result in worse outcomes even with UIOSI (e.g. in situation of scarcity). FTR Options have been progressively rolled out in Central-Western Europe but PTRs subsist in the Core region, and their replacement should be made a priority.

Another point of attention is the lack of coordination in the procurement of these rights, which may cause some costly mismatches between volumes sold and what the network can accommodate at delivery (leading to curtailment and compensation to holders). As long as auctions are disjoint for each border and based on a Net Transfer Capacity (NTC) approach, liquidity remains fragmented. Competition is also weak since 1) borders cannot compete with each other properly and 2) less capacity can be allocated due to the inaccuracies of the NTC approach (auction results do not necessarily represent a system-wide optimum). Thus, we would support the simultaneous auctioning of FTRs across continental Europe, based on a Flow-Based calculation of the available capacity. A single clearing across all borders would pool liquidity together and maximize allocative efficiency. This auction would be conducted periodically with updated forecasts, and complemented by secondary markets to allow participants to readjust their positions. Possibly, these improvements could lead to enough liquidity for multi-year maturities, which could then increase the potential for FTRs to be utilized for hedging.

Eventually, transitioning from the current implementation of cross-border (‘flowgate’) rights into a ‘Point-to-Point’ design could also benefit market participants by providing a more flexible hedging tool, especially when considering the roll-out of several price hubs. Hubs should be thought as large reference price regions to facilitate hedging when local liquidity becomes low, and should preferably be backed by the underlying physical capacity. More generally, we recommend to improve the design of transmission hedging products and to set a transparent methodology, to be integrated in the BZR, on how to transpose these zone-dependant contracts into new configurations.

Lastly, the increased potential for market power abuse is often brought forward by detractors of smaller BZs. In particular, a smaller BZ with lower liquidity would isolate incumbent players from competition and raise their market power as a result. The economic literature provides strong arguments to believe however that market power is a locational issue whose roots are independent of the zonal configuration. First, larger bidding zones with structural congestion require redispatch and some players, given their position in the grid, may exercise their market power in the redispatch mechanism. Second, looking at a single bidding zone may not be the most relevant market to define the boundaries of competition. Although smaller zones typically feature higher market concentration according to traditional metrics, cross-zonal competition is largely enhanced, as a better integration of grid constraints increases the overall transmission capacity provided to the market. Third, power prices internalizing grid constraints promote transparency and support market entry. If market power is nevertheless a concern, regulatory authorities have the capabilities to intensify their monitoring and detect possible abuses, as well as enough enforcement power to address the matter.

Summary of recommendations provided:

Recommendation	Legal framework and policy options
1) Pursuing and completing the phase-out of PTRs in favour of FTRs	FTRs are allowed by the FCA GL and already fully cover internal CWE borders. However, their utilization as a default LTTR is not a requirement yet. Setting an implementation roadmap or a review process in the FCA GL could speed up adoption
2) Centralized Flow-Based allocation of FTRs	JAO is already the central allocation platform. Gathering the FTRs under a central auction would be aligned with the CACM and FCA GL. The extension of the Flow-Based calculation from Day-Ahead to forward markets is allowed. However, the FCA GL should emphasize that FB allocation in LTTRs should be the default where FBMC is used in DAM. Art. 10 should make this more explicit. TSOs remain responsible for the capacity calculations.
3) Improve the ability for participants to readjust their positions more regularly, via longer LTTR maturities and secondary markets	Presently, LTTRs are offered on yearly and monthly timeframes, each via a single auction (usually performed M-1 to delivery). Since the FCA GL and HAR do not restrict the maturity offered for LTTRs, the volumes for the same delivery period could be readjusted across several auctions rounds at different maturities, e.g Y-1, Q-1 and M-1. It should be ensured that secondary markets can scale accordingly to provide continuous liquidity around the auctions and are aligned with future energy products.
4) Establishing a stable and transparent methodology to carry over ongoing contracts when reconfigurations occur.	FCA GL only states via Art. 27 that LTTRs on outdated BZ borders must be reimbursed to holders at purchase price. This should suffice as long as the lead time preceding a reconfiguration exceeds the complete lifetime of the contract (time to maturity + duration of delivery), e.g. 2-3 years. If/when this is no longer the case, hedging positions can be compromised and the FC GL should include the requirement to elaborate a grandfathering or re-auctioning methodology.

5) Replacing 'flowgate' FTRs by a Point-to-Point (specifically, Zone-to-Zone) design to enable transmission hedging between any two distant zones. Obligations over Options can facilitate the decomposition of such contracts into individual network element contributions.	The FCA GL currently imposes that LTTRs be allocated on each bidding zone border via Art. 28-31, which precludes the use of Zone-to-Zone transmission rights. Zone-to-Zone FTRs should therefore explicitly be introduced in the FCA GL. Having Flow-Based calculation already in place would facilitate the transition from a technical point of view, especially if complemented by Obligations FTRs. In this regard, the FCA GL already allows both Options or Obligations FTRs, although the wider economic implications in the EU context should be further studied.
6) Expanding Zone-to-Zone into Zone-to-Hub FTRs by constructing synthetic price hubs based on aggregated physical zones to create regional liquidity pools	The FCA GL does not make any provisions for synthetic hubs and Zone-to-Hub FTRs. Design requirements for synthetic zones would have to be established in the FCA GL (e.g. creation and validation process, rules for the determination of the contributions to price from underlying BZs, etc.). Within this organization, Obligations are again more economically sensible.

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List of abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
BZR	Bidding Zone Review
CACM	Capacity Allocation and Congestion Management
CRM	Capacity Remuneration Mechanism
DAM	Day Ahead Market
EC	European Commission
EFET	European Federation of Energy Traders
EPAD	Electricity Price Area Differentials
ENTSO-E	European Network of Transmission System Operators for Electricity
FB(MC)	Flow-Based (Market Coupling)
FCA-GL	Forward Capacity Allocation - Guideline
FTR	Financial Transmission Right
IDM	Intra-Day Market
JAO	Joint Allocation Office
LTA	Long Term Allocation
LTTR	Long-Term Transmission Right
MS	Member State
NEMO	Nominated Electricity Market Operator
NRA	National Regulatory Authority
PJM	Pennsylvania, Jersey, Maryland (US regional transmission organization)
PTR	Physical Transmission Right
PX	Power exchange
RAM	Remaining Available Margin
TSO	Transmission System Operator

Introduction

The European electricity target model is based upon a zonal pricing approach. As opposed to a nodal pricing system, where a price is defined at each node of the transmission system, the zonal model aggregates nodes into zones. This implies that intra-zonal congestion is not addressed by the market and remedial actions must be taken by the transmission system operators. Such actions can be non-costly (use of phase-shifting transformers and topological actions) but also costly (redispatching and countertrading)[1]. As part of the guideline on Capacity Allocation and Congestion Management (CACM, Commission Regulation (EU) 2015/1222), the bidding zones must be designed to foster an efficient and well-functioning market. A periodic assessment of the efficiency of BZs is therefore an integral part of the monitoring process performed by regulators, and may lead to a review of the zonal configuration. Smaller biding zones, in particular, often raise a question on possible market liquidity issues. This study investigates whether the design of smaller bidding zones could entail any adverse impact on market liquidity and what mitigation measures could be implemented to facilitate such fundamental changes.

The context is set first before the study objectives are further developed.

Context

The target model relies on a zonal approach, where each zone features a unique price per market time unit. Initially, in order not to create unmanageable disruptions when transitioning from national markets to this integrated approach, the Bidding Zone (BZ) configuration was largely overlapping with national borders. Yet, EU Regulation 2015/1222 (preamble 11) stipulates that BZs should be "*defined in a manner to ensure efficient congestion management and overall market efficiency*", thereby supporting an economic- rather than a political-based argument. A regular reporting on the current bidding zone configuration is therefore requested (Art.34). ACER may subsequently request TSOs to launch a review of the configuration and, in case a reconfiguration is proven more beneficial, the current zones can be "*modified by splitting, merging or adjusting the [...] borders*".

The first BZ review initiated in 2016 concluded in 2018 that there was no "*sufficient evidence for a modification of or for maintaining of the current BZ configuration*" (ENTSO-E, 2018). The market liquidity criterion was especially quite controversial:

- some stakeholders argued that the associated increased volatility and reduced pool size impedes the functioning of the market in terms of hedging possibilities, investment incentives and integration of renewables and market power could more easily be abused;
- other stakeholders argued that a likely drop of liquidity is outweighed by other positive effects (improved system operation, transparency on congestion, less out-of-market interventions, etc.) and cross-border hedging needs can be addressed by issuing long-term transmission rights;
- in general, because of its multi-dimensional nature, the effect of smaller bidding zones on liquidity is difficult to assess. Also, it is difficult to establish a clear link

[1] At EU level, a total redispatched volume of 51 GWh worth 2.14B€ was recorded by ACER in 2017 (ACER, Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Market in 2017, 2018a)

between a historical (e.g. Nordic market) or a future bidding zone split and liquidity without a detailed methodology.

This controversial view on liquidity in turn makes reaching a consensus on a new configuration very difficult at European scale (ACER, 2018b).

Objective of the study

In the context of an accelerating deployment of renewable capacity, the goal of the study is to provide an updated view on whether reducing the size of bidding zones can have adverse consequences on liquidity and on market functioning and which remedies can be considered if needed. In particular, the following aspects are covered:

- the economic implications of smaller BZs and the relevance of liquidity as a measure of success;
- the lessons that can be drawn from historical bidding zone splits;
- more suitable risk hedging mechanisms and market power mitigation measures to safeguard a well-functioning market with more price zones.

This work supports the European will to further enhance the integration of energy markets and maximise the use of existing infrastructures. Ultimately, the study should strengthen the European Commission's position not only in shaping its policies but also in obtaining the support of stakeholders and other bodies at play.

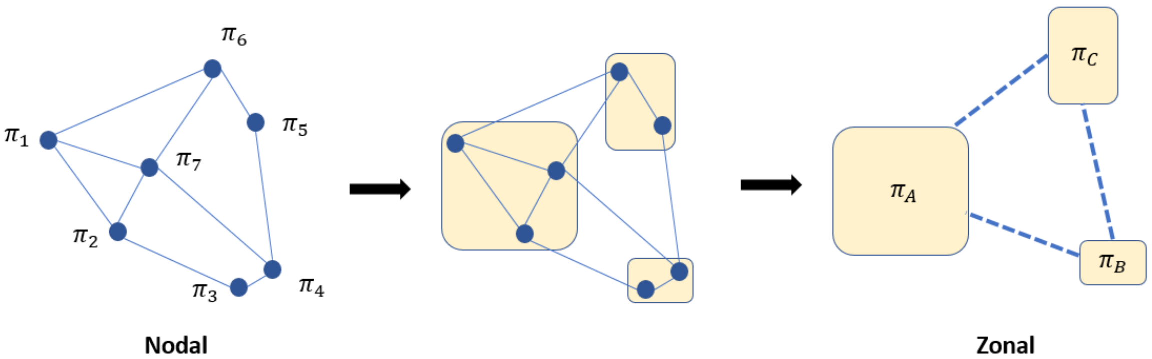
1. the EU Electricity market organisation – State of play

1.1. The European electricity target model

Electricity, unlike any other commodity, cannot be stored at large scales and therefore requires constant balancing between supply and demand through evolving network infrastructures. The cost of transmission must be reflected in the final energy prices in order to produce accurate economic signals. There exist various market principles dealing with transmission pricing, the most important being the zonal and nodal approaches. In a nodal setting (as applied in several US markets, but also in Argentina, Russia, etc.), the system operator acts as a regulated central planner and computes the supply-demand balance at every injection point – or "node" – in the transmission network. This disaggregated view allows the market to embed high levels of details in terms of the physics of the system into its clearing algorithm. As a result, a price for every single node can be computed for each market time unit and any scarcity in transmission capacity is immediately materialized in diverging energy prices between nodes. In most nodal systems, energy, transmission and reserve are co-optimized in spot markets which consist in a single day-ahead market followed by real-time auctions.

The European model, on the other hand, is based on a zonal pricing approach, whereby all nodes within a certain geographical region (a "zone") are aggregated into a single supply-demand pool with a single spot price. See Figure 1. The CACM Regulation stipulates that bidding zones should "*ensure efficient congestion management and overall market efficiency*" (Preamble 11). There is thus no imperative that a BZ must correspond to the geographically area of a country. In practice, some Member States (MSs) opted for several bidding zones (Sweden, Denmark, Italy), while Austria, Germany and Luxemburg first chose a common BZ before splitting it recently in two zones (Germany-Luxemburg separated from Austria). The island of Ireland (Ireland and Northern Ireland) is also organized in a single BZ. We will come back to historical experiences in Section 3.

The will of formerly national markets to retain some form of autonomy, coupled with the challenge to elect a single pan-European central system operator made zonal pricing a more popular choice. The zonal arrangement requires intra-zonal and cross-zonal congestion management. The responsibility is allocated between Transmission System Operators (TSOs) and power exchanges (PXs) as follows:
The role of the TSOs is largely restricted to ensuring the operational security in their respective control areas. TSOs are hence responsible for the activation of reserves but also for intra-zonal congestion management activities. PXs, also known as Nominated Electricity Market Operators (NEMOs) if they manage the market operation of the single day-ahead and single intraday coupling, treat the cross-zonal congestion. The CACM allows NEMOs to compete against each other - as they may be several covering the same zone - but market orders must be shared and collectively cleared so as to keep ensuring a single price per zone.



Source: Tractebel

Figure 1: From nodal to zonal grid representation

BZs are defined in Regulation 543/2013 of 14 June 2013 as "*the largest geographical area within which market participants are able to exchange energy without capacity allocation*". In other words, a BZ assumes infinite internal transmission capacity ("copper-plate" assumption), and only cross-zonal transmission capacity is considered in the day-ahead and intraday markets. This cross-zonal transmission capacity is typically jointly allocated with the electricity on the market (implicit allocation of transmission rights).[2] The quantity defined by the resulting price spread between two BZs multiplied by the transiting flow of energy is called the congestion rent. The revenues generated in this fashion are collected by TSOs and should, according to Regulation No 714/2009, be used to fund infrastructure investment or congestion management.

The implicit transmission capacity allocation in spot markets is performed either under the Available Transfer Capacity (ATC) or the Flow-Based (FB) methods. In the former, exchanges are said "commercial" since flows between two zones are simply capped by a maximum transfer capacity which is an ex-ante approximation conducted by TSOs. The term "commercial" stems from the simplicity of the method which disregards the physics of electricity. Indeed, according to Kirchhoff's laws, electricity always follows the path of least resistance and as such a point-to-point transfer cannot be fully channelled in a single line but rather results in multiple parallel flows. On the other hand, the FB

[2] Note that the CACM Regulation specifies that "*capacity should be allocated in the day-ahead and intraday market time-frames using implicit allocation methods, in particular methods which allocate electricity and capacity together. In the case of single day-ahead coupling, this method should be implicit auction and in the case of single intraday coupling it should be continuous implicit allocation*."

method used in Central-Western Europe (CWE) includes simplified Kirchhoff constraints, thereby acknowledging that exchanges between BZs cause have an impact on other relevant network elements. As a result, more transmission capacity can be offered to the market. This more complex representation better describes the physical system, although the aggregation at zonal level still implies a loss of information on some local infeasibilities which must then be corrected. The congestion which remains after the implicit transmission capacity allocation in the market is therefore treated mostly in a curative rather than preventive manner. Because the network is not fully represented ahead of delivery, TSOs must mitigate this congestion using close-to-real-time redispatch, counter-trading or non-costly measures (topology changes or Phase Shifting Transformers positioning).

Finally, the fundamental volatility in spot prices (where spot markets are understood as physical markets close to delivery, i.e. day-ahead or closer) brings traders to hedge their positions ahead of delivery, often via forward markets. In this case, both energy and transmission are allocated explicitly. Such markets typically do not exhibit as much coupling between regions. Forward energy is sold by regional PXs while transmission capacity is explicitly auctioned by TSOs in the form of Long-Term Transmission Rights (LTTRs) via the Single Allocation Platform (SAP) which is governed by the Joint Allocation Office (JAO). Following the Network Code on Forward Capacity Allocation (FCA), these products should cover various maturities (currently yearly and monthly) and be traded back into secondary markets. LTTRs are taken into account by TSOs when computing final transfer capacities for the Day-Ahead market to make sure the underlying capacity is still available (firmness problem).

1.2. Shortcomings of the current BZ configuration

Adequate BZs arise as a "*cornerstone of market-based electricity trading*" and "*a prerequisite for reaching the full potential of capacity allocation method*" (CACM Preamble 11). As mentioned earlier, the BZ delimitations have been generally based on national borders and, as a result, several sources of inefficiencies have persisted or gradually appeared, including the following:

- **Inefficient price signals:** Often, the assumption that transfer capacity is never restrictive within current BZs does not hold. Bottlenecks in intra-zonal transmission (e.g. resulting from increasing demand or RES penetration) alter and therefore distort the dispatch of generation. The costs of remedial actions must be socialised across end consumers in the form of grid charges. In 2018, for instance, the remedial actions totalled almost 1.44bn Euro in Germany alone (BundesNetzAgentur, 2019b). This creates a second distortion, at the level of consumption choices, as consumers are not exposed to the true cost of electricity. This prevents in particular demand side flexibility and storage options to be developed. Thirdly, investment decisions can be misguided. This is supported by anecdotical evidence where MSs have introduced specific reserve schemes to maintain existing or to attract new capacity to address national adequacy concerns. Moreover, congestion management costs have become a source of tension because they pose a cost allocation problem among TSOs. This is partially due to sharing the cost of unplanned loop flows, which arise when a commercial exchange within a zone (which the DA market cannot 'see') creates parallel flows in neighbouring areas. These flows can thus endanger operational security since the physical line capacity in real-time is lower than what the DA market uses to compute the dispatch (THEMA CG, 2013).

- **Under-utilized cross-border transmission capacity:** TSOs must discount various components including safety margins and (incomplete) expectation of internal and loop flows from the full transmission capacity in order to ensure operational safety. These methodologies are not always harmonized and past abuses led some TSOs to further limit import and export capacities. These were attempts to shift congestion back to their borders, i.e. having the market pay for it rather than assuming the full cost of redispatch themselves. The Electricity Regulation framework now stipulates that TSOs "shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone or as a means of managing flows resulting from transactions internal to bidding zones." Furthermore, Article 16 requires at least 70% of the total capacity to be made available across all MSs by 2026. Indeed, underutilized cross-zonal capacity creates inadequate price signals, lowers cross-border competition and increases overall costs for the final customer.

These issues undermine the target model's ability to deliver some of its objectives set in the CACM. Most notably one can expect that the shortcomings will occur more often in a power system characterized by increasing renewables. The transmission grid of the 20th century was designed to accommodate mainly centralized thermal generation. It is less and less adapted to integrate the intermittent generation patterns of wind and photovoltaics capacity spread across the country. Moreover, transmission grid expansion takes time, is costly and often faces public opposition. As a result, a better alignment between the market view and the physical constraints of the grid is often suggested. Given the abundance and dispersion of congestion, smaller bidding zones would be favoured. A general consensus is that the latter improve the information contained in electricity prices. Because more of the network infrastructure is represented, they provide better ground to co-optimise energy and transmission. In theory, they should provide better consumption, production and investment signals and help addressing bottlenecks much earlier in the market sequence.

1.3. Bidding zone review in the European legal framework

Articles 32 to 34 of CACM deal with the process to review bidding zone configurations. ACER assesses the efficiency of the current bidding zone configuration every three years. To this end, it requests ENTSO-E to draft a technical report, evaluating the impact of the current bidding zone configuration on market efficiency. In particular, the analysis should include a view on structural congestion and how this is expected to evolve with investment in networks or significant changes in generation or in consumption patterns. The analysis shall cover the last three calendar years preceding ACER's request and a forward-looking scenario encompassing ten years. As a result of this report, ACER may request TSOs to launch a review of the existing bidding zone configuration (Art.34). Not only ACER can launch a review, but several National Regulatory Authorities (NRAs) can also initiate a bidding zone review following the ENTSO-E's report. Furthermore, MSs in a capacity calculation region, TSOs in a capacity calculation region together with all concerned TSOs or single NRAs or TSOs (in case the impact on neighbouring control areas is negligible) are empowered to launch a review (Art. 32). Art.33 lists a minimum set of criteria that should be considered in a bidding zone configuration review. These criteria are studied in more detail in the next section 2. The Electricity Regulation 943/2019 introduces some changes in the requirements and the governance of the bidding zone review process. In particular, ACER is required to make a decision on the bidding zone review methodology and the alternative bidding zone configurations to be studied, when NRAs are unable to agree on those two aspects. However, the final decision on whether to change or maintain bidding zones lays on MSs.

2. Liquidity aspects of smaller bidding zones

As hinted in the previous section, the implementation of smaller bidding zones is hampered by a number of fundamental challenges which are presented by TSOs in the first edition of the BZ Review (BZR), initiated by ACER in December 2016 and lasting till March 2018. Figure 2 provides a synthetic view on the 20 BZR evaluation criteria as defined in Art.33 of CACM. In the BZR, these criteria are classified into three main categories: network security, market efficiency and stability & robustness of bidding zones. The question of market efficiency is central and encompasses more than half of the criteria.

Network security	Market efficiency	Stability and robustness of bidding zones
– Operational security (5.4) – Security of supply (5.5) – Degree of uncertainty in cross-zonal capacity calculation (5.6)	– Economic efficiency (5.7) – Firmness costs (5.8) – Market liquidity (5.9) – Market concentration and market power (5.10) – Effective competition (5.11) – Price signals for building infrastructure (5.12) – Accuracy and robustness of price signals (5.13) – Long-term hedging (5.14) – Transition and transaction costs (5.15) – Infrastructure costs (5.16) – Market outcomes in comparison to corrective measures (5.17) – Adverse effects of internal transactions on other bidding zones (5.18) – Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes (5.19)	– Stability and robustness of bidding zones (5.20) – Consistency across capacity calculation time frames (5.21) – Assignment of generation and load units to bidding zones (5.22) – Location and frequency of congestion (market and grid) (5.23)

Source: (ENTSO-E, 2018)

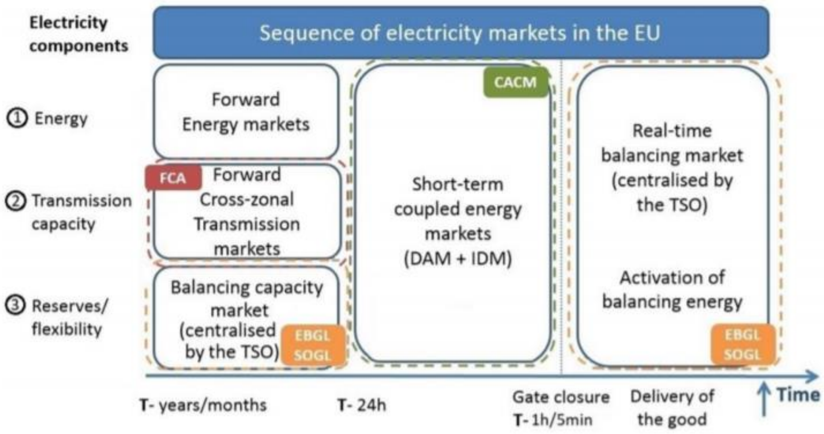
Figure 2: Evaluation criteria as classified by ENTSO-E in the BZR

The reader is invited to refer to (ENTSO-E, 2018) for a more in-depth assessment of network security and BZ robustness aspects, as the central focus of this report remains the market liquidity criterion. Yet, the latter appears intertwined with many of the other criteria grouped under market efficiency. Thus, this section chooses instead to discuss the main counter-argument to smaller BZs:

Smaller bidding zones introduce more price volatility and tend to complexify risk mitigation practices, thereby reducing overall market liquidity. This in turn will lower long term investment incentives.

2.1. Volatile prices increase risk exposure for market participants

As explained in the previous section, smaller BZs are strong drivers for a more efficient use of the network in the short-term: with spot markets considering more network elements, market-based dispatches are better aligned with the physical reality. However, because transfer capacity is more restricted, decoupling between zones (hence prices) is more likely to occur. This is the reason why smaller BZs are often said to increase price "volatility", which is commonly understood as the fluctuations in the price of a commodity (although in theory, price volatility specifically defines the level of variations rather than the variations of levels). Such corrections in the functioning and outcomes of the short term energy markets (DAM, IDM) affect the entire market sequence of the European target model (Figure 3), since bidding zones have to be identical for all market timeframes.



Source: (Florence School of Regulation, 2019)

Figure 3: EU Electricity market sequence

Increased fluctuations in short-term market prices mean that the outcome for participants is more uncertain. The risk exposure for participants increases by making their realized cash flow more volatile. Because the magnitude of these variations can be quite considerable[3], energy companies typically behave as risk-averse agents and will seek ways to secure more stable cashflows in order to reduce their final risk exposure to adverse price movements. This indicates that companies are likely to change the strategy by which they manage their energy volumes along the market sequence, with possibly a higher reliance on forward markets where they can lock in fixed prices over longer timeframes (weeks, months, years)

Forward markets are financial marketplaces providing instruments to reduce (or 'hedge') exposure to unfavourable outcomes later in time. Ensuring that this hedging can be performed in an optimal way is of high importance. In this respect, smaller BZs may complexify the forecasting of the underlying spot price at delivery, and by extension the upstream risk management activities. It is precisely the impact on forward markets – which already concentrate most trades[4] – that stakeholders are concerned with.

2.2. Liquidity: what metrics, what concerns ?

A forward environment where market participants are able to efficiently manage their risk ahead of delivery, is an important feature of a well-functioning energy market. Intuitively, one could think of several factors that would facilitate this process, but in fact these all refer to a single central notion, that of *liquidity*:

What is liquidity ?

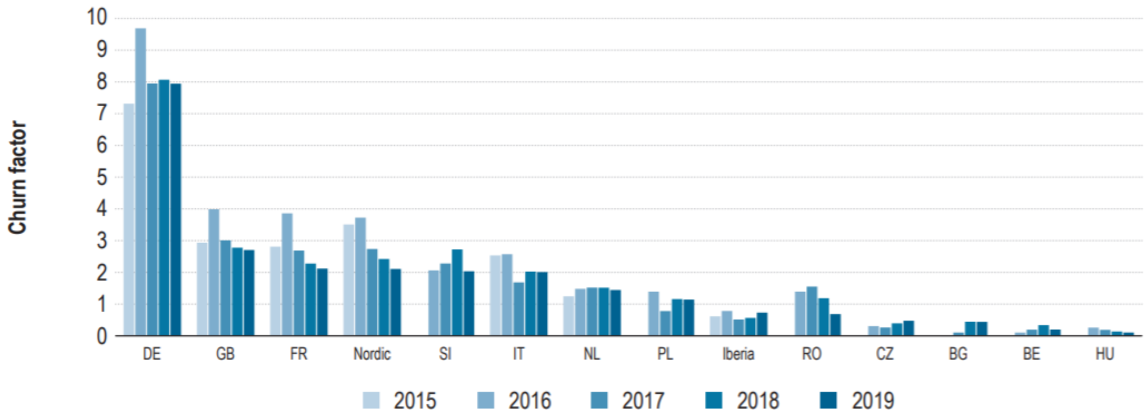
Market liquidity may refer to the speed and easiness by which assets can be bought or sold without drastically impacting the underlying market price. Concretely, for energy traders, this translates into several requirements such as having volumetric markets with many counterparties, sufficient product variety, adequate price discovery, low transaction fees and execution complexity.

[3] For instance, DAM prices are restricted between -500 and +3000 €/MWh in the EU.
[4] See (ACER, 2020)

Liquidity is a multidimensional concept whose definition remains quite high-level. In order to assess more precisely how 'liquid' a market is, many quantitative metrics have been developed, although none of them is able to fully encompass all relevant aspects at once. A non-exhaustive list includes:

- **Turnover**: The total traded volume or value generated over a specific timeframe, reflects global trend in market activity;
- **Open interests**: The total number of pending (not yet settled) trades on a forward exchange or for a specific product. Numerous unclosed positions indicate a high willingness to participate;
- **Churn rates**: The total traded volume divided by its targeted physical demand. Although there is no agreement, many stakeholders believe a churn of at least 300% is required for a market to be considered liquid (Economic Consulting Associates, 2015);
- **Market depth:** The ability of the market to absorb orders without them drastically affecting prices (measured graphically or using Kyle's Lambda in practice (Lillo, 2016));
- **Bid-ask spread**: The difference between the lowest buying price and the highest selling price (both in-the-money). It is a direct measure of transaction costs for a specific instrument and should remain low (EFET, 2016));
- **Time to maturity**: in a forward market, defines the time between the execution of the forward trade and the target delivery period.. Longer maturities (3+ years) indicate liquid products and better price discovery;
- **Risk premiums**: The difference between the forward price and the spot price of the underlying period (DNV-GL, 2020). A positive risk premium may indicate a scarce market or a high risk-aversion from buyers. Meanwhile, negative premiums (discounts) can point to a high risk-aversion from producers or an oversupplied market.

Traders in particular have expressed many concerns about EU forward liquidity using such metrics through position papers (EFET, 2017) or answers to surveys (EFET, 2016) They argue that forward markets should be given more consideration in the BZR process, given their size and their already low liquidity levels. For instance, only Germany has managed to retain a churn rate higher than 3. See Figure 4.



Source: ACER (2020)

Figure 4: Churn rates across main EU forward markets

Further, in the BZR of 2018, stakeholders shared their view on the proposed splits and agreed they would result in lower liquidity across all market timeframes (excluding balancing) with respect to the current configuration. See Figure 5, where (‘strong’) ‘decrease’ represents an estimated reduction of the traded volume by 10-25% (more than 25%) and/or an increase of the bid-ask spreads by 10-50 % (more than 50%).

Type of market	Answer type	Impact by DE/AT-Split	Impact by Big Country Split	Impact by Big Country Split 2
Intraday trading	Change of liquidity	decrease	strong decrease	strong decrease
Day-ahead trading	Change of liquidity	decrease	strong decrease	strong decrease
Forward/future markets – shorter period	Change of liquidity	decrease	strong decrease	strong decrease
Forward/future markets – longer period	Change of liquidity	decrease	strong decrease	strong decrease

Table 5.9: Summary of stakeholders' answers to the second survey on market liquidity

Source: (ENTSO-E, 2018)

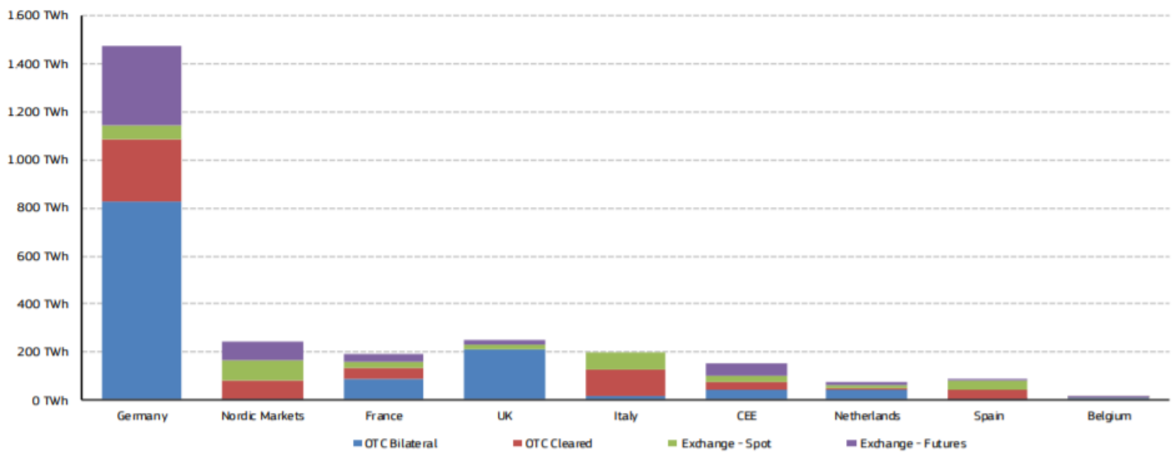
Figure 5: Liquidity impact of BZ changes

The notion of self-reinforcing liquidity was also evoked: “liquidity attracts liquidity”. A liquid marketplace incentivizes more participants to join, thereby creating a positive recursive loop. This loop takes time to build up, and so do the trust and understanding investors have of the market environment. In their view, an ever-changing configuration could deter the more risk-averse investors and cause some major setbacks for those markets that are already poorly liquid. However, the extent to which these effects would materialize in practice have not been explicated with clear quantified evidences.

2.3. The fragmentation of current risk hedging products

In order to better understand how energy companies manage their risk and how liquidity may impact the latter activities, this section delves into the current organization of forward markets and its evolution under smaller BZs.

Forward markets are the predominant risk management tool for market participants against real-time uncertainty. They have the dual purpose of ensuring adequate hedging and price discovery. Contracts are either standardised exchange products or Over-The-Counter (OTC), where the agreement is self-regulated and facilitated by a broker. The vast majority of trades happen OTC (Economic Consulting Associates, 2015) or even off-exchange, and their evolution under smaller BZs are difficult to measure. Because the details of these operations are usually not disclosed, many analyses tend to omit these volumes.



Source: (DG Energy, 2019)

Figure 6: Traded volumes by type and market, Q2 2019

Typically, contracts can cover a wide range of maturities (from a few days to years) and time coverage (baseload, peak), but only few products remain sufficiently liquid in the EU to be used in practice. The **energy price risk** (“basis risk”) is therefore mostly hedged using classical electricity futures, Contract-for-Differences (CfDs) and options (Economic Consulting Associates, 2015). In the case where energy hedges are not available or not liquid in a specific zone, contracts from other zones can also be used as a proxy when the price correlation between the two zones is high enough (DNV-GL, 2020). For example, central European countries have relied extensively on the liquid German market as a proxy-hedge to cover their risk.

Meanwhile, **transmission risk** hedging has historically shown to be more marginal, as can be observed by the consistent under-fulfilment and negative premiums of associated auctions (ACER, 2015). However, if cross-zonal prices were to decorrelate to a larger extend, proxy hedging alone would not be sufficient. Participants in illiquid zones would have stronger incentives to contract energy futures on a liquid hub, and complement it with a Long-Term Transmission Right (LTTR) towards their own zone to cover the price spread. In order for participants to hedge efficiently, reliable transmission risk products must therefore be made available (FCA GL, Article 30).

There are currently three main types of LTTRs in use in the EU:

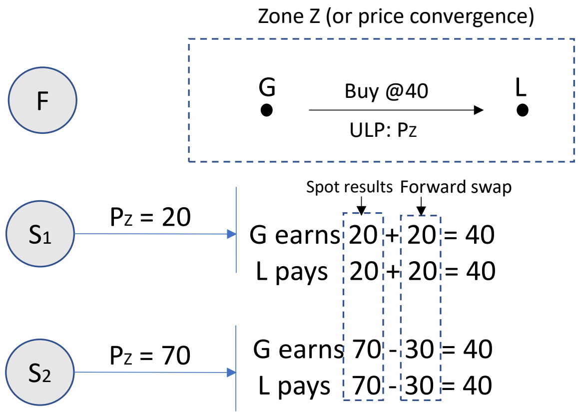
- **Physical Transmission Rights** (PTRs) entitle the holder to a physical transfer of a pre-agreed quantity of energy through a set interconnector and direction. EU PTRs are designed around a Use-It-Or-Sell-It (UIOSI) principle, by which any non-nominated PTR capacity is automatically reallocated into the DAM against financial compensation for the holder. This avoids capacity withholding issues in real-time.
- **Financial Transmission Rights** (FTRs) provide the holder with the option (or obligation) to settle a cash flow equal to the price difference between two adjacent zones multiplied by a pre-agreed quantity of electricity through a specific interconnector and direction. If the price difference is positive, the holder receives the congestion rent. If the price difference is negative (wrong FTR direction with respect to congestion), the holder of a FTR-Obligation must instead pay the congestion rent. Meanwhile, a FTR-Option holder can in that case choose not to exercise the option (no negative cash flows). Both are legally allowed, but only Options are currently used in the EU.

Electricity Price Area Differentials (EPAD) are market-based products available only in the Nordics and traded on NASDAQ. Although not technically transmission rights per se, EPADs allow participants to hedge the difference between the zonal price and a “system price” which is calculated as the price of the Nordic region under a copper-plate assumption (infinite transmission in the whole area). Contrary to both PTRs and FTRs, EPADS are not backed by physical capacity, and thus cannot be subject to curtailment. Finally, EPADs are sold as Obligations which ensure that the system price is perfectly hedged (on the upside as well as on the downside).

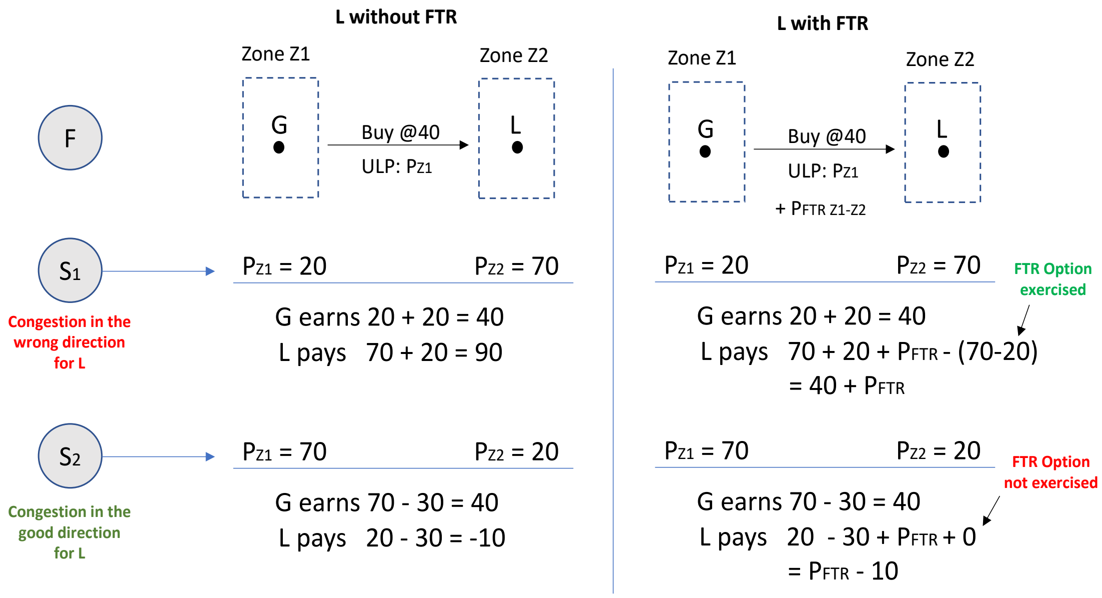
A simplified load hedging strategy using LTTRs

A load L contracts a 1MWh CfD with a generator G in a Forward market F at a forward price of 40. The UnderLying Price (ULP) of the contract is the spot price P in G's area. The payout differs depending on the Spot results S and on the additional use of FTR. All values are indicative and in €/MWh.

- The two parties are in the same zones or in two zones with equal (spot) price:



- The two parties are in different zones and prices are decoupled:



LTTRs allow the holder (L) to reduce the volatility of the payout (-10 to 40, rather than -10 to 90) and recoup losses when the congestion is in the wrong direction.

PTRs have traditionally been the dominant form of LTTR in the EU. Originally, interconnectors between national markets were primarily built for security and back-up reasons. Cross-zonal exchanges were a lot more marginal, and loop flows could be ignored for the most part. "Contract-path" types of LTTRs, such as PTRs, were therefore introduced via grandfathering of pre-liberalization arrangements, and began to be auctioned on each specific cross-zonal interconnector (yearly and monthly timeframes).

Today, the EU has completed the centralization of all procurements on JAO under the Harmonized Allocation Rules (HAR). Individual TSOs remain responsible for defining the type and volume of products they offer on each specific interconnection, for which they own the cross-border capacity. The sale of LTTRs is directly received by TSOs[5], which must also bear the costs of guaranteeing the firmness of the underlying capacity (i.e. ensuring this capacity is available in real-time when exercising the contract, or else compensating holders).

When splitting BZs, additional dedicated energy and transmission hedging contracts have to be introduced: if the number of zonal borders doubles, so does the amount of LTTRs to be offered. This scatters participants across a range of less liquid products. Most often only total market volumes are compared when assessing liquidity. However, were that same total volume fragmented across more products, worse liquidity features would ensue. Because more zones and transmission elements have to be hedged against, product-specific open interests become more difficult to settle (fewer matching counterparties and/or higher costs). Further, the additional number of interconnectors on which LTTRs can be traded also tends to increase the firmness costs incurred by TSOs.

Finally, a BZ reconfiguration will inevitably result in winners and losers. From a risk perspective, new BZs affect the relative risk exposure and need for hedging between participants in different locations. Some participants may have to pay higher prices due to consistent transmission scarcity in the new region, while others may find a better proxy hedge reducing their costs. Mechanisms to at least guaranteeing a smooth transition from pre-existing arrangements may be a necessary condition to reach consensus.

2.4. Conclusion

Smaller BZs affect the entire market structure. They promote more efficient congestion management, short-term price formation and competition, thereby lowering the overall electricity supply cost for final consumers. Yet there are also valid concerns that the deterioration in the stability of short-term prices and in the ability to hedge the underlying risk can pose major problems for market players. To illustrate, the TSOs' conclusions of the 2018 BZR, after consulting with experts, are summarized in Figure 7 ('(+)' reflects improvements from the current configuration, '(-)' deteriorations and '(0)' an absence of effect or of evidence thereof).

The findings by ENTSO-E suggest that smaller bidding zones tend to decrease liquidity and hedging opportunities while increasing market concentration and price volatility. On the upside, they promote efficient congestion management and price formation. According to the BZR, better spot prices are only a weak driver for long-term investments, for which the timeframe often spans over a decade and where political, regulatory, transmission and generation uncertainty are the main decision factors. Last but not least, some transition costs must also be anticipated. These mostly depend on how much preparation time is given ahead of splitting, with generally 3 years recommended to re-adapt trainings, infrastructures, IT, etc. and transfer existing contractual obligations (via grandfathering or auctioning). Overall, the BZR reached mixed results which did not allow ACER and ENTSO-E to provide robust recommendations and settle the case.

[5] According to the economic theory, the sale value of an LTTR should be precisely the cost of the congestion it hedges at delivery. Therefore, in principle, the sale of all LTTRs can and should be solely funded by the congestion rent earned by the TSOs.

Bidding Zone Configuration (evaluation compared to current bidding zone configuration)	**DE/AT Split**	**Big Country Split**	**Big Country Split 2**	**Small Country Merges**
Network security				
Operational security	(+)	(+)	(+)	(-)
Security of Supply (for the entire system, short-term)	(0)	(0)	(0)	(0)
Degree of uncertainty in cross-zonal capacity calculation	(0)	(0)	(0)	(0)
Market efficiency				
Economic efficiency	(0)	(0)	(0)	(0)
Firmness costs	(-)	(-)	(-)	(+)
Market liquidity	(-)	(-)	(-)	(+)
Market concentration and market power	(-)	(-)	(-)	(+)
Effective competition	(0)	(0)	(0)	(0)
Price signals for building infrastructure	(0/+)[a]	(0/+)[a]	(0/+)[a]	(0/-)[a]
Accuracy and robustness of price signals	(0)	(0)	(0)	(0)
Long-term hedging	(-)[b]	(-)[b]	(-)[b]	(+)[b]
Transition and transaction costs	(-)	(-)	(-)	(-)
Infrastructure costs	Reference to investment costs as published in the TYNDP 2016			
Market outcome in comparison to corrective measures	(+)[c]	(+)[c]	(+)[c]	(-)[c]
Adverse effects of internal transactions on other bidding zones	(+)[d]	(+)[d]	(+)[d]	(-)[d]
Impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes	(0/-)	(-)	(-)	(0/-)
Stability and robustness of bidding zones				
Stability and robustness of bidding zones over time	(0)	(-)[e]	(-)[e]	(0)
Consistency across capacity calculation time frames	(0)	(0)	(0)	(0)
Assignment of generation and load units to bidding zones	(0)	(-)	(-)	(0)
Location and frequency of congestion (market and grid)	(+)	(+)	(+)	(-)

Source: (ENTSO-E, 2018)

Figure 7: Liquidity impact of BZ changes

A short critique of the issues raised in the BZR:

- Liquidity and price efficiency are compared as equally beneficial, whereas the European regulation clearly refers to "economic efficiency" as something to be maximised in the BZR context (e.g. article 14.1) while it refers to "liquidity" as something to be ensured (rather than maximised, preamble 19). From our analysis, it seems that price efficiency has a more direct contribution to the objectives set by the CACM including more optimal use of infrastructure, higher operational security, and improvement in the calculation and access of cross-zonal capacity (see section 1.2). Short-term efficiency can and should be achieved, as long as markets remain *sufficiently* liquid. Also, while it is rather clear that the liquidity of current forward arrangements would deteriorate, the BZR looks at the status quo and does not consider possible improvements to these mechanisms. Liquidity should be high enough to ensure participants have tools to reduce their risk exposure when necessary. Yet, prioritizing more volumetric markets would eventually lead to re-enlarging BZs and to shift the unchanged physical risk of delivery out of market where less efficient mechanisms result in additional costs borne by end consumers.

- Moreover, the BZR clearly lacked depth in some aspects of its analysis of smaller BZs. For instance, it did not investigate much the benefits of improved competition due to opening up borders, or of the new market opportunities created by the increased price volatility (demand side flexibility, flexible assets, storage, etc.). In addition, its views on liquidity mostly stemmed from stakeholder engagement rather than from econometric studies.

In the next sections, we show how these rather static conclusions may not paint a complete picture. We first draw empirical lessons from the historical EU split cases and their experience. We then point to several measures in line with the FCA GL and the CACM which would mitigate some of the potential downsides of moving to smaller BZs.

3. Review of historical zone splits in the EU

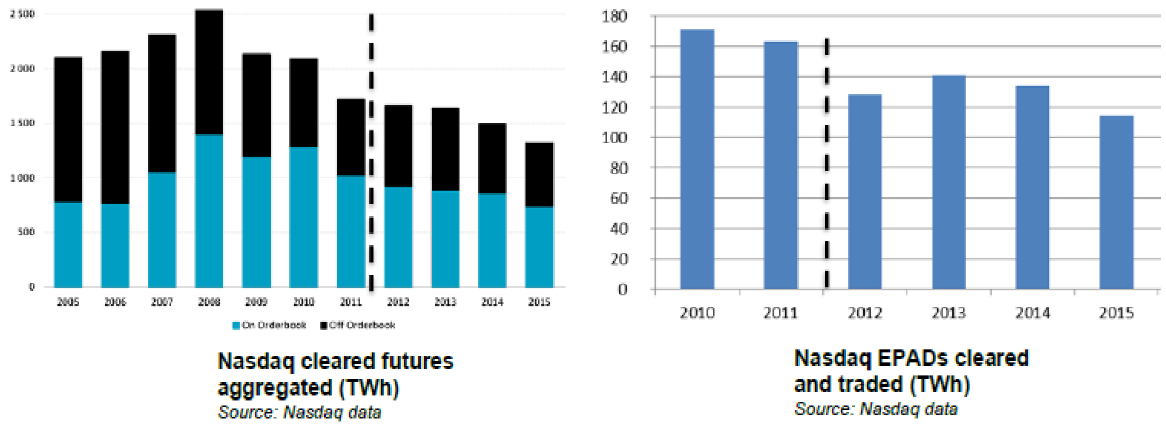
The recurring issue with simulations and models when analysing smaller BZs is that they are often simplified representations of a much more complex reality. Especially the change of liquidity is hard to model based on fundamentals. It is therefore valuable to complement the technical analysis by investigating the outcome of actual bidding zone splits. Historically, such events have also happened across the world with famous cases such as the US, New-Zealand or Australia going for different degrees of nodal approaches. However, the regulatory background playing an important role in the analysis, we focus here on three concrete European cases, namely the Nordics, Italy and the more recent DE-AT-LU split.

3.1. The Nordics

The Nordic electricity market is composed today of Norway (NO), Sweden (DE), Finland (FI), Denmark (DK), and the Baltic countries. For more than a decade, price zones were delineated at national level due to good regional interconnectivity. This last feature also contributed to the relevance of using a congestion-free system price (SYS) as the main reference to hedge the basis risk. However, as zonal prices gradually decorrelated from the system price, the EPADs had to be introduced in order to reduce exposure to these spreads.

In early 2010, a case was taken to court against the Swedish TSO Svenska Kraftnät (SvK) who 'may have curtailed export capacity on the Swedish interconnectors when it anticipated internal congestion within the Swedish transmission system, thereby discriminating between different network users and segmenting the internal market' (European Commission, 2010). The ownership-unbundled TSO was found guilty of pursuing non-economic goals by offering only 42 percent of its ATC on average so as to keep redispatch and national prices low, thereby going against the principles of the European Target Model. This led to the Swedish TSOs making a commitment in 2011 to split into 4 new price areas, thereby increasing the total number of zones in the Nordic Market to 15 (4SE, 5NO, 2DK, 1FI, 1EE, 1LV, 1LT). At that point, Norway had already been progressively split due capacity shortages caused by a series of cold winters and low hydro years.

In the following years, traders vividly commented on the negative impacts this event had on forward liquidity, with for instance a 20 percent reduction in traded futures and a "cumulative drop of close to 30 percent" in traded EPADs across the entire region. See Figure 8.

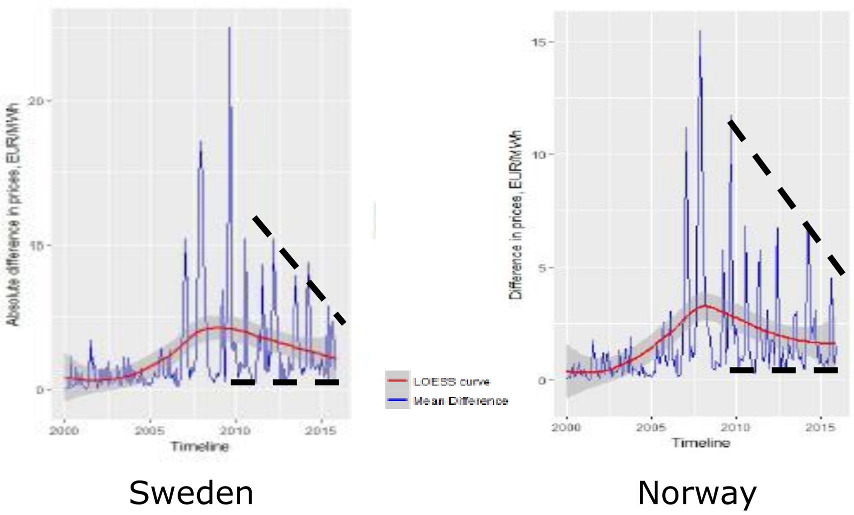


Source: (EFET, 2016)

Figure 8 : Liquidity impact of Swedish split as presented by EFET

However, these figures and charts must be weighed against the following arguments:

- They only cover NASDAQ volumes and hence disregard both the trades settled off-exchange and the growing presence of EEX as a competing PX to trade Nordic Futures.
- The Nordic market remains the fourth most liquid in the EU in terms of churn and third in terms of bid-ask spread (ACER, 2020). Both the Nordic NEMO (Nordpool) and the Swedish Regulator (Ei) agree that the split had a positive impact on the market overall.
- (Spodniak, Collan, & Makkonen, 2017) showed that the forward risk premiums were on average negative, which indicates that many contracts were sold at a discount. This sell-side pressure could point to a lower demand for EPADs and need for consumers to hedge ahead of delivery. This would correlate with (Gerasimova, 2017) who found a decreasing spread (increasing correlation) between the system price (SYS) and zonal price for SE and NO following the split. See Figure 9.



Source: (Gerasimova, 2017)

Figure 9 : Increase in Zone-SYS price convergence post-split

According to Ei, the low liquidity levels of some EPAD contracts (eg NO5) is not a fundamental issue as it stems from a high zone-to-SYS price convergence rate, meaning the need for such contracts is simply low at present for participants.

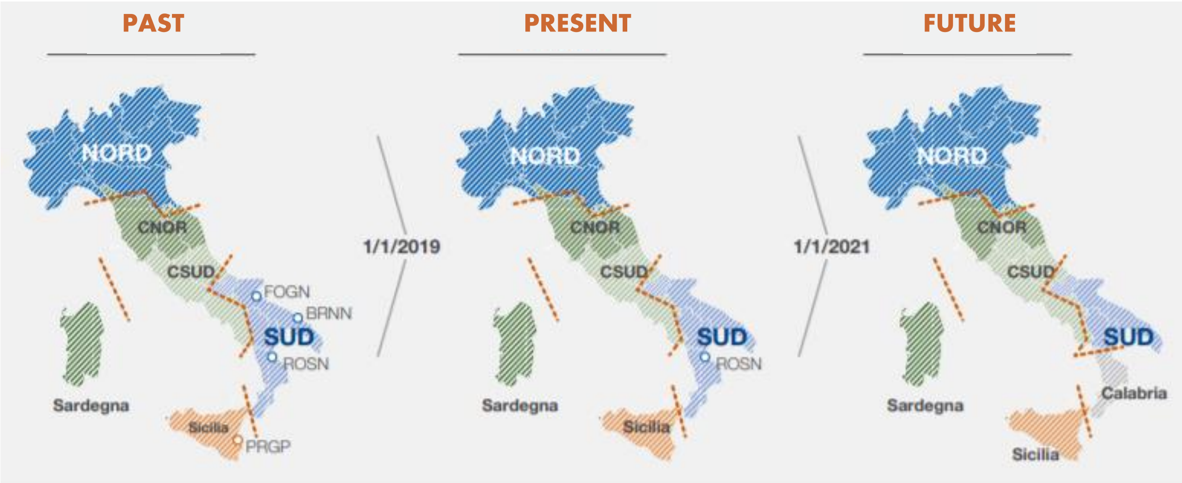
- In a letter addressing market functioning in the Nordics (Energimarknadsinspektionen, 2017), the CEO of Svensk Kraftmäkling (SKM, a major regional brokerage company) supported the fact that the short-term liquidity drop following Sweden's split was to be expected, but that overall liquidity levels remained 'good'. He then clarified that the steady decrease in derivative trading from peak levels observed back in 2002-2008 was due to several factors: "*reduced number of market participants, mainly financial residents in London due to financial crisis 2008, sharp increase of regulations in financial markets MIFID 1 and 2 creates high thresholds for new companies to establish themselves in the market and increased costs for existing players, the general decline in energy prices in the world has reduced the interest in energy investments as well as reduced consumption and production".* These conclusions have also been endorsed by Ei, for which the strict monetary requirements imposed by the MIFIDs pushed many participants out of exchanges and towards bilateral/OTC contracts.
- The strong renewable integration in the Nordics depressed wholesale prices and contributed to many thermal plants dropping out of the system (insufficient margins). Thus, another cause for the decline of liquidity on exchanges could have been a shift to subsidy-driven, out-of-market investments (hedging through bilateral contracts such as Power Purchase Agreements). Other external factors such as the implementation of the EU Emission Trading Scheme (ETS), the 3rd energy package and the influence of hydro years might also have contributed to the shape of Figure 9.

Note, finally, that market concentration has remained quite high in the Nordics (especially Norway), but in terms of market power abuses, NASDAQ OMX Market Surveillance has not witnessed significant issues post-2011.

3.2. Italy

Ever since its liberalization in 1999, Italy has been running a somewhat peculiar market organization when compared to the rest of the EU landscape. The regulator ARERA decided to divide the country in several price zones in order to better embed the scarcity of the network infrastructure in the market results. This was particularly relevant given the fragmented and stretched geography of the territory, which causes difficulties in optimizing energy flows. The zonal configuration is defined by the TSO Terna based on demand and RES clustering and reviewed every 3 years as part of the national Network Development Plan. The only liquidity criterion used in the review process is related to the strict definition of liquidity, i.e. the sensitivity of price with respect to volume (how steep new zonal merit orders would become).

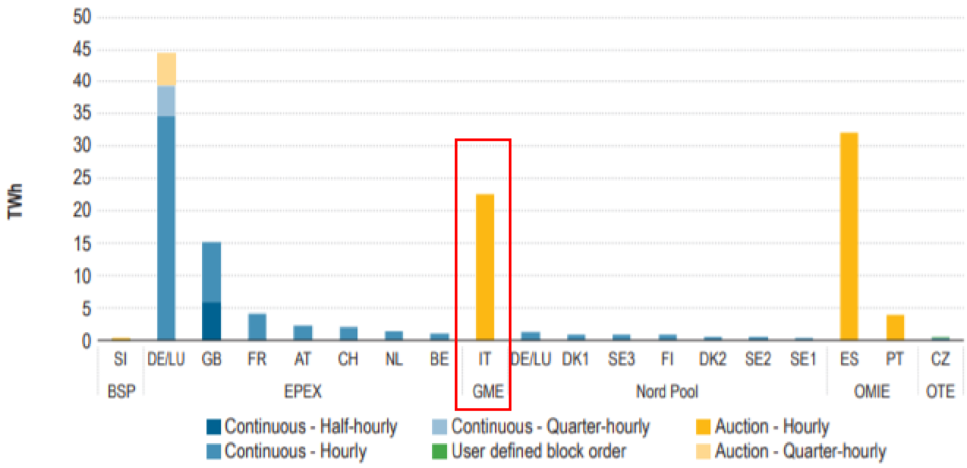
There are currently six zones, namely NORD, CNORD, CSOUTH, SOUTH, SICI and SARD, although a 7-zone reconfiguration approved by ARERA is planned for 2021. In addition, Italy used to have four limited production poles (FOGN, BRNN, ROSN, PRGP) where the interconnector capacity would be lower than the total local generation capacity and where additional congestion could arise. As per Figure 10, these are being removed thanks to continuous network development.



Source: (Terna, 2020)

Figure 10 : Evolution of the zonal breakdown in Italy

The way these zones contribute to creating different price regions in the Day-Ahead market is also atypical. While generators are classically remunerated at their zonal price, buyers must pay a single price across the country also known as *"Prezzo Unico Nazionale"* or PUN. The PUN corresponds to the demand-weighted average of zonal prices and is computed iteratively by the clearing algorithm Euphemia when determining the bids that are accepted or rejected (NEMO Committee, 2019). Later, participants can readjust their positions in the intraday market (MI) through seven consecutive auctions, and soon also via continuous trading. This time, the zonal price is applied to both supply and demand with strict anti-arbitrage measures in place. In 2018, the Italian intraday market was the third most liquid, following Germany and Spain. See Figure 11.



Source: (ACER, 2019a)

Figure 11: Intraday-traded volumes per BZ in 2017 (TWh)

Finally, the balancing market (MSD) is organized by Terna (who acts as a central coordinator) to ensure physical delivery and more specifically to solve any remaining intrazonal congestion. In order to do so, another series of discrete auctions based this time on a nodal approach are used. Participation is mandatory for all qualified units, which are remunerated on a pay-as-bid principle for their services. Both intraday and balancing trades come in the form of multi-part bids (complex orders with technical and financial parameters), settled during multiple auction rounds. These orders tend to yield more efficient economic outcomes when compared to simple or block bids: "*aggregators and utilities […] obtain from each auction round a precise and least cost generation pattern that could be directly nominated to the TSO and thus […] enhance the quality and reliability of information available for efficient and secure system operation"* (Neuhoff, Ritter, & Schwenen, 2015).

To reduce their exposure to price movements, market participants can either trade short-term physical products in the Daily Products Market (MPEG) and long-term financial products in the Forward Electricity Market (MTE). Within the Italian market, hedging the transmission risk can only be achieved via FTR Obligations. These are known as 'CCC' and allocated by Terna since 2004 through annual and monthly auctions based on internal capacity calculations. Note that the CCCs are settled Zone-to-PUN, which means that, like the Nordic EPADs, the regional transmission risk can be hedged against a more liquid price hub. On the other hand, to align with neighbouring countries, hedging on interconnectors with France, Austria and Slovenia is achieved through PTRs.

Although liquidity in Italian forward markets is unsatisfying according to some metrics (e.g. churn levels below 300 percent), it remains above than average in the EU. Despites its modest size and its large deployment of renewables, it features the second lowest bid-ask spreads (0.18€/MWh for 2021 Baseload products (ACER, 2020)). Liquidity was never a critical aspect in the development of the Italian market, nor did it seem to have been largely impacted by the national zonal review. The country has remained focused on promoting a sound and efficient market organization, while concentrating liquidity where it matters. It has drawn a lot of inspiration from the US market designs, in particular with its FTR design and auction-based nodal balancing market.

3.3. DE-LU-AT

The former bidding zone composed of Germany, Luxembourg and Austria was first set up in 2002 and regarded as the largest, most liquid hub by far in the entire European Union. In December 2016, ACER took the decision to disjoin the DE-LU and AT regions at the Austrian border due to rising issues with congestion management. In particular, the following topics were debated:

- Favourable wind conditions in Northern states have so far led to the build-up of a very large wind production pocket in the region (both on- and offshore). Because Germany's largest demand is located in industry-heavy Southern states, the electricity has to be transported across the country - which has proven very challenging due to lagging internal grid development. As a result, an increasingly large amount of redispatch actions and curtailment have been committed by German TSOs over the years. In 2017, the DE-LU-AT zone was responsible for more than half the total cost of redispatch in the EU (ACER, 2019a).

Source : (BundesNetzAgentur, 2019b)

Figure 12: Cost for system services from 2014 to 2018 and unplanned loop flows in 2018

- The large volumes transiting to South Germany create undesirable loop flows in adjacent countries (mostly CZ and PL). These flows arise from intra-zonal exchanges: they are therefore not accounted for in the day-ahead market results and are difficult to predict without tight coordination. In turn, they create the need for curative measures from foreign TSOs.

Interestingly, and although exchanges between Germany and Austria did contribute to the problem, most issues were internal to Germany. In theory, sufficient upgrades in German transmission infrastructures should have solved the issue, but due to the investment lead time, first reliefs were not expected before 2024. Discussions on a possible DE-AT split were filled with concerns that it would destroy the low bid-ask spread (~0.1€/MWh) and high-churn (above 800 percent) zone while creating a more isolated and illiquid market (AT). The BZR also concluded the split would cause a liquidity drop and an increase in market concentration. See Figure 13.

	DE/AT Split
Change of HHI per concerned bidding zone	DE: + 25 % AT: + 370 %
Change of RSI* per concerned bidding zone	DE: – 12 % AT: + 3 %

Source: (ENTSO-E, 2018)

Figure 13 : Forecasted change for the Herfindal-Hirschmann Index (HHI) & Residual Supply Index (RSI)

Yet, given the situation, the split officially took place in October 2018 after the BZR, and the DE-AT border saw its transfer capacity fall from infinity to 4900MW. Moreover, the Phelix DE/AT energy future, whose previous underlying was the single zonal price, was readapted so be settled on a 9:1 weighted ratio between the DE and AT average prices. Due to the ratio being overly weighted towards Germany's side, the contract's correlation to Austrian prices became a lot poorer, especially with more price decoupling due to reduced interconnectivity. Very quickly, this created additional costs for the Austrian participants, and significant price spreads between the two newly created future markets (5-10 €/MWh) emerged (EFET, 2019a). FTRs had to be introduced on the DE/LU-AT border in order to ease the issue. While traders blamed a rushed reconfiguration procedure, the Austrian TSO APG even joined a consortium against German TSO Tennet for a case of capacity withholding and anti-competitive behaviour (Verbund, 2019). Similarly to the 2010 Swedish case, Tennet is accused of attempting to reduce its internal congestion by artificially reducing the amount of cross-zonal capacity offered.

Despites these observations, the preliminary reports from BNetzA showed that redispatch costs fell to 1.2B€ in 2019 (BundesNetzAgentur, 2019a), which equals to a 17% reduction or 240M€ savings for consumers. Moreover, the pure congestion-related costs fell by 38% from 2018. In its later report, (ACER, 2020) confirms a 5.2% increase in DA traded volume and 7% for the IDM, alongside a 25% churn increase for AT and a progressive drop in bid-ask spreads (-63% in AT, -16% in DE). Because the split is still very recent, these short-term results should however be interpreted with care.

3.4. Conclusions

The review of these 3 cases leads us to the following conclusions:

- There is no clear evidence of a direct liquidity deterioration case for smaller BZs in the Nordics and Italy. In fact, liquidity never was a primary concern, neither during the Nordic split nor in the Italian zonal review process. Besides, the more recent DE-AT split has shown signs of weaker liquidity in the short-term, but mostly due to unpreparedness, and the situation is rapidly recovering.
- With the exception of Italy, these splits have been performed *reactively* to regional issues and ultimately motivated by an abrupt political decision. Thus, the execution timeframe granted to deliver these new configurations after the decision was likely too short.
- The underpinning issues seem more closely related to a lagging ability of national regulators to *preventively* re-evaluate and recast market rules to adapt to the reconfiguration. This also highlights the need for a broader, pan-European framework.

4. Recommendations

Based on the current status quo and the results of both the fundamental and empirical analysis, this section derives a set of recommendations to mitigate the possible downturn on liquidity from smaller BZs.

4.1. Increase the efficiency of spot markets

The expectation of lower liquidity levels in smaller BZs is generally based on the rationale that having more zonal prices and more volatility will fragment the (forward) market. Yet, physical (spot) markets must embed an accurate view of the physical system in order to provide meaningful price signals for consumption, production and investment decisions. Hence, apparent simplifications in the representation of the grid made at the day-ahead and intraday market stages come with a trade-off: they create inaccuracies which must be resolved later at higher costs, via less coordinated and less transparent congestion management mechanisms.

Ultimately, from a theoretical point of view, nodal pricing is the safest and most efficient design for physical markets. However, this organisation is still a long shot for the EU due to many political and regulatory barriers.[6] Instead, the way forward is likely to follow a refinement of the zonal market view by integrating more and more of the transmission network constraints via smaller BZs. Meanwhile, it is essential to remember treating forward markets not by how large they are, but by what they are: derivative markets. Forward prices reflect the expectation of the spot prices and as such should be designed *after* and *around* spot markets. As suggested in (Hogan W. W., 1998), getting spot prices 'right' in electricity markets is paramount. 'Right' (efficient) spot prices will reflect scarcity in transmission, and as such they will show more volatility. In this respect, higher volatility should not be perceived only as a flaw of smaller BZs.

There are two main reasons why prices would vary to a greater extend:

- Structural congestion being priced in: Splitting BZs results in less geographically homogenous prices on average. Given the existing network infrastructures (which may evolve), some new zones will become import- or export-constrained. These Zone-to-Zone price variations are a direct consequence of moving towards 'getting prices right' and should simply be interpreted as a signal for transmission resource shortage;

- Price robustness and sensitivity: In a smaller trading pool with fewer participants, the aggregated supply and demand curves become more erratic, which in turn can affect price formation. This relates to the notion of price sensitivity: prices are said sensitive if minor, non-fundamental input changes to the clearing algorithm can influence them significantly. Highly sensitive zones may be difficult to handle in the short-term without adequate tools (see next section).

Further, having some volatility is also a fundamental signal that market participants require more flexibility. It opens business opportunities for flexible assets to step in, especially as more and more thermal capacity is replaced by intermittent renewable production.

Yet the extent to which efficiency improvements can be made is very much dependent on the exact reconfiguration. The search for a zonal configuration that can capture the main benefits is an experimental problem which requires to find a set of long-term delineations across which most of the congestion can be captured. It is a challenging task which must consider current structural behaviours as well as future development in generation, demand, transmission and associated technologies7. Notwithstanding the methodology, there are certain characteristics that should be found in the newly created zones, such as sufficient interconnectivity. This is a key requirement from the CACM to avoid islanded regions with weak competition. In addition, a truthful (non-derated) reporting of available cross-zonal capacity by TSOs is necessary to optimise the market dispatch. The recent decision of the Clean Energy Package to increase to 70 percent (from 20 percent) the portion of the lines' total capacity allocated to cross-zonal trades addresses this issue partially. As smaller BZs tend to rely proportionally more on cross-zonal trades, this should prevent them from being stranded or overly manipulated. On the other hand, it is more challenging for large BZs dominated by internal trades to be able to offer such an increased volume to the market (since the 'real' physical capacity is already partly filled with loop flows from internal exchanges). For those, TSOs will most likely have to offer artificially high volumes to satisfy the rule and apply additional

[6] Note that the target model does not exclude the possibility of a nodal pricing mechanism.
[7] For instance the deployment of innovative flow control apparatuses such as advanced Phase Shifters.

remedial actions during redispatch, thereby creating extra costs and incentives for a more efficient configuration.

With a more detailed and volatile spot market, it is all the more important for participants to be able to easily rebalance their position before delivery. As renewable penetration grows, this becomes even more crucial. For the moment, many intraday markets rely on continuous trading where time lag and low orderbook depth can make it difficult to do so. Complementing this market with auctions – possibly with stronger cross-border participation – would help concentrating liquidity at regular intervals and increase short-term efficiency. See (Tractebel & Sweco, 2019) for a more general discussion on the need to introduce auctions in the intraday market.

4.2. Improve forward hedging mechanisms

At the root, financial markets enable energy companies to manage their risk exposure to spot price volatility. Risk management should not take precedence over getting prices right, and it makes less economic sense to design a zonal configuration around minimizing the agents' direct exposure to market risk. Indeed, if agents are not exposed, the underlying risk of physically delivering electricity still exists and is simply incurred out-of-market, in a less transparent and competitive way and financed by the final customer. The goal is then rather to provide market participants with an acceptable level of risk at acceptable cost (DNV-GL, 2020). Forward markets should feature adequate products and be liquid *enough* to address the very important concerns raised by the market participants in the 2018 ENTSO-E report . This is directly reflected in the Electricity Regulation which refers to "economic efficiency" as something to be maximised in the BZR context (e.g. article 14.1) while it refers to "liquidity" as something to be ensured (rather than maximised, preamble 19). In other words, it is preferable to have an imperfect hedge on a "right" spot price rather than the contrary.

In MSs which previously split, forward liquidity matters did not seem to have provoked decision-changing consequences. Yet, it is clear that many other MSs are currently running forward markets that may not be able to sustain acceptable hedging costs with smaller BZs. Further splitting will lead to the fragmentation of basic energy products to an extent where many become less liquid and where price correlation between zones may decrease, thereby preventing the sole use of a proxy. As more and more transmission is priced in the spot market, firms' risk management can no longer focus on the basis (energy) risk only. Having complementary transmission hedging products becomes essential.

4.2.1 Financial over physical LTTRs

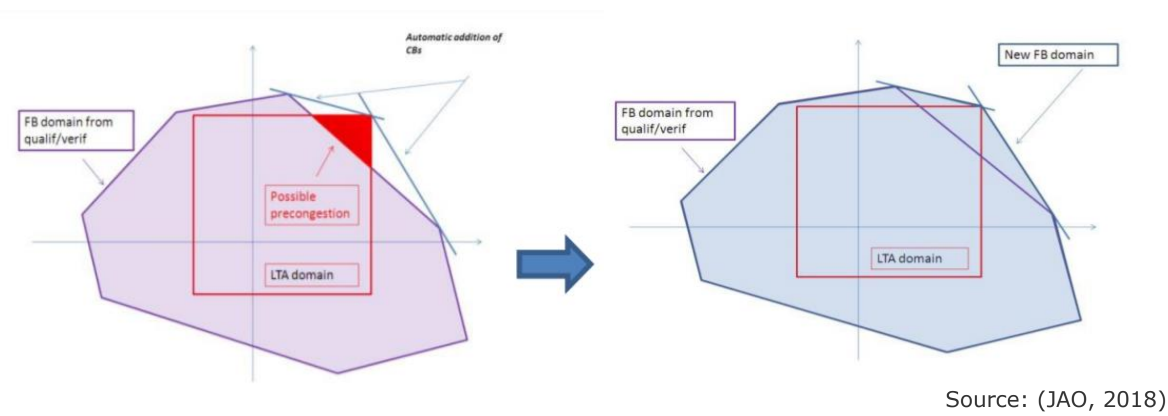
Currently, PTRs are still used by some MSs on their borders[8] while they tend to result in inefficiencies. Since PTRs entitle the holder to a physical carve-out of the interconnector capacity, the hedged volumes must be nominated prior to and discounted from the day-ahead market (JAO, 2018). This means that some of the cross-zonal transmission capacity is reserved for physical delivery prior to day-ahead market coupling (performed via a shift of the Flow-Based Domain). In practice however, nomination rates of PTRs have been historically low, partly due to the fact that it is only needed when closing a physical position. Most traders would rather hold onto the PTR until delivery and resell it at the price spread instead of nominating. This means that PTRs effectively corresponds to contracting a financial LTTR when under perfect market

[8] See https://www.jao.eu/support/resourcecenter/overview for the exact list.

conditions. In situations of scarcity however, PTR holders have a stronger incentive to nominate in order to circumvent the shortages on the DAM. Participants exploiting this backdoor can worsen the security of supply issue, as it leaves the day-ahead market with tighter transmission capacity and weaker price formation due to lower residual liquidity (Frontier Economics, 2016). In addition, the PTR nomination process may result in 1) additional costs as an extra step of the coupling process and 2) early and perhaps less accurate curtailment of PTRs by TSOs. Meanwhile, FTRs have proven to have better economic properties (Joskow & Tirole, 2000) and require no nomination since they are cashed out directly on the day-ahead market. They entitle holders to a simple cash-flow based on the market results and do not curtail cross-zonal capacities. While financial rights are generally foreseen by the FCA GL, only one product type is allowed on each interconnector. We therefore see it necessary to first **pursue and complete the phase-out of PTRs in favour of FTR Options**.

4.2.2 Foster competition for transmission capacity

Another hindrance lies in the fact that competition for transmission capacity is weak under the current design of LTTRs. The related TSOs define the volumes they are willing to offer for each interconnector separately. The interactions between the amounts made available on different borders are thus generally not considered. This can result in 1) less capacity being offered overall (cf. NTC vs FB representations) and 2) allocation schedules that may not always be simultaneously feasible (leading to local infeasibilities and curtailment in a physical network representation). The absence of interdependence for these LTTR auctions by means of a single clearing with a better network representation produces a sub-optimal allocation whose costs are socialised through network tariffs. It may also lead to distortions between the volumes offered forward and the ones the network can accommodate at delivery. With too few LTTRs, liquidity and hedging opportunities are withheld from participants. Conversely, if too many LTTRs are offered, TSOs become revenue inadequate (the sole congestion rent cannot fully fund the sales, and the firmness costs increase because LTTRs must be curtailed). In order to guarantee such revenue adequacy, the current practice is to further increase the remaining transmission capacity of interconnectors until all contracted LTTRs can be included in the dispatch. This forced inclusion - known as the Long Term Allocation (LTA) inclusion - is represented in figure 7 and can lead to more infeasibilities in real time.

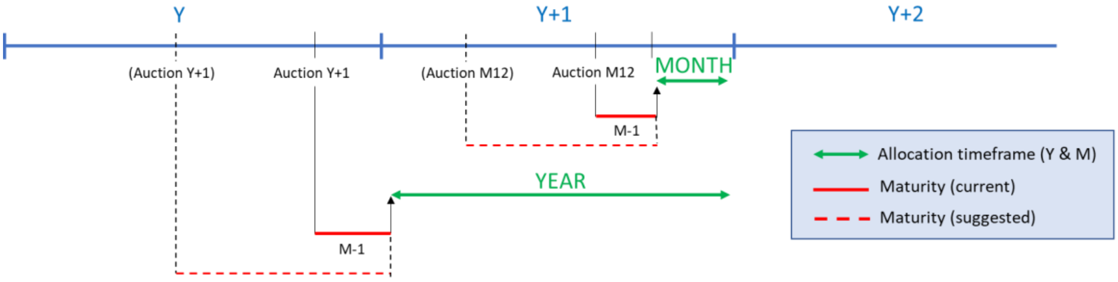


Source: (JAO, 2018)

Figure 14 : Inclusion of the LTA domain in the DAM feasible region

In US systems, the allocation of FTR is centralized in a single auction, repeated at different timeframes and constrained by the same network view as the DAM. This design maximizes the amount of transmission rights sold, while producing allocations that are network-compliant (based on forecasts at the time of the auction). Likewise, **the**

integration of forward markets in the EU can be reinforced by setting up a single Flow-Based clearing of LTTRs. The latter would increase competition over the same network capacity, and concentrate liquidity. A centralized allocation via a unique and periodic bid-based auction relying on a Flow-Based network representation could be organized. In such a setup, each transmission link would compete against the wider system and the capacity would be allocated to the highest bidders. TSOs would continue to collectively be responsible for the remuneration of LTTRs and for bearing the financial counterparty risk. They would also need to provide JAO with the additional network data pertaining to the Flow-Based representation. Central auctioning would optimise the volumes sold by making FTRs more network-compliant and thus improve the revenue adequacy of TSOs. Indeed, the latter would not need to artificially enlarge the Flow-Based domain in the DAM as much, and would thus commit lower redispatch costs close to real-time. The success of this organisation is also conditioned by the ability for participants to readjust their portfolio regularly. This can be addressed both by offering **additional FTR maturities**[9] (month-ahead, year-ahead, multi-years, etc.) and by improving resale through **secondary markets** (EFET, 2019b).



Source: Tractebel Impact

Figure 15: Allocation timeframe vs product maturity

A better alignment of FTRs with standard future (energy) contracts should increase the synergy of the two products and facilitate hedging.

The Flow-Based representation is in line with the main objectives of the CACM since it improves competition, the use of the transmission infrastructure and its allocation. Article 10 of the FCA GL also states that, while the ATC methodology is the current standard, "*all TSOs in each capacity calculation region may jointly apply the flow-based approach for long-term capacity calculation time frames*" provided it "*leads to an increase of economic efficiency in the capacity calculation region with the same level of system security*". Since the added value of the Flow-Based calculations lies in capturing network interactions, the case is therefore stronger if the auction encompasses the entire Single Market area. Yet, it may be relevant to preserve concurrent regional products such as EPADs & CCCs as long as they prove at least equally efficient to this new approach (which is the legal requirement for their existence).

4.2.3 Make the products more resilient to zonal splitting

It is important to acknowledge that certain design features of these hedging products play an important role in their efficiency and liquidity. We have just mentioned how a Flow-Based allocation of FTRs could improve forward cross-zonal risk management activities. Yet, the current implementation of FTRs in the EU diverges from the original FTR design, as established in US markets (Duthaler & Finger, 2008). The main difference

[9] Note that ENTSO-E has launched a consultation on this topic upon participants' request, with a proposal to implement block bid auction at a monthly granularity: https://consultations.entsoe.eu/markets/blockbids_new_approach_lttrs/consult_view/

being that EU FTRs are sold as Options rather than Obligations (no downside for buyers), and that they are not offered directly **Point-To-Point** (between any two zones in the network), but rather to parties "on both sides" of a specific interconnector. In other words, they remain line-dependent: this is the "flowgate" concept. An agent willing to arbitrage between two distant zones would have to purchase a portfolio of EU-FTRs across all possible paths. On the other hand, the Point-To-Point FTR enables participants to simply specify a source and a sink and capture the price spread between the two. In nodal systems for instance, many zones (nodes) are quite illiquid and volatile, which makes hedging between two such neighbouring nodes ineffective. Instead, the FTR is bought between the local node and a remote node (or 'hub'), which features greater liquidity. This hub can be a real node or a synthetic aggregation.

Some of these US features are already present in the Nordic and Italian markets. In the Nordics, energy is sold forward on the system (SYS) price hub, and EPADs are sold continuously on financial markets to hedge the Zone-to-SYS transmission risk. In Italy, energy is served at the PUN price, which is a national arithmetic average of the zonal prices earned by resident generators. The resulting price spread can be hedged via CCCs, which are in essence FTR Obligations allocated by Terna based on a network capacity calculation. On top of both having a centralized procurement, these instruments are not line-dependent and rely on a price hub (SYS and PUN respectively) as a liquid proxy, which benefits the entire ecosystem. However, these regional features are not implemented anywhere else in the EU, which means some MSs might be exposed to worse liquidity going forward.

A first scenario would be to assume that further splitting would result in local liquidity shortages for some LTTRs (on specific borders), while still maintaining sufficient liquidity for energy in some other zones. In this case, hedging energy on a proxy zone or hub remains possible, but the remaining transmission risk over the concerned borders could become too costly to hedge, due to poor liquidity and participation. The **current line-dependant FTR design could then be recast into Point-to-Point FTRs** which would no longer need to be defined on a specific physical path but would only require sink and source zones. Point-to-Point FTRs improve the ability for participants to hedge against more remote areas and give traders access to a wider range of trading pairs (spreads between any two zones). These contracts would still be backed by the underlying physical network capacity, although the theory shows the equivalence between a point-to-point FTR and its linear combination of contract path is mathematically more challenging with Options (Hogan W. W., 2000). **Obligation FTRs**, on the other hand, provide a complete hedge in both directions, which facilitates the netting of line contributions in the computation of the full Point-to-Point right. This would also increase the volumes of rights offered (ENTSOE, 2012) and simplify the Flow-Based clearing by turning the bids into simple bids for injection and withdrawals of energy at different network locations. Lastly, Obligations shift part of the financial risk from TSOs back to holders which could 1) reduce hedging costs for buyers (lower premiums than options due to potentially negative pay-outs) and 2) improve the revenue adequacy problem for TSOs (reduce total payments since some holders will pay back the congestion rent). Yet, options are probably less commercially complicated and can still be more attractive to some hedgers since they do not entail any negative pay-outs.

It could also be that the extent of the zonal splitting would eventually leave very few to no liquid zones (cf. nodal system). In this case, it is not only the transmission products, but also the energy ones that are at risk of being inadequate for hedging. Such a situation would require to somehow recreate liquidity pools. By borrowing the US concept of "hub", regional synthetic liquidity pools built on aggregated zonal prices could be envisioned. When using FTRs, hubs backed by physical prices have the double advantages of:

1) Being compatible with a 'Flow-Based' procurement as they can be decomposed into contributions from individual injection points (not the case of the Nordic SYS price for instance, but by design EPAD volumes do not need to be checked against the network since they are not offered by TSOs);
2) Retaining higher correlation with physical zonal prices: if the transmission premium in the concerned zones were to increase significantly (structural congestion, excess of renewables), an average price would scale linearly and be a more resilient hedge than a congestion-free system price.

For instance, a 'CWE-average' price has already been discussed in (ACER, 2020). Participants could connect to such a liquid hub to hedge their energy, and use a **Zone-to-Hub** FTR to capture the remaining price spread. As long as this hub can be decomposed into the different physical contributions of its underlying BZs, the FTR remains backed by the TSOs' capacities and the Point-to-Point framework still holds. As an example, a 1MW FTR 'DE1-to-CWE-average' would be represented as a 1MW injection from subnational zone DE1 and a 1MW withdrawal spread by weight across all zones making up the CWE-average hub according to their contribution. Also note that a Zone-to-Zone FTR can be recreated by combining two Zone-to-Hub FTR if need be (Zone1-to-Hub + Hub-to-Zone2). These features could improve the functioning and resilience of transmission risk hedging under smaller BZs and with evolving configurations. **Ultimately, the goal is to achieve "small enough" physical markets to form efficient short-term prices, and "large enough" forward markets to bring the necessary liquidity for hedging and price discovery.**

Yet, hedging in the context of investments in additional generation capacity can typically require to consider longer time horizons (i.e. 10 years or more), which current hedging products do not cover. Consequently, any decision on the type of hedging mechanisms is to be seen, at least at the moment, from the viewpoint of an existing asset, rather than as tools to lock in revenues and costs throughout the complete investment period.

To attract investment, a stable, solid and forward-looking regulatory framework (also for hedging products) may be more important than the ultimate choice of the hedging mechanisms, for which different options exist. In this respect, the existing ones, at least in Continental Europe, do not seem however, very resilient to changes, e.g. they do not seem to cope well with changes in bidding zones, as opposed to the instruments available in the Nordic and/or Italian markets. It is precisely this lack of resilience to changes what makes any change in bidding zones rather unattractive for many market participants. Attracting participation liquidity over these longer timeframes remains an open issue, tentatively addressed by national capacity remuneration mechanisms (CRMs). Some solutions have been suggested by traders to increase participation, such as the creation of mandatory Virtual Power Plants (VPPs) whereby generators would be forced to offer part of their production to the market, but their applicability goes beyond the scope of this report.

4.3. What about market power?

Lower liquidity as a result of smaller bidding zones is often claimed together with a higher risk of market power abuse. In fact, smaller BZs can have consequences on the conditions to access the market and on the incumbents' behaviour. A first fundamental effect of smaller BZs is the reduction in the number of market participants in each new (and smaller) bidding zone. It is therefore intuitive to argue that market power exercise tends to be more profitable and thus more likely. In the First Edition of the Bidding

Zone Review ((ENTSO-E, 2018)), the analysis mainly relies on the traditional Herfindal-Hirschmann Index (HHI) and the Residual Supply Index (RSI) to assess market concentration and market power. However, this is a very static and simplified way of looking at market behaviour. ENTSO-E mentions indeed that these concentration indicators are used as a proxy for market power, but it is not clear to what extend market power would actually be abused. More generally, market power abuse is not only a question of market concentration, but also on the generation mix and the structure of the demand. Also interconnections and thus competition from outside the bidding are commonly omitted from the calculation. This brings us to the question of the relevant market area to consider when assessing market power issues.
The question of the relevant market is not straightforward. Obviously, the reason for a bidding zone split is typically a structural congestion. However, this does not mean that congestion is happening always and on all interconnections. Market participants even in smaller zones can thus be disciplined by competition from "abroad". This argument can even be reinforced. (ACER, 2014), based on (Harvey & Hogan, 2000), argues that smaller bidding zones actually support competition: grid constraints are better reflected, allowing for reduced security margins and an overall larger part of the transmission capacity is made available to the market. On the other hand, it is not that larger bidding zones annul congestion. Sooner or later, the physical constraints of the grid must be respected. If the market does not properly take care of the grid constraints, it has ultimately to be addressed by the redispatch mechanism where dominant players may exercise market power given their location in the system.

Overall, it appears therefore that market power is a locational issue whose roots are independent of the zonal configuration (Pototschnig, 2020). Already back in 2014, (ACER, 2014) concluded "*that the review of bidding zones should not be primarily guided by possible impacts on market power*."

This does not mean that market power in general is not an issue. We argue that possible market power abuses become more easily detectable in a transparent spot market, as opposed to a rather opaque redispatch mechanism. However, in most European power markets today, bidding is portfolio- rather than unit-based. Since the units of this portfolio can potentially be distributed over the bidding zone corresponding typically to a country, it becomes very hard to establish a link between bids and costs, especially in case of block bids. This is one reason why today, market power mitigation in Europe is mainly ex-post rather than ex-ante. This makes detecting and proofing market power abuses not only difficult but it also is a time-consuming process. Note, on the other hand, that the framework for an ex-ante market power monitoring is provided in the European legislation. In fact, the EU's competition policy for wholesale power markets is based on the Regulation on wholesale energy market integrity and transparency (REMIT). REMIT forbids market abuse (Article 5) and requires market monitoring by competition authorities and power exchanges. While REMIT sets the right framework for addressing market power concerns in wholesale power markets, it leaves room for implementing a market power mitigation and detection mechanism at national level. Also it does neither specify the tools to be applied nor the process for a day-to-day market surveillance. The CACM Regulation, on the other hand, is more precise with respect to the collaboration between NRAs and power exchanges, since it requires Nominated Electricity Market Operators (NEMOs) to have "*appropriate market surveillance arrangements in place*". Hence, the framework is there but the tools are missing. With smaller bidding zones, portfolio-bidding will naturally become less relevant over time, but the granularity will probably not be fine enough yet in the medium term to allow for a more efficient ex-ante monitoring. Among the many tools

NRAs have at hand to intensify their monitoring, the introduction of a location-based[10] bidding could be contemplated to address market power issues in a more efficient ex-ante manner. It would also provide additional information to system operators when calculating generation shift keys, to further improve the use of the network.

Conclusions

The optimal definition of the BZs is a cornerstone of a well-functioning zonal European electricity market, as set out by the CACM. Originally, the BZ configuration was largely based on national borders and became the natural foundation on which the EU started work on the delivery of its Target Model. Nowadays, partly because of a growing demand coupled with lagging network development and large policy-driven integration of renewables, this organization is becoming increasingly inefficient to sustain.

- **The pricing of the transmission externality must be improved on physical markets**: increasing levels of congestion, curtailment and loop flows cannot be fully treated by a market that is transmission-agnostic over extended geographies. Large BZs create equally large simplifications of the physical network, which pressure TSOs into contracting large amounts of redispatch actions to realign in real-time. The costs of such actions are in turn borne by end consumers in the form of network charges.
- **The hedging of the transmission externality must thus be improved on forward markets**: with the exception of the Nordics, explicit Long-Term Transmission Rights are auctioned independently on each cross-zonal pair based on ex-ante TSO estimations. This lack of coordination may create mismatches with what the network can truly accommodate and increase the firmness costs incurred by TSOs. This organization features low liquidity and scalability.

Smaller BZs, since they embed more of the transmission risk into the market, are often regarded as the most promising candidate to solve the first of these two aspects. By design, they increase the locational information of spot prices and also tend to enhance cross-zonal competition on these markets. Their impact on the second aspect is in contrast more uncertain. The accrued volatility of spot prices intensifies the hedging needs of risk-averse market participants against that same transmission risk. Under the current organization, more zones would translate into more fragmented, possibly less liquid forward products. Absolute liquidity drops have indeed been locally observed in some MSs where smaller BZs were implemented, but it is delicate to disentangle the direct effect of smaller BZs from other external factors such as changes in the regulatory landscape, in price correlation levels or in overall appetite for energy investments.

This study covered extensively the following aspects: the economic implications of smaller BZs and the relevance of liquidity for a well-functioning market, the lessons that can be drawn from historical bidding zone splits, and what mitigation measures could be implemented going forward with more bidding zones. In general, we concluded that the search for the optimal BZ configuration should aim to make (spot) prices right first, before attempting to minimise risks on derivative (forward) markets. However, forward markets should be made more resilient to BZ reconfigurations before extensive splitting so as to reduce socialised disruption costs and retain the trust of investors.

[10] Note that a location-specific bidding is less restrictive than a unit-based bidding. It stills leaves some flexibility to the operator to use the various units that might be located in the same node.

In this regard, **we provide a set of recommendations:**

Recommendation	Legal framework and policy options
1) Pursuing and completing the phase-out of PTRs in favour of FTRs.	FTRs are allowed by the FCA GL and already fully cover internal CWE borders. However, their utilization as a default LTTR is not a requirement yet. Setting an implementation roadmap or a review process in the FCA GL could speed up adoption (which is equivalent to a phase-out of PTRs).
2) Centralized Flow-Based allocation of FTRs.	JAO is already the central allocation platform. Gathering the FTRs under a central auction would be aligned with the CACM and FCA GL. The extension of the Flow-Based calculation from Day-Ahead to forward markets is possible according to the FCA GL. However, the FCA GL should emphasize that FB allocation in LTTRs should be the default where FBMC is used in DAM. Art. 10 should make this more explicit. TSOs remain responsible for the capacity calculations.
3) Improve the ability for participants to readjust their positions more regularly, via longer LTTR maturities and secondary markets.	Presently, LTTRs are offered on yearly and monthly timeframes, each via a single auction (usually performed M-1 to delivery). Since the FCA GL and HAR do not restrict the maturity offered for LTTRs, the volumes for the same delivery period could be readjusted across several auctions rounds at different maturities, e.g. Y-1, Q-1 and M-1. It should be ensured that secondary markets can scale accordingly to provide continuous liquidity around the auctions and are aligned with future energy products.
4) Establishing a stable and transparent methodology to carry over ongoing contracts when BZ reconfigurations occur.	FCA GL only states via Art. 27 that LTTRs on outdated BZ borders must be reimbursed to holders at purchase price. This should suffice as long as the lead time preceding a reconfiguration exceeds the complete lifetime of the contract (time to maturity + duration of delivery), e.g. 2-3 years. If/when this is no longer the case, hedging positions can be compromised and the FC GL should include the requirement to elaborate a grandfathering or re-auctioning methodology.
5) Replacing 'flowgate' FTRs by a Point-to-Point (specifically, Zone-to-Zone) design to enable transmission hedging between any two distant zones. Obligations over Options can facilitate the decomposition of such contracts into individual network element contributions.	The FCA GL currently imposes that LTTRs be allocated on each bidding zone border via Art. 28-31, which precludes the use of Zone-to-Zone transmission rights. Zone-to-Zone FTRs should therefore explicitly be introduced in the FCA GL. Having Flow-Based calculation already in place would facilitate the transition from a technical point of view, especially if complemented by Obligations FTRs. In this regard, the FCA GL already allows both Options or Obligations FTRs, although the wider economic implications in the EU context should be further studied.
6) Expanding Zone-to-Zone into Zone-to-Hub FTRs by constructing synthetic price hubs based on aggregated physical zones to create regional liquidity pools.	The FCA GL does not make any provisions for synthetic hubs and Zone-to-Hub FTRs. Design requirements for synthetic zones would have to be established in the FCA GL (e.g. creation and validation process, rules for the determination of the contributions to price from underlying BZs, etc.). Within this organization, FTR-obligations are again more economically sensible.

The liquidity benefits of **recommendation 1** as a standalone measure remain quite modest (mostly in situations when DAM liquidity is very scarce). However, it becomes desirable leading up to a central Flow-Based allocation, i.e. **recommendation 2**. The latter allows to better capture the network externality at allocation level, which is a critical piece to improve forward competition and maximise the volumes offered. LTTR volumes thus become embedded in two central FB network calculations (allocation and DAM), for which PTRs are not really suited since they are normally nominated and removed beforehand.

Recommendations 3 & 4 aim at providing more flexibility to participants without drastic changes to the current legal framework. They do not necessitate the implementation of any other prior items, and should be viewed as part of a parallel timeline. Having these items in place is nonetheless important when transmission risk grows and more LTTR liquidity is needed along the forward curve.

Recommendations 5 & 6 build upon recommendations 1 & 2 and will likely require prolonged regulatory and implementation work, as they imply to change the very design of the product. Zone-to-Zone allows to directly access any remote zone with liquidity, thus further facilitating competition with the wider system. On this basis, a second layer of zonal aggregation can then be implemented: the 'hub'. It remains grounded to the physical system and its main feature is that it provides additional regional liquidity which is much less impacted by BZs reconfigurations. In general, our view is that this last transformation, alongside the central FB allocation of FTRs, have the most future-proof potential in terms of securing forward liquidity, and should be given priority attention.

In terms of **implementation**, two options are conceivable: the EC could support the development of an efficient hedging of the transmission risk by amending the FCA GL, in line with the recommendations presented above. However, such process may be time-intensive and may not be started immediately. Alternatively, recommendations 1 to 4 consist of specifications of the current provisions of the FCA GL. Those recommendations could therefore be implemented via terms and conditions or methodologies at the level of the Capacity Calculation Regions (CCR). At the same time, discussions could be launched on recommendations 5 and 6 - which are currently not foreseen in the legal framework - in view of amending the FCA GL once there is an agreement on the specific design choices (FTR-Options vs. FTR-Obligations, design requirements of synthetic hubs, etc.).

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