European Union Agency for the Cooperation of Energy Regulators

ACER POLICY PAPER

ON THE

FURTHER DEVELOPMENT OF THE EU ELECTRICITY FORWARD MARKET

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EXECUTIVE SUMMARY

The EU transition towards carbon neutrality and other structural shocks in the past few years have increased the uncertainty about the future electricity prices. This renders the focus on the forward electricity market much more important to be able to provide stability to stakeholders when making their investment and operational decisions.

In this paper, ACER revisits the functioning of the electricity forward market in the EU. We identify that existing electricity forward markets in the EU suffer from problems which prevent achieving the objective of an effective and efficient electricity forward market. The most prominent are insufficient liquidity, accessibility, competition and transparency as well as inadequate market structure.

In the short term markets, these problems have been partially addressed with the help of market integration, namely with market coupling where supply and demand from different bidding zones is simultaneously matched with the help of cross-zonal capacities. Market coupling successfully integrated national day-ahead and intraday markets to operate as a single integrated market. Although the existing long-term cross-zonal capacity allocation does integrate forward markets to some degree, we find that there is much room for improvement in the way these capacities are used to further integrate forward markets. We identified nine specific problems, which try to explain the main reasons why forward markets are not achieving the objective of providing effective and efficient hedging opportunities to market participants.

In order to address the identified problems and achieve the objectives, ACER proposes several improvements to the electricity forward market. Most of these improvements relate to a better allocation of long-term cross-zonal capacities in a way that integrates national forward markets into a more integrated regional or European electricity forward market.

ACER first proposes to keep the long-term transmission rights issued by TSOs as a default regulatory intervention and to impose regional coordination and harmonisation of the assessments and decisions of regulatory authorities by which they may approve a deviation from the default regulatory intervention.

ACER identifies two promising policy options for the type of regulatory intervention aiming to address the identified problems with better allocation of long-term cross-zonal capacities. These are (i) allocation of zone-to-hub Financial Transmission Rights by TSOs and (ii) improved allocation of long-term cross-zonal capacities by TSOs in timeframes up to three years ahead of delivery with a frequent auctioning and a secondary market. As a deviation from the default regulatory intervention, the option of market coupling with Contracts for Differences is also a promising alternative to long-term transmission rights. All those options can be complemented (if needed) by the addition of national market makers, further supporting the liquidity of forward markets in specific bidding zones.

In case TSOs allocate long-term transmission rights, ACER also recommends that these are allocated in a form of FTR obligations with a full financial firmness. At this stage ACER does not exclude the possibility of FTR options, which may be added only after careful evaluation of their impact on the efficient functioning of electricity forward market.

1. INTRODUCTION

1.1 Context

In the European Union, the electricity market design is based on bidding zones within and between which market participants can trade electricity in different markets for different timeframes. In the forward market timeframe, trading occurs from several years in the future up to two days ahead of delivery. The forward market allows market participants to stabilise and hedge their future cash flows and thereby secure their businesses against the risks of future price changes. The EU electricity market is undergoing a transition to carbon neutrality and the market has experienced structural shocks in recent years. This increases uncertainty about the future and renders the focus on the forward market all the more important.

The European electricity forward market appears to be struggling with many problems such as insufficient liquidity, accessibility, competition and transparency as well as concentrated market power. While the day-ahead and intraday markets already underwent a significant revision, harmonisation and integration with the introduction of single day-ahead and intraday coupling, regulators and policy makers are now focussing on the further development of the forward market. The only regulatory intervention at EU level, which is the issuing of long-term transmission rights ('LTTRs') by Transmission System Operators ('TSOs'), is not the product of careful evaluation of what is best for the market, but rather the remnant of the very beginnings of cross-border trade in the EU where TSOs started to explicitly allocate long-term capacities for trade between Member States. While the focus of LTTRs has gradually shifted from mere capacity allocation to cross-zonal hedging (by increasing the firmness of these rights and the introduction of the use-it-or-sell-it mechanism), the intervention itself remains essentially the same and its appropriateness has not yet been properly reviewed.

This paper outlines ACER's view on the future development of the EU electricity forward market. It does not aim to objectively quantify and back up all the positions expressed by the regulators. Rather it aims to support policy makers and stakeholders with general policy considerations backed by an initial impact assessment.

1.2 Scope

1.2.1 Price risks

The scope of this paper is to analyse solutions to hedge price risks. Considering the locational nature of electricity price formation, the price risks fundamentally arise from the uncertainty of zonal electricity prices – these are therefore the primary price risks. On the other hand, cross-zonal price risks arise from a combination zonal price risks – these are therefore considered as the secondary price risks. Therefore, if zonal price risks can be effectively hedged directly, there is no need for specific cross-zonal price hedging products.

1.2.2 Timeframe

We make a distinction between the timeframe up to approximately 3 years ahead of delivery and timeframe beyond 3 years ahead. We assume that the forward timeframe up to 3 years ahead is dominated by demand for hedging driven by operation namely electricity consumption and generation. Here, consumers selling their products or services ahead of time are interested to hedge the costs of electricity consumption and producers procuring their fuels ahead of time are interested to hedge the revenues of electricity generation. Beyond the 3-year timeframe, the overall interests of consumers and producers to hedge operation diminishes significantly. This also applies to electricity suppliers (retailers), which are faced with uncertain future portfolio of consumers due to the risk of consumer switching.

Nevertheless, the interest to hedge beyond 3 years is still very much important, partly to hedge operation, but most significantly to hedge investments, notably generation investments. As liquidity of forwards and futures drops significantly with maturities beyond 3 years, investors are seeking other means for investment hedging. One of them is roll-over hedging with futures up to 3 years maturity. Some investors seek state support mechanisms such as Renewable Energy Sources ('RES') support schemes and various Capacity Remuneration Mechanisms ('CRM'). In recent years, Power Purchase Agreements ('PPAs') have gained popularity for hedging investments. Such PPAs are long-term contracts with longer maturities under which an entity agrees to purchase electricity directly from an electricity generator. Those contracts are typically linked to the construction of RES projects and serve as a hedge for the investment. While all these strategies and instruments may have an impact on the forward markets up to three years maturity, the investment driven hedging is beyond the scope of this policy paper, because it would require a different analysis and set of solutions. Namely, some policy options presented in this paper are promising in terms of improving the functioning of forward market up to 3 years, but they are unlikely to have the same effect beyond three years maturity, since, inter alia, the fundamental interest of supply and demand for hedging beyond 3 years is still fundamentally lower and the counterparty risk is significantly higher. Therefore, investment driven hedging would best be addressed within another work.

1.3 Literature review

The broader context of forward markets is to hedge the risk of the uncertain prices and cash flows. In short-term electricity market, these prices have a strong locational dimension, mainly due to congestions. How these congestions are managed has a strong impact on short-term operational efficiency of the market, but also on hedging solutions. A common pattern found across all electricity markets is that hedging requires some sort of aggregation of supply and demand for hedging across larger areas (aggregation of nodes into zones or hubs or aggregation of zones to hubs) and organising forward market around such aggregates. The risk not covered by the aggregate hedging products (the difference between aggregate prices and specific locational price, i.e. 'the basis risk') is then covered by complementary hedging products.

In the European electricity market, the aggregates are constructed around bidding zones (or combination of bidding zones), whereas the basis risk can be covered by various transmission rights or Contracts for Differences ('CfDs'). Their application in different regions or borders in EU is summarised in the study of Economic Consulting Associates (2015).

The literature on electricity forward markets can be broadly fitted into three classes. The first studies the overall market design as a balance between the construction of aggregates and managing the basis risk. The second class of literature focuses on the functioning of the aggregated forward markets and the third class covers the functioning of the basis risk hedging.

Harvey et al. (1996) proposed a non-regulated aggregation hubs based on market preferences and node-to-node Financial Transmission Rights ('FTRs') to cover the basis risk between the nodes. As node-to-node FTRs may be quite illiquid due to large number of combinations, another option is to define ex-ante the exact aggregation and this allows to provide all FTRs from each node against the same predefined aggregation hub. This significantly reduces the number of different FTRs. The problem of how to construct such hubs in an optimal way was analysed by Borisovsky et al. (2009), having in mind that well-defined hubs may not need additional basis risk products if correlations between the hub price and nodal prices are high. All references to nodes above of course also apply to zones.

The second class of literature on the functioning of forward markets at aggregates is most widely represented, as it is the main forward market which covers the majority of risk for most market participants. This area focuses more on liquidity, competition, market structure and price dynamics and is less relevant for market design choices.

In the third class of literature on hedging basis risk we find mostly literature on transmission rights issued by system operators and other financial products between market participants, such as Contracts for Differences. The CfDs in the form of EPADs (Electricity Price Area Differentials) have been implemented in the Nordic electricity market in 2000. Since then, they were under constant scrutiny, since the Regulation (EU) 2016/1719 prescribes transmission rights as the standard basis risk products. Among others, Hagman and Bjørndale (2011) and Spodniak et al. (2017) questioned the superiority of Nordic CfDs in comparison with FTRs.

In the area of transmission rights, physical transmission rights are inherited from the liberalisation of the market in EU. Over the last 30 years, many authors assessed and demonstrated analytically the superiority of financial over physical rights (Batlle López et al 2014), (Joskow and Tirole, 1998) and (Harvey et al., 1996).

Lastly, the financial transmission rights are vastly present across the globe in both zonal and nodal market designs and are considered to be a central piece of the market designs (London Economics International LLC, 2020), (Electricity Authority, 2019). Two central features of FTRs is the revenue adequacy for the TSO and full financial firmness for market participants (Hogan, 2013).

In the current context of the energy transition towards renewable electricity production and the need to ensure security of supply, speeding up the electricity market integration and enhancing the integration of the forward markets is key (ACER, 2022). Having longer-term products is one way to support these objectives (Beato, 2021). However, ensuring the short-term efficiency while maintaining a sufficient liquidity remain a key concern to solve in the continental EU market. A study for the European Commission (2021) concludes that having smaller bidding zones would provide this short-term efficiency and that enhancing the FTR products with a zone-to-zone or zone-to-hub functionality could address the hedging of basis risk. This specific FTR design is supported by Booz & co (2011) and already implemented around the world (PA Knowledge Limited, 2003). Pushing towards a maximal efficiency of system operation, Kunz, et al. (2016) study this concern in a nodal representation of a European network and conclude that FTRs help to mitigate the higher distributional impacts caused by a smaller granularity of network representation in the market design. Many European stakeholders question the potential detrimental impact of a nodal design on the liquidity of the forward markets. Eicke, et al. (2022) conclude that the liquidity of the US forward markets is similar or higher than the one in most European Member States.

1.4 Structure

This policy paper aims to revisit the functioning of the electricity forward market in the EU. It first identifies several shortcomings of the current electricity forward market in the EU. The paper then aims to define the objectives of a well-functioning electricity forward market against which possible improvements will be assessed. The next chapter sets out propositions of policy options for possible improvements and regulatory interventions. This is followed by an assessment of the policy options. The paper ends with conclusions and concrete recommendations for improvements of the EU electricity forward market and of the relevant legislation.

Definitions for acronyms and terms used throughout this paper can be found in Annex I.

2. PROBLEM DESCRIPTION

In the current European internal electricity market, we have identified a number of inefficiencies in the functioning of the electricity forward market. In this paper, we divided those problems into two distinct categories: (i) the problems pertaining to EU electricity forward market in general and (ii) the problems pertaining to cross-border hedging.

2.1 Problems pertaining to EU forward market in general

Problem 1 (market fragmentation): The most important problem that we identify is that the supply and demand for hedging is fragmented into different bidding zones and trading venues. One of the main prerequisites for market liquidity is a sufficient ("a critical mass") supply and demand for specific products meeting at the same trading venue. EU's electricity forward markets in different bidding zones and venues operate largely isolated from each other without much arbitration and integration between them. This affects in particular small bidding zones, which, in such isolation, are not able to attract a critical mass of supply and demand for hedging needed to achieve adequate liquidity. Hence, forward markets in smaller bidding zones suffer from poor liquidity, high bid-ask spread and the problem increases with longer maturities. This problem cannot be solved with just better hedging incentives or better market structure.

Market participants in illiquid bidding zones need to either pay higher premiums for products at illiquid markets or find hedging proxies such as forward markets in neighbouring bidding zones and possibly complement them with transmission rights, if such neighbouring market products do not provide an efficient hedge. In this respect, market participants in small bidding zones face discrimination in market access and a non-level playing field, as they are not in an equal position compared to market participants located in large bidding zones, where liquidity is higher.

Problem 2 (hedging disincentives): Another key problem behind insufficient liquidity is the policy measures in place that removes the natural incentives of market participants to hedge their risk. Examples of such policy measures are subsidies on fossil, renewable and nuclear investments, capacity remuneration mechanisms, retail and wholesale price regulation and any other measures aiming to make investments less risky or giving price comfort to consumers. All these measures protect market participants from risks and thereby take away at least some of their need or incentive to hedge.

Trading at exchanges requires the market participants to provide collaterals. The latter, regulated by European Market Infrastructure Regulation (EMIR), can be considered as a barrier to trade at exchanges for some market participants. The current framework usually does not allow for uncollateralized bank guarantees[1], requiring the market participants to place significant amounts in collaterals which represent a disincentive to hedging at exchanges.

Problem 3 (market structure): Market structure has a significant impact on market liquidity. Three examples of this are high horizontal or vertical integration and significant supply and demand asymmetry. High horizontal integration on supply side reduces competition in forward market as the dominant market players can exercise market power or avoid hedging through organised market places knowing that counterparties cannot hedge without them. High vertical

[1] See ESMA's statement on their exemption regarding the situation on the energy markets : https://www.esma.europa.eu/press-news/esma-news/esma-temporarily-amends-ccp-collateral-requirements-provide-liquidity-relief

integration also creates an uneven level-playing field with competitors, who are not vertically integrated and who perceive hedging as a barrier to entry.

Supply and demand asymmetry does not necessarily imply market concentration, but a lack of physical assets (generation, consumption) in a particular bidding zone. In both cases, one or both sides of the order books for hedging products become poorer and bid ask spreads increase, which has a negative impact on the market liquidity.

Problem 4 (vulnerability to bidding zone reconfiguration): In Continental Europe, each bidding zone is trying to develop its own zonal forward market, whose success, in absence of integration with other zones, largely depends on the size of the underlying bidding zone. Such market design is particularly vulnerable to re-configuration of any bidding zone, since this change may have a detrimental impact on forward market liquidity in such zone. Nevertheless, experience from short-term markets (i.e. single day-ahead and intraday coupling) and from electricity markets in US demonstrate that having large bidding zone is not the only way to achieve market liquidity. Therefore, a forward market design that would make the forward market liquidity less dependent on the size of the bidding zones would be preferred over existing design, where forward market liquidity crucially depend on the size of bidding zones.

2.2 Problems pertaining to cross-border hedging

Problem 5 (LTTRs currently do not facilitate market integration): LTTRs can be used in many different ways. First, they can be used as basis risk products to support proxy hedging, although as indicated in Problem 6 they are currently not very efficient for this purpose. In Continental Europe, proxy hedging with futures in large bidding zone(s) combined with LTTRs to hedge the risk in small bidding zones increase the liquidity of large bidding zone(s) at the expense of liquidity in smaller bidding zones. This proxy hedging therefore aggregates some liquidity in large bidding zone(s), however, there is still important level of trading in small bidding zones, yet very illiquid.

LTTRs are currently not able to combine the liquidity of small zones and large zones into one single integrated market. This is because current LTTRs are not very useful for continuous arbitrage between forward markets[2], since they are not accessible continuously and with the same product timeframes and maturities as futures contracts. Lastly, LTTRs are issued as options which are not suitable for risk-free arbitrage between two futures contracts.

Rather than supporting integration of forward markets, LTTRs seem to be predominantly used for speculation, where market participants accept certain future price risks, but only under the expectation of a profit. This may be one of the reasons for undervaluation as described in Problem 8.

Problem 6 (accessibility of cross-border hedging products): Existing cross-border hedging products (i.e. LTTRs) are not very useful for basis risk hedging. This is because proxy hedging and basis risk hedging requires continuous access to hedging products. However, LTTRs are auctioned only at specific times (i.e. once a year and once a month) and no secondary market exists, where market participants could buy LTTRs at the time when they settle a new trade, which exposes their position. While the single allocation platform allows market participants to transfer the ownership of LTTRs anytime, this feature is very rarely used. Using LTTRs for hedging therefore implies a time risk, i.e. the risk of changing prices when market participants buy LTTRs and the time when they buy/sell futures. Therefore

[2] Risk-free arbitrage of buying Futures in one market, buying LTTRs and selling Futures in another market

LTTRs in the current form are not supporting the continuous nature of forward electricity trading.

Problem 7 (inadequate maturities): Proxy hedging combined with LTTRs is limited only to shorter maturities, namely a year ahead (yearly LTTRs auction about one month before the start of the delivery year) and a month ahead (monthly auction few weeks before the start of the delivery month). This does not enable such hedging to be used for longer-term deliveries or other within-year deliveries (e.g. quarters), which are generally available at liquid forward markets. This puts market participants, which need LTTRs for hedging, in an even worse position compared to participants which can rely on zonal forward market for hedging without the need for LTTRs.

Problem 8 (undervaluation of capacities): LTTRs are continuously being undervalued. All the analyses of ex-post risk premia performed by regulators and TSOs in the past have shown that the prices of LTTRs are, in the long-term average, below the market spread. This has been reported for example in section 6.2.2 of ACER Market Monitoring Report from 2015[3] and in section 4.2 of ENTSO-E's Policy paper on EU's electricity forward markets from December 2022[4]. ACER is aware that LTTR prices represent the expected (forecasted) value of LTTRs, which can almost never be exactly equal to realised value due to inherent errors in forecasting. For these reason ex-post risk premia is estimated as long-term average difference between many LTTRs prices and realised market spreads, which should filter out the uncertain fluctuations of forecast errors. In theory, if LTTRs would be used for hedging purposes, the LTTR prices should on long-term average be above the expected market spread (including also a positive risk premium)[5]. While this effect may at times be very low on some borders, it is often significant on many other borders. Consequently, by issuing LTTRs, TSOs are receiving less congestion income compared to if the long-term capacities would instead be allocated only in the day-ahead timeframe. This loss of congestion income has an impact on the maximisation of cross-zonal capacities, network investments and, in the last instance, on network tariffs.

There may be many reasons for undervaluation, which would deserve a separate investigation. Here we outline few possible reasons:

(i) LTTRs are currently issued as PTR/FTR options whose exact market value is difficult to estimate. Market participants need to forecast prices for each market time unit during delivery period and then take the average of the positive values. This may be quite a challenge for PTR/FTR options with long maturity times and delivery periods. In a similar fashion it is difficult for TSOs and regulatory authorities to estimate the efficiency of pricing of LTTRs for each specific auction – this can only be done ex-post based on long-term average difference between auction price and realised positive market spread.

(ii) PTR/FTR options are currently not well suited for hedging, because they are auctioned only once a year and once a month without any secondary market. In this respect they can hardly complement proxy hedging, which would require

[3] https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202015%20-%20ELECTRICITY.pdf

[4] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Network%20codes%20documents/NC%20FCA/publications/ENTSO-E_Policy_Paper_forward_markets_Final.pdf

[5] A negative risk premium could occur only in case where the seller of the contract is more interested to hedge than the buyer. But in case of LTTRs, TSOs are not active price setters and have no interest to hedge themselves.

continuous access to LTTRs. They are also not well suited for arbitraging between two forward markets (i.e. buying/selling futures in one bidding zone buying PTRs or FTRs and selling/buying futures in another bidding zone). This may result in an outcome where most of the demand for LTTRs come from speculators, which expect a profit from LTTRs (i.e. negative risk premium).

(iii) Lack of competition. LTTRs are currently still issued separately per each bidding zone border without any competition between borders. This is expected to improve with the introduction of the flow-based approach. The existence of any entry barriers should also be investigated.

(iv) PTR/FTR options still do not have full financial firmness as there are still a few exceptions discussed in section 5.3.4, which reduce the firmness of PTR/FTR options.

Problem 9 (non-coordinated assessments and decisions): The criteria for NRAs to evaluate the sufficiency of hedging possibilities and subsequently decide whether TSOs are allowed to provide equivalent measures to LTTRs or not provide any support at all, is neither clear nor harmonised. This makes the application of this flexibility provided by the EU legislation confusing and often lacking proper justification. Consequently, TSOs may auction LTTRs on bidding zone borders even where there is no absolute necessity (e.g. between Germany and France where liquid forward markets exist on both sides of the border) or they abstain from being involved even in cases where such need exists.

Another problem identified by some regulatory authorities is the efficiency of capacity allocation in flow-based approach, which favours large bidding zones and bidding zones at the perimeter of regions (the problem known as flow factor competition). While this problem may worsen the accessibility of LTTRs in small bidding zones in the flow-based approach, it is not specifically addressed here, as it is not unique to long-term capacity allocation and may need to be addressed by other more structural measures.

3. OBJECTIVES

In this paper, we assume that the key goal of the electricity forward market is to enable market participants to hedge the risk of their uncertain future cash flows (arising from electricity production, consumption and trading) in timeframes far ahead of delivery.

This overarching goal, combined with the objectives of the framework guidelines listed in Regulation (EU) 2019/943 ('Electricity Regulation') Article 59(4), allow us to derive a set of objectives against which the different policy options to address the problems will be assessed.

Objective 1 (effectiveness to enhance market integration)

A fully integrated internal electricity market is of utmost importance to secure affordable prices to EU citizens, security of supply and to transition towards an environmentally sustainable electricity sector. Any policy change should strive to make electricity markets in Europe work as one by removing barriers to trade and establishing harmonised market rules. Furthermore, policy changes should contribute to the long-term evolution and development of the internal electricity market in the Union. In the context of electricity forward market, the market integration should strive to achieve a single EU electricity forward market with frequent/continuous matching of supply and demand across EU supported by the available cross-zonal capacities.

Objective 2 (effectiveness to ensure non-discrimination)

The EU electricity forward market should ensure equal treatment of all involved parties. Therefore, any policy option should set out a non-discriminatory treatment of market participants, independently from their location or their needs, but also for the non-discriminatory treatment of TSOs and other stakeholders. In the context of electricity forward market, this objective implies that all market participants have equal access to long-term hedging opportunities.

Objective 3 (effectiveness to increase competition)

Competition is crucial for the proper functioning of the EU internal electricity market. Policy changes should aim at reducing any barriers for trade and competition between market participants within and between Member States at wholesale as well as retail level. This should result in higher liquidity and greater competition and should, therefore, lead to more competitive hedging products (low bid-ask spread, low risk premium). Competition should increase both for forward market products (futures, options) as well as for LTTRs.

Objective 4 (effectiveness to enhance the efficient functioning of the market)

An efficiently functioning electricity forward market needs to allow market participants to hedge their exposure both in an effective and efficient way. The hedging products must allow to effectively hedge the risks of the market participants and should be accessible in a way which is efficient for the market participants. Policy changes should therefore contribute in enhancing the efficient functioning of the forward market.

Objective 5 (efficiency)

Policy changes need to balance the expected benefits they bring compared to their costs or the amount of resources needed for their implementation and operation.

Objective 6 (coherency)

Policy changes need to maintain a sufficient level of coherency with other policies, and therefore with the design of other electricity market segments, as well as with the other overarching objectives of the EU policy.

4. GENERAL POLICY OPTIONS BEYOND FCA REGULATION

Considering the problems identified in Chapter 2, this chapter introduces general policy options that go outside the scope of the Forward Capacity Allocation Regulation ('FCA Regulation') and, for some, outside the competence of energy regulators. As such, those options are not assessed within this document and are to be understood as general policy options to be considered by the relevant authorities.

4.1 Improving market structure, promoting competition

One of the fundamental reasons for insufficient forward market liquidity reported by respondents to the public consultation is the market structure, which does not provide sufficient conditions for proper competition. As indicated in Problem 3 of chapter 2.1 above, the two main reasons are high market concentration in some bidding zones (namely on the supply side) and supply/demand asymmetry. These two problems can only be addressed by measures enhancing competition between existing market participants or measures to attract new entry in bidding zones lacking more competition on supply or demand side. Therefore, to improve market structure, ACER emphasises the need to continue investigating cases of high market concentration and improving competition as well as removing entry barriers for new entrants as much as possible. Nevertheless, ACER also emphasises that relying on effective competition in each isolated national market is a false hope and cross-border competition is by far most effective measure to increase competition in electricity market and may significantly reduce any shortcomings in national electricity markets.

4.2 Reduce hedging disincentives

In Problem 2, we describe several regulatory interventions which have the effect to reduce the need or incentive to hedge. Such interventions are subsidies on fossil, renewable and nuclear investments, capacity remuneration mechanisms, retail and wholesale price regulation and any other measures aiming to make investments less risky (e.g. reliability options, flexibility options, CfDs, cap & floor, etc.). These measures therefore protect producers against investment risk and consumers against high prices. ACER understands that there may be some underlying reasons for these measures, e.g. mitigate high investment risk, ensure adequate revenue for generators or protect consumers against high prices.

If regulatory intervention are needed to mitigate high investment risk, these should not take away all the risk the investor faces, but rather only the extreme risk (e.g. for generators the risk of extremely low prices). This would ensure that investors are still incentivised to hedge the bulk of the price risk, since regulatory interventions are removing only the risk of extreme price outcomes. The same principle applies to capacity remuneration mechanisms, which, if designed properly, should only protect against the uncertainty of price spikes in period of shortages and the consequent uncertainty on the recovery of the investment costs.

Regarding the protection of consumers against high prices, ACER recommends that such protection should primarily come from the interest and preferences of consumers and not by default from regulatory interventions. Consumers should be exposed to price risks and therefore be incentivised to hedge their procurement costs as well as reveal their flexibility (demand response), which is an essential element of future decarbonised electricity market. Default regulatory interventions, if needed, should again only protect consumers against prolonged extreme price scenarios. This would provide some protection for consumers in case of extremely high prices, but not remove their need for hedging as well for revealing flexibility based on their individual preferences.

ACER therefore recommends policy makers to design regulatory interventions in a targeted way, which minimises the impact on hedging incentives.

4.3 Re-configuration of bidding zones

Stakeholders have proposed to increase the size of bidding zones in order to improve the liquidity of forward markets inside such bidding zones. However, enlarging bidding zones disregarding network congestions may have negative consequences on other aspects of market functioning such as redispatching costs, price signals, flexibility and the volume of cross-zonal capacities and hence cross-border competition. This is addressed with a specific process called the bidding zone review, which aims at assessing all the aspects above mentioned in a single integrated process. This process can lead to the merger of small bidding zones if such a merger would have a positive impact on market functioning.

4.4 Reduce barriers to trade at organised marketplaces

Organised market places offer market participants more standardised hedging products with fully covered counterparty risk. This is not the case on OTC or bilateral markets where the counterparty risk is usually not fully covered. On the other hand, hedging at organised market places comes at a higher costs mainly membership costs, trading costs as well as costs of collaterals. In recent period of high and volatile electricity prices the collateral requirements have been increased significantly to the extent that many market participants are no longer able to meet these requirements. This decreases the possibility and incentive to trade and hedge via organised market places.

While ACER acknowledges this problem is significant and needs to be addressed, it also emphasizes that energy regulators do not have competence in this area. ACER therefore joins the European Commission's call to relevant financial authorities to explore possible solutions to reduce the barriers to trade at organised marketplaces.

5. POLICY OPTIONS PERTAINING TO THE FCA REGULATION

This chapter, focuses on recommendations within the scope of energy regulators and FCA Regulation. It focuses on three categories of problems, namely (i) is the regulatory intervention needed? (ii) what kind of regulatory intervention is most suitable? and (iii) if TSOs issue transmission rights, what should be the form of these transmission rights?

5.1 The need for intervention

5.1.1 Option 1.0: Status quo: Regionally different approaches

The current FCA Regulation and Regulation EU 2019/943 provide a framework for TSOs to issue LTTRs or to apply equivalent measures that enable to hedge price risks across bidding zone borders, except in cases where regulatory authorities identify that the forward market provides sufficient hedging opportunities in the concerned bidding zones.

This framework resulted in three different regimes across Europe:

- LTTRs in the form of PTR/FTR options are issued in capacity calculation regions of Core, Italy North, South East Europe and South-West Europe regions as well as on bidding zone borders FI-EE, EE-LV, DK1-DE, DK1-NL, DK2-DE and DK1-DK2. These LTTRs are issued within the framework of the Single Allocation Platform and Harmonised Allocation Rules as established by the FCA Regulation.
- In the Nordic CCR, TSOs currently issue LTTRs only on DK1-DK2 border. On the remaining borders, regulatory authorities decided that forwards and futures linked to the Nordic system price forward market as well as CfDs are sufficient to provide hedging possibilities to market participants active in the Nordic bidding zones.[6]
- In bidding zones within Italy, the TSO allocates the so-called Contracts Covering the Risk of Volatility of the Fee for Assignment of Rights of Use of Transmission Capacity ('CCCs') which are a form of FTR obligations linked to a hub price (which is the Italian

[6] Recently some Nordic regulatory authorities are discovering that some bidding zones may not provide sufficient hedging opportunities. For example, in March 2022 the Finnish regulatory authority informed ACER that it has identified insufficient hedging opportunities in the Finnish bidding zone. The case between Finland and Sweden was referred to ACER in March 2022 and ACER decided in September 2022 to request the Finnish and the Swedish TSOs not to issue LTTRs but instead to ensure the availability of other long-term cross-zonal hedging products.

PUN price) and the volume of allocated CCCs from different bidding zones is limited with long-term transmission capacity between bidding zones.

The regionally specific regimes mainly results from the historical development on how regional markets have been setup before the integration into the EU market. In particular, the different approach to bidding zones (i.e. the Nordic and Italian market favouring small bidding zones to manage congestions more efficiently) is a major contributor to a different forward market design.

Benefits of this option

The benefit of this option is that it allows flexibility for national regulatory authorities to tailor the hedging market according to their views and assessment of the specific market needs.

Drawbacks of this option

The drawback is that these assessments are not harmonised, transparent and may lead to different decisions ending up in different regimes, which may not necessarily be justified by the differences in market fundamentals.

5.1.2 Option 1.1: Coordinated assessment and decisions on TSOs' obligations

This option follows the legal framework established in Article 9(1) of Electricity Regulation. This Article requires TSOs to issue LTTRs or have equivalent measures in place to allow market participants to hedge price risks across bidding zone borders. Exceptionally, regulatory authorities may exempt TSOs from this obligation subject to an assessment performed by the competent regulatory authorities showing that there are sufficient hedging opportunities in the concerned bidding zones.

This option aims to clarify the procedure and governance of requirements in Article 9(1) of Electricity Regulation. In this option we propose that both decisions, i.e. (i) on equivalent measures and (ii) on the exemption of TSOs, are made in a coordinated way by regulatory authorities at least at regional level. In particular, the assessment on exemption should use transparent and precise metrics to measure the functioning of the forward markets and possible inefficiencies that would occur in the absence of measures introduced by TSOs. The assessment can be done by regulatory authorities of a CCR at their own initiative or at the request of TSOs or market participants. The outcome of the assessment should be consulted with market participants to make sure that the equivalent measures or exemption of TSOs are taking into account the market needs and local conditions.

After the assessment is finalised, regulatory authorities may make a decision on the equivalent measures or exemption of TSOs. Such a decision should be done in a coordinated way in each CCR for all bidding zones or bidding zone borders of a CCR. This coordinated decision does not exclude the possibility of different measures at different bidding zones or borders if all regulatory authorities of a CCR agree.

Benefits of this option

The standardized regulatory intervention (i.e. LTTRs) would be applied in all areas, unless regulatory authorities approve equivalent measures or exemption to the TSOs' obligations. Therefore, the overall administrative effort and costs for regulatory authorities would be decreased to a minimum level as these decisions are optional and made on an "if-need" basis. The assessments and decisions would become more transparent, comparable and efficient than national ones. For TSOs, thanks to an increased standardization, the administrative burden would also be reduced.

Drawbacks of this option

This approach reduces the national flexibility in the assessments and decisions because they need to be coordinated and agreed at regional level. Market specificities such as the share of consumers on fixed price contracts, hedging possibilities outside organised markets and size and price correlation between bidding zones make it difficult both to calculate comparable parameters and to decide on the appropriate common thresholds.

5.1.3 Option 1.2: Mandatory intervention

This option assumes regulatory intervention (i.e. LTTRs or equivalent measures) by default in all regions. It means that regulatory authorities cannot exempt TSOs from their obligations and therefore regional or national assessment and decisions of regulatory authorities are not needed. It therefore assumes that besides the non-regulated forward market, TSOs would always be involved by issuing LTTRs or having equivalent measures in place.

The benefit of this option is that regulatory authorities would not need to perform assessment of sufficient hedging opportunities and deciding on exemptions for TSOs. The drawback is the risk that the intervention would be in place even when there is no need. In such cases it could be argued that this brings unnecessary costs and burden and could perhaps also damage the forward market.

5.1.4 Option 1.3: No regulatory intervention

This option does not pursue any TSO or regulatory involvement in supporting the forward market. It is based on the trust that the market would provide sufficient hedging opportunities reflecting the supply and demand for hedging. This option assumes that if there is demand for hedging there will surely be a supply for it and liquidity will develop.

The conditions of well-functioning forward market could be achieved in a market model similar like any forward market where financial derivatives are standardized and traded in an exchange or over the counter. In this case, the demand for hedging is the driving force which will attract sufficient supply to cover the demand. The price of these products will therefore reflect the demand and supply of hedging. If the market works efficiently, the bid/ask spread of the hedging product is expected to converge to zero, reflecting zero transaction costs and, therefore, efficient hedging. Any temporal lack of supply will increase the bid/ask spread and this is expected to gradually attract additional supply.

Even if this option assumes no regulatory intervention, it still allows power exchanges to facilitate the liquidity with market makers. This possibility exists in all options and is independent of the discussion about regulatory interventions in this section. Such market making would be outside regulatory control and without any regulated cost recovery. It is left completely to the discretion of each power exchange. See section 5.2.7 for more description of the market making function.

Benefits of this option

The main benefit of this approach is that market participants are able to meet their hedging requirements in a cost-efficient way, provided that the pre-conditions of a well-functioning forward market are in place. It also implies no costs for regulatory authorities, TSOs and end consumers from supporting the forward market.

Drawbacks of this option

In practice, effective competition is limited to markets with high liquidity with enough supply and demand of financial derivatives. In the absence of effective competition, cost-efficient hedging as described above would not be possible.

Another challenge that prevents well-functioning forward markets are exchange requirements and costs, especially for small market participants. In this case, OTC trading is an alternative for market participants. However, the available information to market participants is not as transparent as at the exchange.

In addition, also the predictability of future prices and the volatility of the market are reflected in the risk premium and the bid/ask spread. Consequently, well-functioning forward markets are more difficult to achieve in periods with high volatility. However, this uncertainty remains also when TSOs are obliged to intervene by auctioning LTTRs or other hedging products.

5.2 Type of intervention

5.2.1 Option 2.0: Status quo: Bidding zone border LTTRs

The current FCA Regulation provides a framework in which long-term cross-zonal capacities are allocated with **explicit allocation** and LTTRs are issued to market participants based on such allocation. These are issued on bidding zone borders ('BZB') only, which means only between neighbouring bidding zones which are interconnected. This setup results from historical development where cross-border trading began between neighbouring bidding zones only based on available interconnection capacity. Only after the markets have been properly integrated and especially with the introduction of flow-based capacity calculation, it became apparent that the option to allocate LTTRs also between non-neighbouring bidding zones is also feasible, but is not yet integrated in the legal framework.

For a concrete example on the functioning of this option see Case 1 in Annex III.

5.2.2 Option 2.1: Improved access

This option is applicable to cases where TSOs allocate long-term cross-zonal capacities and assumes a change in the cross-zonal capacity calculation towards a statistical approach, in longer horizons (up to 3YA), with more frequent allocations and potentially up to a continuous access (for leftovers only) in order to facilitate secondary market.

5.2.2.1 *Adequate cross-zonal capacities*

Allocating cross-zonal capacities in longer horizons raises concerns on uncertainties in capacity calculation and how much cross-zonal capacity can be offered within such a long horizon. The Electricity Regulation requires that 70% of the maximum capacity of network elements should be made available for the capacity calculation pursuant to the CACM Regulation. However, there is no such requirement for the FCA Regulation yet. Nevertheless, using the historically offered day-ahead cross-zonal capacities as a basis, we propose to apply a statistical approach to long-term capacity calculation with the objective to maximise long-term cross-zonal capacities (when needed), yet still minimise the risk that long-term cross-zonal capacities would be higher than day-ahead cross-zonal capacities (which would expose TSOs to the risk of revenue inadequacy). A proper balance between these two conflicting objectives needs to be found.

Nevertheless, to minimise the possible risk of undervaluation, we also propose a process to adjust (reduce) the capacity made available in the forward timeframe in case of structural undervaluation, which cannot be solved with other available means. This process could include the following elements:

(i) TSOs regularly monitor of ex-post risk premia based on sufficient history or actual risk premia (in case of FTR obligations, their prices could be benchmarked to baseload prices);
(ii) in case structural undervaluation is identified, TSOs can propose amendment of capacity calculation methodology proposing reduction of offered capacities; and
(iii) regulatory approval of the amended capacity calculation methodology.

5.2.2.2 *Longer maturities*

This option takes into account that LTTRs are usually complementary hedging products in the sense that they are combined with forwards and futures traded at financial electricity markets. However, market participants complain that while they are able to trade forwards and futures for several years in advance, they are not able to complement them with LTTRs because they are offered only one year ahead or one month ahead and just shortly before delivery starts. Such LTTRs therefore fail to support trading and hedging in longer-term horizons.

To address this problem, the products issued by TSOs with capacity allocation could extend its time-to-delivery to meet the market needs. As described in the section 1.2 describing the scope of the paper, the three-year ahead (3YA) timeframe is often considered as the horizon in which the consumers are strongly interested to hedge, whereas beyond this horizon, the interest decreases significantly.

A longer horizon would also imply that cross-zonal capacities would have to be allocated more gradually with smaller quantity for each auction and increasing the total amount closer to the delivery.

This longer horizon may also require some changes in the rules for settlement and requirements for collaterals. Today, SAP settles long-term auctions income in monthly instalments and remunerates LTTR holders daily at delivery. However, the SAP could apply daily settlement only, where only the difference between the original auction price and day-ahead market spread would be settled at delivery. This could potentially reduce the level of required collaterals.

5.2.2.3 *More frequent auctions*

This option aims to improve the problem noted by market participants that they enter into long-term contracts on a continuous basis, but they are only able to acquire LTTRs in very few occasions. Furthermore, the secondary market for LTTRs has never developed and therefore it is not possible for market participants to use LTTRs for efficient proxy hedging on a continuous basis.

One elements to improve this discrepancy could be to introduce more frequent auctions. Auctions could be organised on a weekly basis (e.g. each Wednesday) for all products up to 3YA (i.e. months, quarters, years). These auctions would of course offer the possibility to resell previously allocated LTTRs. Even better option would be to organise an auction each working day, however in this case new capacity could not be provided to each auction. In such case the auctions each Wednesday could provide new cross-zonal capacities, whereas auctions on Monday, Tuesday, Thursday and Friday would offer only the capacity leftovers.

This option would on one hand imply less demand for cross-zonal capacities compared to today due to more frequent auctions, but on the other hand also less supply of new cross-zonal capacities at each auction. This option would also increase administrative burden of auctioning and thereby increase the costs of SAP.

5.2.2.4 *Secondary market through continuous access*

The secondary market is understood as continuous access for LTTRs (or CfDs) during working hours of working days between two consecutive auctions. In case of LTTRs, this secondary market could be organised as today where SAP only allows the transfer of LTTRs to another holder, but does not organise a platform for secondary trading. On the other hand, secondary market could also be organised by SAP by providing a platform for continuous trading of LTTRs combined with the allocation of leftover cross-zonal capacities. In case of CfDs, secondary market would be organised by power exchanges in form of continuous-based market coupling with leftover capacities. In case LTTR auctions are performed once each day, the need for secondary trading may be questioned, and would depend on the interest of market participants.

Continuous access implies the allocation of leftover capacities without capacity pricing. Such a solution is feasible in case the timing between two consecutive auctions is rather short as this ensures that market fundamentals have not changed significantly and that the leftover capacities still have a zero or very low value. However in case auctions are organised only once a week, the market fundamentals can significantly change during the period between two auctions and the certainty that leftover cross-zonal capacities still have a zero value diminishes significantly. Therefore, ACER considers that continuous access with allocation of cross-zonal capacity is feasible only in case of more frequent (i.e. daily) auctions.

An example on the organisation of the auctions could be the following:

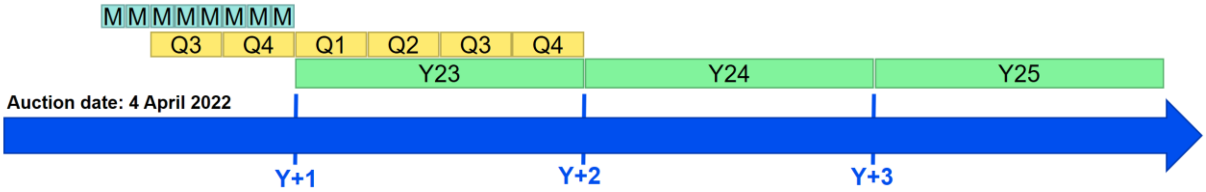

Figure 1: Example of allocation timeframes

5.2.3 <u>Option 2.2: Zone-to-zone LTTRs</u>

This option assumes improvements of the current border-wise LTTRs and expand them to any-zone to any-zone (‘Z2Z’) LTTR, which entails that bidding is also allowed Z2Z. This option is specifically suitable for flow-based capacity allocation, but also possible when coordinated net transmission capacity approach is used. Long-term cross-zonal capacities are allocated with explicit allocation.

Cross-regional hedging could also be added to this option. This would mean organising cross-regional auctions covering the geographical scope of all CCRs issuing LTTRs. The benefits of those auctions lie in the efficiency in bidding for the market participants compared to a regional approach.

For a concrete example on the functioning of this option see Case 2 in Annex III.

Benefits of this option

This option allows more efficient hedging between non-neighbouring bidding zones compared to Option 2.0, where hedging between non-neighbouring bidding zones with BZB LTTRs is very inefficient and complex as it involves purchasing multiple products in auctions organised at different moments in time.

Drawbacks of this option

While this option does improve hedging possibilities compared to Option 2.0, it is unlikely to solve (actually it could even exacerbate) the problem of illiquid secondary market for LTTRs because the number of different LTTRs would explode. Without liquid secondary market, this option is unable to facilities integration of forward markets as explained in Problem 5.

5.2.4 Option 2.3: Zone-to-hub LTTRs

The motivation for this option is to aggregate forward market liquidity at a single hub instead of at each bidding zone separately (similarly to the model currently implemented in Italy or in the Nordic CCR). Zone-to-hub (Z2H) LTTRs would then provide a hedging instrument to cover the risk of remaining price difference between the hub and zonal price (basis risk). Thus, several small bidding zones could aggregate their supply and demand for hedging in a common hub where liquidity can more likely develop than in each zone separately, whereas big bidding zones which already have liquid national zonal forward market could continue using this national market or shift the trading to the hub as well. It is assumed that such hubs will attract demand for futures and forwards linked to these hubs (because all FTRs would be linked to these hubs) and that power exchange will offer trading with such futures and forwards without the need for regulatory intervention.

This option therefore assumes improvements of the current BZB LTTRs and expand them to Z2H LTTRs, whereas bidding can be both Z2Z and Z2H. It therefore allows market participants not only to hedge against price differentials between two bidding zones, but also to hedge the price of a bidding zone against the price of a hub.

Market participants could submit Z2H orders or Z2Z orders and the auction algorithm would match the orders in a way that maximises the economic surplus[7], whereas the volume of accepted orders multiplied by the corresponding Z2H power transfer distribution factors (PTDFs) would be equal or lower than the remaining available margin on all critical network elements. With this respect, the location of the physical hub against which the PTDFs are calculated is not important as long as the net position of the hub is zero.[8]

In case a market participant would want to hedge zone-to-zone as in Option 2.2, it would submit such a Z2Z order. If the order is accepted, such a market participant would receive two Z2H products, namely one Z2H and one H2Z (which can later be resold separately).[9]

$$LTTR_{Zone\ A\ to\ Zone\ B} = LTTR_{Zone\ A\ to\ Hub} - LTTR\ _{Zone\ B\ to\ Hub}$$

This option assumes the establishment of price hubs aggregating the day-ahead prices of several bidding zones. The price formation of such hubs could be either based on dynamic factors fixed “ex-post” (e.g. volumes traded at the day-ahead market) or factors fixed “ex-ante”, prior to the issuance of the LTTRs (e.g. forecasted yearly electricity consumption of the bidding

[7] Sum of products of order prices and their accepted volume.

[8] Depending on the hub price formation (ex-ante vs ex-post defined parameters), an FTR Z2H order might need or not to be complemented with another order, from the same or another bidding zone.

[9] A negative sign should be interpreted as a “sell” order. In an example where the $LTTR_{Zone\ A\ to\ Hub}$ would be purchased at 5€/MW and the $LTTR\ _{Zone\ B\ to\ Hub}$ would be sold at -1€/MW, the total value of the $LTTR_{Zone\ A\ to\ Zone\ B}$ is equivalent to 6€/MW.

zones composing the hub).[10] In case the weights (determining how the price of each zone is represented in the hub price) are fixed ex-ante, such hub could accommodate allocation of FTR obligations and options, whereas in case the weights are known only ex-post, only FTR obligations would be possible. The exact definition of the hub requires careful analysis, and stakeholder consultation as well as regulatory approval would be needed before defining such a hub.

In this option, each CCR would therefore have the possibility to either create its own hub or issue Z2H LTTRs to a hub in another CCR. This decision would be guided by the interest and motivation to provide market participants sufficient and liquid hedging opportunities at a hub complemented by sufficient Z2H LTTRs to each zone. The Z2H LTTRs would therefore provide a hedge to cover the remaining risk between the hub price and the price of each individual bidding zone. Bidding zones part of multiple CCR hubs would have the possibility to issue LTTRs towards one or multiple hubs.

In this option, the SAP would be the counterparty for LTTRs holders. The LTTRs could be resold at the next auction or on the secondary market. At delivery, the SAP would settle with each LTTR holder the difference between the original LTTR price (the price at which the LTTR was obtained) and the day ahead price differential between the corresponding zonal price and hub price. In principle, TSOs would receive the congestion income resulting from the allocation of long-term cross-zonal capacities through such LTTR auction and at delivery pay back to LTTR holders the congestion income received from reallocation of these capacities in the day-ahead coupling. In practice, both financial streams would be netted and settled at delivery.

If this option provides adequate hedging to each bidding zones within a region, then cross-regional hedging possibility is automatic, i.e. by locking electricity price in two zones belonging to two different regions, for example by purchasing and selling futures in two corresponding hubs and LTTRs towards two corresponding zones.

For a concrete example on the functioning of this option see Case 3 in Annex III.

Benefits of this option

This option allows and facilitates the emergence of forward trading hubs aggregating supply and demand for hedging from more than one bidding zone, which should improve the forward market liquidity, compared to a situation where each biding zone would rely on its own zonal forward market. This option also allows for a dual type of hedging, namely Z2Z and Z2H, thereby adding new options, while not removing any existing ones.

This option is very flexible to any changes in bidding zones – namely the change of biding zones would have a minor impact on the hub price and the products traded at the hub price would be largely unaffected by such a change. For example, changes of bidding zones in the Nordic electricity market are fairly simple and can be implemented fast due to such a design. The change of bidding zones would only affect the LTTRs in the bidding zones which are directly concerned and thereby the impact is limited to these areas and to the basis risk only.

Furthermore, in this option there is a single LTTR product per bidding zone (even successful Z2Z orders result in two separate Z2H LTTRs) – this means less products and more likely development of secondary market for them. Furthermore, in case Z2H LTTRs are FTR obligations, they would be financially equivalent to CfDs (and futures contracts, either zonal

[10] In the current application of a hub model, the hub price is computed as the average volume-weighted day-ahead price of each bidding zone in Italy and as the unconstrained (i.e. without any cross-border congestion) day-ahead price in the Nordic CCR.

or linked to the hub), which may be traded in parallel on the power exchanges or OTC. Z2H LTTR holder can sell an equivalent product in the form of a CfD without incurring any additional financial risk. Thereby such LTTRs can facilitate more liquidity in the CfD markets (like the Nordic EPAD market).

Another benefit of this option is that it allows for a unified market model across the whole EU (as Nordic electricity market already has a hub-based system which could easily be complemented with Z2H FTRs) and it is suitable for possible future changes towards very small bidding zones (e.g. offshore bidding zones) or nodal market. In such cases, these small zones or nodes would hedge with hub-based futures combined with LTTRs issued by TSOs.

Drawbacks of this option

The drawback of this option is that it is to a large degree conditional on the liquidity of the hub-based forward market to which the LTTRs are linked. This would mean forward market trading in small bidding zones would need to largely shift to the regional hub. There is no real reason to believe this would not be successful, however, if such forward market for the hub does not develop, one could question the added value of this design. Nevertheless, this option would still facilitate Z2Z hedging and the secondary market. Namely, Z2Z combos can always be split and new Z2Z combos can be formed by procuring two Z2H and H2Z LTTRs in the secondary market. Therefore the risk of failure to achieve the liquid forward market at the hub should not be a determining factor in establishing such a model.

5.2.5 Option 2.4: Forward market coupling with CfDs

This option entails defining standard products in a form of CfD contracts linked to predefined hub prices and then cross-zonal coupling with these. These CfDs are financially equivalent to Z2H FTR-obligations in Option 2.3 in the sense that they offer the same hedge between zonal day-ahead price and day-ahead hub price. The only difference to Z2H FTRs is that the counterparty in these contracts would be power exchanges (NEMOs) instead of SAP. Such contracts (although not supported by the allocation of cross-zonal capacities) exist today in the Nordic market, known as EPADs, although there is currently no cross-zonal matching and coupling of such EPADs in the Nordic market. All principles related to hub-based forward market in Option 2.3 also apply to this option, except that basis risk would be hedged with CfDs instead of FTRs.

This option intends to replicate the market coupling model from the day-ahead and intraday timeframe. This entails the following elements:

- the competent authorities designate one or more nominated electricity market operators for forward timeframe in each bidding zone;
- a harmonised set of CfDs which are used in the market coupling (e.g. yearly, quarterly and monthly CfDs);
- the forward market coupling algorithm that matches CfD orders from each NEMO and each bidding zone while taking into account the long-term cross-zonal capacities provided by TSOs; and
- the clearing and settlement among NEMOs and TSOs.

Similar to Option 2.3, this option assumes the establishment of price hubs aggregating the day-ahead prices of several bidding zones. It is assumed that such hubs will attract demand for futures and forwards linked to these hubs and that power exchange will offer trading with such hubs without the need for regulatory intervention. The regulatory intervention would only be applied to facilitate CfD trading and these CfDs would provide a hedge to cover the remaining risk between the hub price and the price of each individual bidding zone.

In this option, NEMOs would collect orders for CfDs from market participants and send them to the Market Coupling Operator (‘MCO’). Similarly, TSOs would send long-term cross-zonal capacities to MCO. The MCO would then match all orders from all NEMOs and the cross-zonal matching would need to respect the cross-zonal capacities provided by TSOs. After the orders are matched, the results are provided to NEMOs and TSOs. The market coupling could accommodate similar auction timeframes as in Option 2.1 as well as continuous trading between them. The orders and contracts would need to be directly transferable between auctions and continuous trade such that the contract obtained in the auction can be resold at continuous trade and vice versa.

At delivery, each NEMO will settle with each CfD holder the difference between the original CfD price (the price at which the CfD was matched) and the day ahead price differential between the corresponding zonal price and hub price. In principle, TSOs would receive from NEMOs the congestion income resulting from the allocation of long-term cross-zonal capacities through such forward coupling and at delivery pay back to NEMOs the congestion income received from reallocation of these capacity in day-ahead coupling. In practice, both financial streams would be netted and settled at delivery.

The governance of this option could be similar as for the day-ahead and intraday coupling where Member States or their designated authorities designate or grant a passport to NEMOs for the purpose of forward market coupling. Although these NEMOs would perform competitive tasks, regulatory authorities would need to monitor these NEMOs in their execution of their tasks (i.e. collecting orders, settlement, etc.). In parallel, the monopoly tasks of market coupling operation could be performed by a central entity (which could be a new role for SAP). The oversight of this entity would need to involve all NRAs and/or ACER.

For a concrete example on the functioning of this option see Case 6 in Annex III.

Benefits of this option

The benefit of this option, compared to Option 2.3, is that it allocates cross-zonal capacities without establishing separate markets for FTRs and CfDs. Therefore, CfDs obtained at the auction can be immediately resold in continuous trading (or vice versa) and thus effectively fully close the position[11]. This enables a single market for CfDs, whereas in case of Z2H FTRs, the two markets must remain strictly separated, and only arbitrage between two markets are possible. Market participants would thus be able to obtain all hedging products at a single point, (e.g. single NEMO), which reduces the costs of trading (fees, collaterals).

This option, similar to Option 2.3 is very flexible to any changes in bidding zones – namely the change of biding zones would have a minor impact on the hub price and the products traded at the hub price would be largely unaffected by such change. For example, changes of bidding zones in the Nordic electricity market are fairly simple and can be implemented fast due to such a design. The change of a bidding zone would only affect the CfDs in the bidding zones which are directly concerned and thereby the impact is contained only to such area and only to the basis risk.

Like in Option 2.3, a specific challenge is the hedging on the interfaces between regional hubs. Namely, bidding zones which are located in two or more regions would be linked to two or more hubs. One solution would be to enable two or more CfDs for such hubs, while the other solution would be to limit such bidding zones only to one hub, in which case some cross-zonal

[11] This is not the case in FTRs, which, when resold as CfDs, would not close the position as these are open towards different central counterparty (FTRs towards JAO and CfD towards PX).

capacities on the interfaces would not be allocated (for example if FR bidding zone would offer only CfDs linked to Core hub) the long-term cross-zonal capacity linked to SWE hub would not be allocated.

Another benefit of this option is that it allows for a unified market model across the whole EU (as Nordic electricity market already has a hub-based system with CfDs) and it is suitable for possible future changes towards very small bidding zones (e.g. offshore bidding zones) or nodal market. In such cases these small zones or nodes would hedge with hub-based futures combined with CfDs facilitated by forward market coupling.

Drawbacks of this option

This option implicitly requires the development of a liquid forward market at the hub to which the CfDs are linked. It therefore assumes that forward market trading in small bidding zones would largely shift to hub-based forward market trading. If such forward market does not develop, these CfDs would be used only for Z2Z hedging.

This option requires a rather complex setup of market coupling, NEMO designation and cross-border clearing and settlement as well as monitoring tasks which would cause an additional administrative burden. While experience, algorithms and entities from day-ahead and intraday coupling would simplify implementation and operation, it is arguably a more burdensome and complex option than Option 2.3. Compared to Option 2.5, this option requires the establishment of new CfD products (except in Nordic and Baltic region and inside Italy where these already exist).

5.2.6 Option 2.5: Forward market coupling with futures

This option is similar to Option 2.4, except that the coupling is not organised with standard CfDs, but instead with standard futures contracts, which are currently traded at different forward power exchanges. This option does not need a hub and allows the existing forward markets and futures products traded therein to be coupled with long-term cross-zonal capacities. Similarly as in Option 2.4, at the delivery of these forward contracts, the TSOs would cover or receive any net financial income from settlement of such standard futures.

This option therefore aims to provide more liquidity to existing national forward markets by providing a platform where these standard futures products could be automatically traded across the border by taking into account the available long-term cross-zonal capacities. The market coupling could be organised with auctions and continuous trading as in Option 2.4.

For a concrete example on the functioning of this option see Case 7 in Annex III.

Benefits of this option

The benefit of this option is that it would support existing forward markets by providing additional liquidity due to cross-border matching. It therefore does not require any change in the design of existing forward markets, only standardisation of few futures contracts (e.g. yearly, quarterly and monthly baseload futures). Similarly to Option 2.4, market participants would be able to obtain all hedging products at a single point, (e.g. single NEMO), which reduces the costs of trading (fees, collaterals). This option is the only one which does not require specific cross-zonal products (i.e. LTTRs or CfDs) which significantly reduces market fragmentation.

Drawbacks of this option

The drawback of this option is that it is less flexible to any bidding zone reconfiguration – namely the change of biding zones would still have a significant impact on the forward market

as the underlying price would significantly change. Nevertheless, it would still prevent significant loss of liquidity since any loss of liquidity due to reduction of bidding zone size would be compensated by liquidity resulting from cross-zonal matching.
Another drawback of this option is that it is unlikely to be suitable for areas, which already have hub-based forward markets with CfDs. This would mean that the forward market design would remain different in different regions.
Finally, this option is not well suited for future changes in EU electricity market which may at least in some cases converge towards smaller bidding zones (e.g. offshore bidding zones) or nodal market. In such cases, developing forward markets for each small zone or node would not make much sense even in the presence of forward market coupling. In this option, the market participants exposed to prices in small zones would very likely still want to trade in more liquid zones, which means that the need for LTTRs still exists. Thus the concept of regional hubs combined with LTTRs may still be better for very small bidding zones.

5.2.7 Option 2.6: Market making with TSOs' support

This option involves market making at power exchanges in a more regulated manner with the support of TSOs, but without any requirements for market participants for mandatory market making. This option assumes that power exchanges have already tried to organise market making, but were unable to offer favourable conditions to possible market makers with the tools and resources available to power exchanges. ACER understands that if power exchanges would have sufficient tools in their hands to attract market makers, they would have already done so (without the need for regulatory intervention), because it is in their interest to improve liquidity.

While market making solution can coexist with allocation of LTTRs by TSOs, ACER understands that Article 9(1) of the Electricity Regulation does not require TSOs to intervene in forward market two times, i.e. (i) by allocating LTTRs and (ii) by having equivalent measures in place to allow for market participants to hedge price risks across bidding zone borders. From this perspective, this option could be combined with allocation of LTTRs only if Article 9(1) of the Electricity Regulation would be amended with this regard.

This option aims to improve supply or demand order books is specific bidding zones, be it for futures, CfDs or other hedging products (e.g. Z2H LTTRs). To increase liquidity of these hedging products, the relevant power exchange(s) or TSO(s) would perform a tender for a market maker function under the framework where the TSO(s) pay the price/fee that the market maker demands for performing such service. The TSO(s) therefore do not perform the market making themselves, but instead only finances the costs the market maker is charging for this service. The costs of performing this function would ultimately be recovered through network tariffs or other appropriate mechanisms determined by the competent regulatory authorities.

Market makers support the liquidity directly, by being obliged to submit buy and sell orders with a predefined maximum bid-ask spread and minimum volume. A lower bid-ask spread and increased volumes in order books enable market participants to reduce trading costs and allow then an easier exit or entry into positions. Additionally, higher volumes in order books reduce the liquidity risk for speculative traders, which may in turn increase liquidity further.

The efficiency of market making support depends on the requirements imposed on market makers regarding the bid-ask spread and required volumes. The right level can be decided based on consultation with market participants and analysis of regulatory authorities. The potential market makers are selected based on the price or fee they demand for fulfilling the market maker function during the requested time period. The selection criteria must be objective and non-discriminatory. It can be expected that a narrower bid-ask spread and higher required volume would lead to a higher demanded price/fee. As the demanded price/fee depends on market volatility and the risk assessment of potential market makers, the outcome of the selection process is quite uncertain.

Benefits of this option

The benefit of this option is that it strengthens and increases liquidity in forward markets and does not split liquidity by introducing new alternative hedging products. It also allows to tailor this measure only to bidding zones with insufficient hedging opportunities.

Another benefit of enhancing market making is that it does not require changes in the market design and can be implemented within a short timeline.

In this option TSO does not need to take part in the market or become a market participant and has no strategic interest. Compared to other options where TSOs allocate long-term cross-zonal capacities, this option does not entail the risk of undervaluation of capacities.

Drawbacks of this option

Besides the uncertain costs for market making service, another drawback of this option is that it is not an efficient measure in bidding zones with asymmetric production and consumption. A basic strategy for a market maker is to minimise its open position. If a market maker's bid is matched on one side of the order book, the market maker will adjust the order book (to maintain the required bid-ask spread) in such a way that it is more probable that next time a bid on the other side of the order book will be matched and thus reduce the open position of the market maker. This strategy is difficult to execute in a bidding zone with much higher consumption than generation or the opposite. A market maker has in such a bidding zone an incentive to bias its bid-ask spread in such a way that minimal trades are made between the market maker and the dominating side in the bidding zone which fails to achieve the very purpose of the intervention[12].

Another drawback is that this option may lead to high costs for TSOs (and indirectly for consumers), although this may be mitigated by the flexibility to cancel the tendering outcome. In case there are more than one power exchanges active inside a bidding zone, TSOs would have two options. In the first option, the TSO(s) would support market making at all of these power exchanges to enable level playing field among them. However, this would lead to disproportionately high costs because less liquid exchanges are expected to induce higher costs for market making. In the second option, the TSO(s) would select a power exchange based on a tender, but this would have a very negative consequence for liquidity at non-winning power exchanges. ACER therefore considers that this option is not suitable in case of multiple power exchanges competing inside a bidding zone.

Finally, as pointed out by some responds to the consultation, the market maker solution does not tackle the fundamental issues behind low liquidity and in the long run hides these fundamental problems or makes them even worse. Market making is expected to be more successful in markets where liquidity is already quite good, but in markets with very poor liquidity, where this measure would be most needed, the costs of market making would likely be very high.

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[12] http://www.nordicenergyregulators.org/wp-content/uploads/2015/12/TE-2015-35-Measures-to-support-the-functioning-of-the-Nordic-financial-electricity-market.pdf and FCA-Konsultrapport-Measures-to-improve-hedging-opportunities-on-the-electricity-market-in-Sweden.pdf (ei.se)

5.3 Type of products offered by TSOs

This category of policy options identifies options on the type of products TSOs would allocate in case of explicit allocation of long-term cross-zonal capacities. In case long-term cross-zonal capacities are allocated implicitly via market coupling, the underlying products are by default obligations (i.e. CfDs or futures) and these cases are not considered in the following policy options.

5.3.1 Option 3.0: Status quo (PTR options and FTR options)

The current FCA Regulation provides a framework which enables to issue LTTRs in a form of PTR options with Use-It-Or-Sell-It (UIOSI) principle and FTR options or obligations. However, only PTR options and FTR options are currently used on different borders, whereas FTR obligations are not used on any bidding zone border.

PTR options and FTR options are auctioned on a bidding zone border in both directions (here we call these "oriented bidding zone borders"), i.e. PTR from zone A to zone B and PTR from zone B to zone A.

PTR options with UIOSI are physical transmission rights give the right to the holder to nominate physically the electricity exchange on the concerned oriented bidding zone border. The UIOSI principle refers to the case when the holder decides not to exercise this right (i.e. not to nominate the physical exchange), the holder receives from the TSOs the market spread (i.e. day-ahead price difference) on the concerned oriented bidding zone border, if positive, for each MW of PTRs it holds. In case the market spread on the concerned oriented bidding zone border is negative, there is no financial exchange between TSOs and PTR holder.

FTR options are financial transmission rights which give the right to the FTR holder to receive from the TSOs the market spread (i.e. day-ahead price difference) on the concerned oriented bidding zone border, if positive, for each MW of FTRs it holds. In case the market spread on the concerned oriented bidding zone border is negative, there is no financial exchange between TSOs and FTR holder.

PTR options with UIOSI and FTR options are financially fully equivalent – they offer the same level of hedging to the holder[13]. Consequently, most PTR holders decide not to nominate PTRs physically and rather receive the market spread remuneration which makes the use of these PTRs equivalent to FTR options.

Regarding the choice between PTRs and FTRs, the academic literature outlined in section 1.3, indicates superiority of FTRs over PTRs, the latter negatively affecting seller and buyer market power. PTRs are also problematic with regard to full financial firmness (the physical impact of PTRs on operational security cannot be removed) and would not be compatible with Option 3.3.

Benefits of this option

Most market participants expressed preference for PTR/FTR options in the public consultation. They report that PTR/FTR options allow more flexibility to market participants with physical positions as they limit the risk only in the exposed direction (i.e. when day-ahead market spread is above expectation) but do not take away the benefits or expose them to risks

[13] Except in very specific cases such as scarcity situations (curtailment in day-ahead market) where FTR holder would be exposed to imbalance prices which may be higher than DA prices, whereas PTR holder would still be exposed to day-ahead prices.

when day-ahead market spread is below expectation. Market participants also report that PTR/FTR options are more attractive for speculation, which improves competition for PTR/FTR options.

Drawbacks of this option

PTR/FTR options raise several concerns regarding the objectives of efficient forward market functioning. These have been partly explained above and summarised here:

1. Hedging with FTR options is more costly as the values of FTR options represent only positive market spread, which may be significantly higher than average market spread. Higher prices also mean higher costs of collaterals.[14]
2. The value of FTR options is more difficult to estimate. Market participants need to forecast prices for each market time unit during delivery period and then take the average of the positive values. This may be quite a challenge for FTR options with long maturity times and delivery periods.
3. PTR/FTR options are not well suited to integrate forward markets. Integration of forward markets with cross-zonal capacities would require an arbitrage between two markets, i.e. buying/selling futures in one bidding zone, buying PTRs or FTRs and selling/buying futures in another bidding zone. As futures are predominant hedging contracts in zonal forward markets, PTR/FTR options are not compatible with such arbitrage as they do not enable risk-free arbitrage or such arbitrage comes at a higher cost than necessary.
4. FTR options may significantly reduce the volume of allocated FTRs. First, because FTR options do not allow for netting of cross-zonal capacity and no capacity can be allocated in the opposite direction due to allocation of FTR options. Second, in FTR options the cross-zonal capacity is usually allocated fully in both directions, which means there are no capacity leftovers. This means that the objective of having daily auctions or continuous trading with capacity leftovers as foreseen in Option 2.1 would be significantly reduced. Such trade would be possible only if market participants (re)sell some FTR options and thereby release some previously allocated capacity.
5. Having both FTR options and obligations would contribute to market fragmentation as it would establish three different products per bidding zone or per border with different prices and separate secondary markets.
6. In light with the difficulty of FTR options valuation, FTR options are likely significantly contributing to undervaluation as discussed in Problem 8. Hence, keeping FTR options may not be able to address this problem. While undervaluation on the one hand causes loss of congestion income for TSOs and end consumers, it on the other hand means significant risk-free profits for market participants. This may partly explain the preference for PTR/FTR options.

5.3.2 Option 3.1: PTRs and FTR options with reduced firmness

In a coupled day-ahead market the LTTRs are reallocated in the day-ahead coupling and the congestion income from this reallocation is transferred to LTTR holders. This balanced mechanism does not work in the case of a decoupling. Here, LTTR holders are not remunerated with the congestion income from capacity reallocation, because capacity is reallocated through fallback explicit auction, but LTTR holders still receive the day-ahead market spread, which is usually even higher if the markets are decoupled. In addition,

[14] Typical collateral requirements for Futures contracts are in the range of 10% of its value. Currently FTR options at SAP require collateralisation for 100% of the value for the first two months of delivery.

remunerating LTTR holders with the market spread provides no incentive to LTTR holders to participate in the fallback explicit auctions. Hence, the congestion income received from fallback explicit auctions is significantly lower than remuneration costs and this financial loss represents a (temporary) financial burden for TSOs and is ultimately recovered via network tariffs.

This option proposes that the LTTR remuneration in the event of a decoupling is not based on the decoupled market spread, but instead on the congestion income collected from the reallocation through the fallback explicit auction.

Benefits of this option

The benefit of such option is that it could provide more incentives to LTTR holders to take part in the fallback explicit auctions which would lead to a more efficient auction outcome and to a lower market spread. It could also reduce financial burden for TSOs and consequently also for consumers paying network tariffs.

Drawbacks of this option

Reducing firmness of LTTRs would contradict the very objective of these products, which is to provide hedging opportunities. Reduced firmness would expose market participants to higher risks, which could make them value these products less and this would potentially result in a loss of congestion income that potentially could on average surpass the loss of TSOs in case of decoupling. This is supported by the fact that TSOs are better able to manage the risks that decoupling events entail than market participants, hence putting this risk on them would lead to worse market outcome than keeping the risk at TSOs. Furthermore, TSOs, together with NEMOs are responsible for market coupling and should have some possibility to impact it. Therefore, it makes sense that, despite cost recovery for such losses, TSOs have at least temporary financial incentives to impact market coupling organisation, such that it minimises the likelihood of such events.

5.3.3 Option 3.2: FTR obligations

FTR obligations entitle its holder to receive from a TSO a remuneration equal to the market spread if positive and oblige its holder to provide financial remuneration to the TSO equal to market spread if negative. Hence, the settlement of an FTR obligation equals, and will reflect, the average price differential for the delivery period.

FTR obligations are allocated on a bidding zone border (or Z2Z or Z2H) with a standard direction (e.g. from hub-to-zone) and there are no FTR obligations allocated in the opposite direction because it is already covered by the standard direction. They are usually priced lower than FTR options and can also have negative prices.

Benefits of this option

FTR obligations offer a perfect hedge against the price differential. The benefits of FTR obligations correspond to the inverse of the drawbacks outlined in PTR/FTR options, namely:

1. FTR obligations provide a full hedge (i.e. full price lock-in) at the lowest cost. Hedging with FTR obligations is less costly as the values of FTR obligations are lower than for FTR options. This also reduces collateral requirements.
2. The value of FTR obligations is easier to estimate. The value of FTR obligation is a simple difference between two baseload prices (information on which is transparent

and known) and no forecasts for each market time period are needed.[15] This simplifies the monitoring and benchmarking of regulatory authorities when assessing the efficiency of pricing of LTTRs and forecasting the congestion income.

3. Arbitraging between forward markets with futures contracts is easier. Buying/selling futures in one bidding zone buying FTR obligations and selling/buying futures in another bidding zone provides a risk-free arbitrage at the lowest cost.
4. FTR obligations allow for netting of cross-zonal capacity and more capacity can be allocated in the opposite direction due to allocation of FTR obligations. FTR obligations also allow for capacity leftovers, which are needed for the objective of having daily auctions or continuous trading with capacity leftovers as foreseen in Option 2.1.
5. Having FTR obligations only would concentrate all liquidity in one single product per bidding zone or border and would thus avoid market fragmentation and support competition in the primary and secondary market.
6. FTR obligations may significantly reduce the problem of undervaluation due to the above benefits. This would reduce the loss of congestion income for TSOs and benefit end consumers.

Drawbacks of this option

The drawbacks of FTR obligations is that they do not offer the option to hedge only one direction, which may be the preferred type of products for some market participants. In particular, market participants without physical exposure may be faced with higher risk in case of negative market spread (which is limited in PTR/FTR options).[16] FTR obligations may therefore be more risky for speculation. Nevertheless, there is no reason to believe that this would actually reduce interest for speculation in FTR obligations. Higher risk does not automatically lead to less speculation, but rather to adjustment of risk premia. In comparison, futures contracts entail essentially the same risk as FTR obligations, yet they do not scare away the speculators. Power futures have much higher liquidity than power options.

5.3.4 Option 3.3: Full financial firmness

Although the concept of financial firmness of LTTRs has already been introduced in the existing FCA Regulation, in practice LTTRs are still not financially fully firm and thus not fully equivalent to products traded at financial markets. There are several exceptions which does not guarantee full financial firmness of LTTRs and most of these originate from historical development where LTTRs were allocated in the form of PTRs only, which do have an impact on physical flows in the network and thereby on operational security. However, with the transition to financial LTTRs only, these concepts linked to operational security of the network became obsolete.

5.3.4.1 *Curtailment in normal situations*

The need to curtail cross-zonal capacities originates from the assumption that allocated cross-zonal capacities can be physically nominated and would thus result in physical cross-border flows that could lead to operational security problems. However, in case LTTRs are purely

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[15] This is particularly important for smaller market participants which have easy access to information on baseload prices, but are not able to invest into complex forecasting of prices in each market time unit.

[16] This is not the case for market participants with physical exposure (producers and consumers) whose risk of negative market spread is fully offset by their physical position.

financial products, they have no impact on physical flows and operational security (in absence of LTA inclusion in day-ahead capacity calculation). Thereby, the choice to switch all LTTRs into FTRs allows the removal of the concept of curtailment. This implies that in small percentage of market time units, the volume of allocated long-term cross-zonal capacities will be higher that the volumes available and allocated in the day-ahead timeframe. In such cases TSOs are exposed to financial risk only, namely in some cases the actual remuneration price can be higher or lower than the price paid for the LTTR.[17] This risk can be limited by the amount of offered cross-zonal capacities and should be covered by TSOs under the legal and regulatory framework providing a cost recovery comfort to cover any potential losses arising from bearing such risks.

5.3.4.2 *Curtailment in case of force majeure or emergency situation*

Similar to curtailment in normal operation as above, allocation of cross-zonal capacities in form of FTRs induce no physical consequences on the network and therefore no impact on operational security, which would require invoking of curtailment due to the force majeure or emergency situation. Hence full firmness of FTRs would require the removal of this concept from the legal framework for long-term capacity allocation (without prejudice to capacity allocation in short-term timeframes).

5.3.4.3 *Inclusion of long-term capacities in day-ahead capacity calculation*

Removal of the options to curtail capacity is only possible under assumption of no physical impact of allocated long-term cross-zonal capacities. To maintain this assumption, TSOs should remove any impact of allocated long-term cross-zonal capacities on the day-ahead capacity calculation. Therefore full financial firmness of FTRs require that the practice of inclusion of long-term cross-zonal capacities in the day-ahead capacity calculation be discontinued. Another option would be to maintain the inclusion of long-term cross-zonal capacities in the day-ahead capacity calculation, but allow for deviation in case of operational security concerns (i.e. capacity validation). It is important to note that this inclusion is not mandated by any legal requirement, but it is rather a voluntary practice by TSOs to ensure revenue adequacy resulting from remuneration of LTTRs.

5.3.4.4 *Compensation cap*

The removal of curtailment options would also generally remove the need for compensation cap. As indicated above, any financial risks and losses arising from full financial firmness should be covered by TSOs under the legal and regulatory framework providing a full cost recovery comfort to TSOs for these costs.

5.3.4.5 *Exemptions to LTTR remuneration*

Article 35 of the FCA Regulation provides two exceptions to remuneration of LTTRs which restrict full financial firmness of LTTRs. The first is the case when day-ahead capacity is being allocated with explicit auction, excluding cases of market decoupling (this exemption is not applicable to borders which have already implemented SDAC). The second exemption is related to allocation constraints, which limit the remuneration price in case long-term cross-

[17] Note that this price is not equal to the auction price of LTTR, because the auction price represents the average of all hourly prices during delivery period. Thereby even though the auction price may be lower than the remuneration price, this does not necessarily mean a financial loss for TSOs, because the remuneration price needs to be compared with the expected day-ahead price difference that market participants have factored in the offered bid price.

zonal capacity is offered but not re-allocated in the day-ahead timeframe due to allocation constraints. Full financial firmness would require both exemptions to be discontinued.

5.3.4.6 *Reduction periods*

LTTRs on some bidding zone borders currently include reduction periods for specific timeframe during delivery period, which usually represent maintenance of some assets that affect available capacity. In line with the above aim to provide LTTRs which are truly complementary to futures and forwards traded at power exchanges, such reduction periods should no longer be possible and allowed. Therefore any maintenance periods should be treated in some other ways. One of them is to offer only the amount of capacity that is available always during the delivery period, although this may not be adequate for HVDC interconnectors where capacity can drop to zero in case of maintenance. Another option would be to accept the risk that physical capacity is below the offered long-term capacity during such maintenance periods, which would expose TSOs to the risk of revenue inadequacy.

Benefits of this option

Ensuring full firmness of LTTRs would support the very objective of these products, which is to provide hedging opportunities. Full firmness of LTTRs would reduce the risks of the market participants which would reflect this reduced risk in their valuation of these products. This would expectedly lead to a higher congestion income received by the TSO. Furthermore, with a full financial firmness, the LTTRs would become true complement to the forward market products.

Drawbacks of this option

This option implies that the risk of revenue inadequacy or financial exposure for TSOs is increased. Even if this risk can be mitigated (through an adjustment of capacity being allocated to LTTRs), a cost-recovery comfort will need to be provided to fully cover this risk. These solutions can therefore increase the financial burden for TSOs and consequently also for consumers paying network tariffs (which should be offset by reduced undervaluation of LTTRs and benefits due to better forward market functioning).

6. ANALYSIS AND CONCLUSIONS

6.1 Available options

In this chapter we analyse the policy options identified above against the objectives in chapter 3. Policy recommendations beyond the FCA Regulation described in chapter 4 are not assessed.

6.1.1 The need for intervention

Four options are proposed in section 5.1 and analysed in this category:

- Option 1.0 – Status quo
- Option 1.1 – Coordinated assessment and decisions on TSOs' obligations
- Option 1.2 – Mandatory intervention
- Option 1.3 – No regulatory intervention

Options 1.0 and 1.1 are legally compliant with the legal framework of Article 9(1) of Electricity Regulation[18]. On the contrary, Option 1.2 and Option 1.3 would require an amendment of Article 9(1) of Electricity Regulation.

Evaluation of Option 1.0: Status quo

Market integration	Partly positive. This option facilitates market integration as it ensures support for forward market where this would be needed. However, national or bilateral decisions of regulatory authorities may not ensure consistent application of general principles.
Non-discrimination	Partly positive. While the option enables equal treatment of all market participants, the risk of non-consistent application of general principles regarding the support of forward markets may lead to a discrimination of market participants in some areas.
Competition	Partly positive. This option generally facilitates competition as it aims to improve competition in forward markets where this would be needed. However, in case of non-consistent application of general principles the competition may be hampered.
Efficient functioning	Partly positive. This option generally facilitates efficient functioning of the market as it ensures that TSOs' support to forward market is exempted only when such support is not needed. However, in case of non-consistent application of general principles the efficient functioning of the market may be hampered.
Efficiency	Partly positive. This option generally ensures regulatory support only when such support is needed. However, in case of non-consistent application of general principles this may not always be the case. This option also requires more administration from regulatory authorities for their individual or bilateral assessments and decisions.
Coherency	Partly positive. This options is coherent with existing solutions regarding regulatory support to forward markets. However, this option is not coherent with the general principles of EU-wide or regional coordination in the adoption of internal electricity market rules governing cross-border issues.

Evaluation of Option 1.1: Coordinated assessment and decisions on TSOs' obligations

Market integration	Positive. This option facilitates market integration as it ensures support for forward market where this would be needed. Regional decisions also contribute to market integration as it ensures regionally harmonised approaches to TSOs' exemptions.
Non-discrimination	Positive. This option does not discriminate any market participant or stakeholder.

[18] In accordance with Regulation (EU) 2016/1719, transmission system operators shall issue long-term transmission rights or have equivalent measures in place to allow for market participants, including owners of power-generating facilities using renewable energy sources, to hedge price risks across bidding zone borders, unless an assessment of the forward market on the bidding zone borders performed by the competent regulatory authorities shows that there are sufficient hedging opportunities in the concerned bidding zones.

Competition	Positive. This option facilitates competition as it aims to improve competition in forward markets where this would be needed.
Efficient functioning	Positive. This option facilitates efficient functioning of the market as it ensures that TSOs' support to forward market is only exempted based on regionally coordinated decisions by regulatory authorities.
Efficiency	Positive. This option ensures regulatory support only when such support is needed. It also simplifies the obligations of regulatory authorities for their assessments and decisions.
Coherency	Positive. This options is coherent with existing solutions regarding regulatory support to forward markets. It only adds regional coordination to the assessments and decisions of regulatory authorities which is coherent with the EU-wide or regional coordination in the adoption of internal electricity market rules governing cross-border issues.

Evaluation of Option 1.2: Mandatory intervention

Market integration	Positive. This option facilitates market integration as it ensures support for forward market by default.
Non-discrimination	Positive. This option does not discriminate any market participant or stakeholder.
Competition	Positive. This option facilitates competition as it aims to improve competition in forward markets by default.
Efficient functioning	Positive. This option facilitates efficient functioning of the market as it ensures that TSOs support the forward market by default.
Efficiency	Partly positive. This option may not be the most cost efficient, because it would require regulatory support even when such support would not be needed. It may therefore induce some regulated costs without additional benefits.
Coherency	Positive. This option is coherent with mandatory application of internal electricity market rules governing cross-border issues.

Evaluation of Option 1.3: No regulatory intervention

Market integration	Partly negative. This option assumes that no regulatory support to forward markets is needed. As this is unlikely scenario, this option would fail to support market integration where needed.
Non-discrimination	Partly negative. This option assumes that no regulatory support to forward markets is needed. As this is unlikely scenario, this option would increase discrimination of market participants in areas with poor access to forward markets.
Competition	Partly negative. This option assumes that no regulatory support to forward markets is needed. As this is unlikely scenario, this option would decrease competition in areas where forward market cannot be competitive without regulatory support.

Efficient functioning	Partly negative. This option assumes that no regulatory support to forward markets is needed. As this is unlikely scenario, this option would fail to facilitate functioning of the forward market.
Efficiency	Partly negative. This option assumes that no regulatory support to forward markets is needed. While this would save significant costs for TSOs and regulatory authorities, this option would fail to achieve the benefits of efficient forward market, which are expected to outweigh the costs.
Coherency	Partly negative. This option is not coherent with the rules governing other market timeframes, where market integration, competition and efficient functioning of the market is enhanced with the help of capacity allocation.

Table 1 summarises the evaluation of options on the need for intervention.

Table 1: Summary of the options on the need for intervention[19]

	Option 1.0 Status quo	**Option 1.1 Coordinated decisions**	Option 1.2 Mandatory intervention	Option 1.3 No regulatory intervention
Market integration	+	**++**	++	-
Non-discrimination	+	**++**	++	-
Competition	+	**++**	++	-
Efficient functioning	+	**++**	++	-
Efficiency	+	**++**	+	-
Coherency	+	**++**	++	-

- means partly negative, 0 means neutral, + means partly positive, ++ means positive, "/" means independent from

The choice of preferred policy option

The evaluation of options shows that Options 1.1 and 1.2 have generally positive contribution to the objectives. Because Option 1.1 scores higher in terms of cost-benefit efficiency, ACER considers that this option is the preferred policy option.

Expected benefits of the preferred option

The preferred option ensures regionally coordinated and harmonised approach in the assessment of the forward market and decisions by concerned regulatory authorities regarding the support of TSOs to forward markets. This should provide more consistent application of general principles (i.e. to support forward markets in case where forward markets cannot develop on its own). On the other hand, this option still enables TSOs to withdraw support to forward markets where regulatory authorities in the regions agree that such support is not needed and forward markets function sufficiently well without such support.

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[19] Option 1.2 and 1.3 are coloured in grey in the table as they do not respect the legal requirements set in Electricity Regulation Article 9 and are therefore not to be considered. Preferred policy option is indicated in bold.

With this regard, the regulatory intervention and support is limited only to cases where it is needed and justified.

Specific changes required to legal framework

The preferred policy option requires a clarification of Article 9(1) of Electricity Regulation that the assessment and decisions of regulatory authorities need to be done at regional level.

The preferred policy option would also require an amendment of the FCA Regulation, in particular its Article 30.

6.1.2 Type of TSO intervention

Seven options are proposed in section 5.2 and analysed in this category:

- Option 2.0 – Status quo
- Option 2.1 – Improved allocation and product timeframes
- Option 2.2 – Zone-to-zone LTTRs
- Option 2.3 – Zone-to-hub LTTRs
- Option 2.4 – Forward market coupling with CfDs
- Option 2.5 – Forward market coupling with futures
- Option 2.6 – Market making

Options 2.0 to 2.5 represent a gradation of the TSOs' intervention while option 2.6 can be considered as a different type of intervention by the TSO. Option 2.1 can be combined with Options 2.0 and 2.2 to 2.5.

Option 2.0 (Status quo) represents the current framework, which provides hedging products only between neighbouring bidding zones.

Evaluation of Option 2.0: Status quo

Market integration	Partly negative. As explained in the problem definition, this option has failed to integrate national forward markets to work as one single integrated market as it fails to match supply and demand for hedging across different bidding zones with the help of cross-zonal capacities.
Non-discrimination	Partly negative. This option does not facilitate equal access to hedging opportunities, since it does not facilitate access to hedging opportunities to market participants active in smaller and less liquid bidding zones.
Competition	Partly negative. This option cannot solve the existing problems of lacking competition between national forward markets and lacking competition and primary and secondary market for LTTRs.
Efficient functioning	Partly negative. This option does not facilitate efficient functioning of the forward market as it does not solve any of the problems described in the problem definition.
Efficiency	Partly negative. This options implies no change and no additional implementation or operational costs. However, this option would also not address any of the problems in the problem description and would therefore extend the negative consequences.
Coherency	Partly negative. This option is not coherent with the objective of fully integrated electricity market and not coherent with the way how integration

	is achieved with cross-zonal capacities in other market timeframes (i.e. implicit allocation).

Option 2.1 (Improved access) introduces the allocation of cross-zonal capacities in longer timeframes (up to 3 years ahead) and also includes more frequent auctioning and possibly continuous trading.

Evaluation of Option 2.1: Improved access

Market integration	Positive. The option facilitates forward market integration in timeframes up to three years ahead and provides cross-zonal hedging opportunities much more frequently than today. With this regard it is suitable to facilitate matching the supply and demand for hedging across different bidding zones with the help of cross-zonal capacities.
Non-discrimination	Positive. This option ensures no discrimination of any market participant or stakeholder.
Competition	Positive. Introducing more frequent access to LTTRs and up to 3 years ahead supports the forward markets, which makes access to hedging products easier. This promotes competition and reduces entry barriers both for futures as well as for LTTRs.
Efficient functioning	Positive. More frequent auctioning and access as well as the longer-term products would allow LTTRs to better integrate the existing national forward market, improve secondary markets and improve the overall functioning of the EU forward market.
Efficiency	Partly positive. This options imposes some implementation costs and higher operational costs for TSOs and Single Allocation Platform. However, the benefits of more frequent and longer-term access are expected to outweigh these costs.
Coherency	Positive. This option improves coherency with forward market functioning which is by nature continuous and extends beyond one year ahead.

Option 2.2 (Zone-to-zone LTTRs) allows for bidding and hedging between any two bidding zones.

Evaluation of Option 2.2: Zone-to-zone LTTRs

Market integration	Neutral. The option reduces barriers to trade between non-neighbouring bidding zones. However, this option still does not promise to integrate national forward markets to work as one integrated market.
Non-discrimination	Neutral. On the one hand, this option would ease the access for market participants for hedging between non-neighbouring bidding zones and thereby improve proxy hedging. On the other hand, this option would likely worsen the forward market liquidity in small zones.
Competition	Negative. This option introduces many more LTTRs which would further fragment the market and decrease competition for LTTRs in the primary and secondary market. This could be partly resolved with the flow-based allocation.

Efficient functioning	Neutral. This option slightly improves the market functioning, yet it still fails to address most of the problems in the problem definition.
Efficiency	Neutral. This option relies of existing infrastructure of capacity allocation at SAP with minor changes. This option entail little implementation costs for SAP, but may increase operational costs for SAP due to much more products being auctioned.
Coherency	Neutral. This option improves the integration of electricity market, yet it is still not coherent with the way how integration is achieved with cross-zonal capacities in other market timeframes (i.e. implicit allocation).

Option 2.3 (Zone-to-hub LTTRs) allows for bidding and hedging between any two bidding zones, but it adds an additional feature, which is the hedging against a hub. This option has the potential to attract much of forward trading from small bidding zones (but possibly also from big ones) in one or several hubs, which has the potential to significantly improve the forward market liquidity.

Evaluation of Option 2.3: Zone-to-hub LTTRs

Market integration	Positive. The option enables hub-based forward market, which aggregates supply and demand for hedging from different bidding zones. It also enables the use of cross-zonal capacities for providing hedging products to market participants for hedging the basis risk.
Non-discrimination	Positive. This option would provide much more equal access to hedging opportunities, since the access to hub-based hedging products would be equal. This is true also for the access to LTTRs to hedge the basis risk.
Competition	Positive. This option puts supply and demand for hedging from many bidding zones in direct competition at a common hub. It also reduces the number of different LTTRs which improves the competition in the primary and secondary market for LTTRs.
Efficient functioning	Positive. This option enables more liquidity concentrated at regional hubs complemented with accessible and liquid LTTRs for each bidding zone. This would make the forward market functioning in overall more efficient.
Efficiency	Positive. This option relies of existing infrastructure of capacity allocation at SAP and thereby does not require a completely new governance or framework. This option entail some implementation costs for SAP, but may also reduce operational costs for SAP due to less products being auctioned.
Coherency	Partly positive. This option introduces a more efficient implicit allocation of cross-zonal capacity similarly to other market segments. On the other hand it introduces the concept of hubs (and Z2H LTTRs), which are not familiar in existing market design in Continental Europe (but are in the Nordic region and Italy).

Option 2.4 (Forward market coupling with CfDs) is similar to Option 2.3 in design and only presents a difference in the venue offering the buying and selling of Z2H hedging products.

Evaluation of Option 2.4: Forward market coupling with CfDs

Market integration	Positive. The option enables hub-based trading which aggregates supply and demand for hedging from different bidding zones. It also enables the use of cross-zonal capacities for providing hedging products to market participants for hedging the basis risk.
Non-discrimination	Positive. This option would provide much more equal access to hedging opportunities, since the access to hub-based hedging products would be equal. This is true also for the access to CfDs to hedge the basis risk.
Competition	Positive. This option puts supply and demand for hedging from many bidding zones in direct competition at a common hub. It also reduces the number of different required cross-zonal hedging products, which improves the competition for CfDs.
Efficient functioning	Positive. This option enables more liquidity concentrated at regional hubs and complemented with accessible and liquid CfDs for each bidding zone. This would make the forward market functioning in overall more efficient. It also enables a single trading venue for hub-based futures as well as Z2H CfDs.
Efficiency	Partly positive. This option requires a whole new framework for the operation of market coupling compatible with NEMO designation and competition. Yet, on the other hand, it enables a single venue for all forward trading for market participants.
Coherency	Partly positive. This option introduces a more efficient implicit allocation of cross-zonal capacity similarly to other market segments. On the other hand it introduces the concept of hubs and Z2H CfDs which are not familiar in existing market design in Continental Europe (but are in the Nordic region and Italy).

Option 2.5 (Forward market coupling with futures) is similar to Option 2.4, except that the products being subject to market coupling are not CfDs but instead zonal energy Futures. This option does not require any specific cross-zonal hedging products.

Evaluation of Option 2.5: Forward market coupling with futures

Market integration	Positive. The option enables automatic matching of supply and demand for forward market products across all bidding zones with the help of cross-zonal capacities.
Non-discrimination	Positive. This option would provide much more equal access to hedging opportunities, since the liquidity of forward markets in small zones would be combined with the liquidity from neighbouring bidding zones with the help of cross-zonal capacities.
Competition	Positive. This option puts supply and demand for hedging from many bidding zones in direct competition with the help of cross-zonal capacities and without any need for additional cross-zonal hedging products.

Efficient functioning	Partly positive. This option concentrates all forward trading into zonal futures without the need for any additional cross-zonal products. On the other hand, this option is still vulnerable to change of bidding zones and may not address liquidity problems in very small zones (e.g. offshore bidding zones.
Efficiency	Partly positive. This option requires a whole new framework for the operation of market coupling compatible with NEMO designation and competition. Yet, on the other hand, it enables a single venue for all forward trading for market participants.
Coherency	Positive. This option introduces a more efficient implicit allocation of cross-zonal capacity similarly to other market segments. It is also coherent with existing zonal forward markets in Continental Europe (but not in Nordic region and Italy).

Option 2.6 (Market making) is completely different to the other options regarding the type of TSO intervention. Its potential is limited in case of a structural lack of generation/supply or demand in a bidding zone.

Evaluation of Option 2.6: Market making

Market integration	Neutral. The option is national only intervention and has no impact on market integration, as it only aims to improve the liquidity of hedging products within a single bidding zone.
Non-discrimination	Partly positive. This option would increase access and liquidity in smaller bidding zones. However, this effect may be limited due to structural lack of supply and demand inside the zone, which can only be solved by integrating smaller zones with other zones.
Competition	Partly positive. This option improves the competition for forward products in national forward markets. However, such competition may come at a cost for network tariffs and may be considered as artificial and does not represent a permanent solution for competition.
Efficient functioning	Partly positive. This option support efficient functioning of the market, because it enhances liquidity and competition in specific bidding zones. Yet, this kind of competition may come at significant cost and may not solve the liquidity problems in an enduring way.
Efficiency	Positive. This option may provide significant benefits as a temporary solution in case of insufficient competition. The costs of this option can be limited by the tendering conditions of the market making by the TSO, allowing this option to be efficient from a cost-benefit perspective.
Coherency	Partly positive. This option is coherent with the policy of enhancing competition and access to the market to all market participants.

Table 2 provides a summary of the options on the type of TSO intervention.

Table 2: Summary of the options on the type of TSO intervention[20]

	Option 2.0 Status quo	**Option 2.1 Improved access**	Option 2.2 Z2Z LTTRs	**Option 2.3 Z2H LTTRs**	Option 2.4 CfD coupling	Option 2.5 Futures coupling	Option 2.6 Market making
Market integration	-	**++**	0	**++**	++	++	0
Non-discrimination	-	**++**	0	**++**	++	++	+
Competition	-	**++**	0	**++**	++	++	+
Efficient functioning	-	**++**	0	**++**	++	+	+
Efficiency	-	**+**	0	**++**	+	+	++
Coherency	-	**++**	0	**+**	+	++	+

--, means negative, - means partly negative, 0 means neutral, + means partly positive, ++ means positive, "/" means independent from

The choice of preferred policy option

Based on the above evaluation of policy options, ACER prefers Option 2.3. This option maximises the positive contribution to objectives and to addressing the problems. In particular, this option allows for aggregation of forward market liquidity at regional hubs and is preferred over Option 2.4 because of its simplicity and lower costs. On the other hand, Options 2.4 is also a promising option that may be suitable for those regions where CfDs already exist and where a shift to LTTRs would be considered as too disruptive. For this reason, ACER proposes this option to be an alternative for the cases where all regulatory authorities in a region agree on implementing this option. This option would, therefore, constitute an "equivalent measure" as referenced in Article 9(1) of the Electricity Regulation.

Option 2.3 (or Option 2.4) should be combined with Option 2.1, which ensures the allocation of cross-zonal capacities in longer timeframes and much more frequently than today.

ACER considers that Option 2.6 is also suitable for a specific targeted intervention to supplement forward markets in specific bidding zones. However, this option cannot be considered as a European solution for addressing the problems related to electricity forward market as it does not integrate electricity forward markets to function as one market.

ACER discards Options 2.0 and 2.2, because they are not able to solve the existing problems and are not contributing enough to the objectives. While Option 2.5 is also a promising option in terms of objectives and problems solved, it is less preferable compared to Option 2.3 and 2.4.

Expected benefits of the preferred option

Option 2.3 (or 2.4) are promising to provide a fairly liquid access of cross-zonal hedging products to hedge the risk between each bidding zone and a common regional hub. The liquidity of these hedging products would be facilitated by:

[20] Options colored in light blue are independent and can be combined with other options. Preferred policy options are indicated in bold.

(i) daily/weekly auctions possibly combined with continuous market (providing more frequent access to LTTRs);
(ii) less fragmentation (due to only one product per bidding zone);
(iii) allowing market participants to buy and sell LTTRs (liquidity not limited by cross-zonal capacity);
(iv) allocating LTTRs with maturities up to 3 years ahead; and
(v) liquid secondary market (with daily/weekly auctions possibly combined with continuous market and possibility to (re-)sell LTTRs).

The above benefits of LTTR market are expected to make the hedging products at regional hub much more attractive than existing hedging products in individual bidding zones. As a result, this option aims to attract and aggregate the forward market liquidity at regional hubs, mostly because all cross-border hedging products offered by TSOs are provided towards such hub. These hedging products at regional hubs are expected to provide a better proxy hedge for most of the bidding zones, which currently use other proxy hedging strategies. If sufficient liquidity is attracted at regional hub, this may also improve liquidity beyond 3 years ahead. Finally, the liquidity of regional hubs would not be endangered in case of any changes of bidding zone configuration.

Specific changes required to legal framework

The legal framework of Article 9 of the Electricity Regulation seems generally fit for purpose to accommodate the above preferred policy options. The only change required to facilitate market making is to allow TSOs to support the market making even they already support the forward market with LTTRs or equivalent measures (e.g. CfDs).

The preferred policy options would, however, require a significant amendment of the FCA Regulation, both in terms of capacity calculation as well as capacity allocation.

6.1.3 <u>Type of products offered by the TSO</u>

Three options were identified in this category (section 5.3):

- Option 3.0 – Status Quo with PTRs and FTR options
- Option 3.1 – PTRs/FTRs with reduced firmness
- Option 3.2 – FTR obligations combined with FTR options
- Option 3.3 – Full financial firmness

ACER understands that these options are only relevant in combination with Options 2.0, 2.2 and 2.3 since other options in section 5.2 do not relate to LTTRs.

Evaluation of Option 3.0: PTR options and FTR options

Market integration	Partly positive. Supports forward market in general, but not entirely suitable for arbitraging between two forward markets based on futures contracts.
Non-discrimination	Neutral. Has no impact on non-discrimination.
Competition	Partly positive. Enables cross-border hedging in specific direction, but comes at a higher hedging costs and higher collateral requirements. Less supportive of secondary market.
Efficient functioning	Partly positive. Supports proxy hedging to some extent, yet it is less supportive of secondary market with capacity leftovers.

Efficiency	Positive. This options imposes no significant costs of implementation as it represents the status quo.
Coherency	Partly positive. This option complement the forward market, but is not entirely compatible with futures contracts as the main contract in the forward market.

Evaluation of Option 3.1: PTR options and FTR options with reduced firmness

Market integration	Partly negative. While the option still provides some cross-border hedge, because of reduced firmness, such hedge cannot be considered efficient hedge and does not support integration of forward markets.
Non-discrimination	Neutral. Has no impact on non-discrimination.
Competition	Partly negative. It makes PTRs and FTRs less attractive for hedging and more risky. This reduces the interest and competition for these products.
Efficient functioning	Negative. It does not complement forward markets based on futures. It does not support proxy hedging.
Efficiency	Negative. This options imposes no significant costs of implementation. However, the benefits are expected to be negative.
Coherency	Negative. This option does not complement the forward market as it provides hedging products not compatible with futures contracts, which are the main contracts in the forward market.

Evaluation of Option 3.2: FTR obligations

Market integration	Positive. Suitable for direct arbitraging between two forward markets. Supports forward market in general. Supports integrating forward markets.
Non-discrimination	Neutral. Has no impact on non-discrimination.
Competition	Positive. Promotes competition, reduces the cost of hedging and consequently collaterals for market participants.
Efficient functioning	Positive. Provides effective hedge at the lowest cost and supports liquid forward markets, including secondary market.
Efficiency	Positive. This options imposes no significant costs of implementation. The benefits are expected to significantly outweigh the costs.
Coherency	Positive. This option is compatible with forward markets based on futures contracts.

Evaluation of Option 3.3: Full financial firmness

Market integration	Positive. Supports forward market in general and their integration as it provides a full hedge similar as futures contracts.
Non-discrimination	Neutral. Has no impact on non-discrimination.

Competition	Positive. Promotes competition as it makes the hedging products more attractive for hedging.
Efficient functioning	Positive. Provides effective hedge and allocates the firmness risk to TSOs who are better able to manage this risk.
Efficiency	Partly positive. This options imposes some changes on TSOs and regulatory authorities regarding firmness risk and costs. The benefits are, however, expected to outweigh the costs.
Coherency	Positive. This option is more compatible with forward markets based on futures contracts.

Table 3 summarises the evaluation of options on the type of products proposed by TSOs.

Table 3: Summary of the options on the type of products proposed by TSOs

	Option 3.0 FTR/PTR options	Option 3.1 Reduced firmness	**Option 3.2 FTR obligations**	**Option 3.3 Full financial firmness**
Market integration	+	-	**++**	**++**
Non-discrimination	0	0	**0**	**0**
Competition	+	-	**++**	**++**
Efficient functioning	+	--	**++**	**++**
Efficiency	++	--	**++**	**+**
Coherency	+	--	**++**	**++**

--, means negative, - means partly negative, 0 means neutral, + means partly positive, ++ means positive, “/” means independent from

The choice of preferred policy option

Given the above, ACER prefers Options 3.2 and 3.3, which are FTR obligations with full financial firmness as the standard product offered by TSOs. This is because of the expected benefits of FTR obligations and full financial firmness in terms of contributing to objectives and addressing the problems. Depending on the choice of how hub prices would be defined in Option 2.3, FTR options with full financial firmness could be offered complementary to FTR obligations. However, before deciding to do so, the above concerns about their impact would need to be thoroughly investigated.

Option 3.1 with reduced firmness is not preferred, because it significantly undermines the very objective of hedging products, which is to provide a hedge against the underlying risk, including the risk of decoupling. If regulatory authorities conclude that the forward market needs regulatory support, it would be counterproductive that the supports being offered from such support would not provide efficient hedging opportunity (i.e. 100% hedge). Such a position would contradict the very essence of the underlying conclusion that the forward market needs regulatory support.

Expected benefits of the preferred option

FTR obligations with full financial firmness are expected to:

(i) reduce hedging costs and access to the forward market;
(ii) simplify the valuation of FTRs from market participants as well as benchmarking and forecasting for TSOs and regulatory authorities;
(iii) promote risk-free arbitrage between forward markets;
(iv) decrease market fragmentation (one single standard product per bidding zone);
(v) increase competition (due to (i) and (iii) as well as capacity netting and secondary market with capacity leftovers);
(vi) reduce undervaluation (easier valuation and more competition).

Any complementary FTR options should be assessed against the risk of losing these benefits.

Specific changes required to the legal framework

The legal framework of Article 9 of the Electricity Regulation seems generally fit for purpose to accommodate the above preferred policy options. Nevertheless, strengthening Article 9 of the Electricity Regulation with references to FTR obligations and full financial firmness would be beneficial to provide legal certainty.

The preferred policy options would also require a significant amendment of the FCA Regulation, focusing on FTR obligations and removing all elements against full financial firmness.

7. RECOMMENDATIONS AND PROPOSED ACTIONS

In conclusion, ACER identifies that existing electricity forward markets in the EU suffer from a number of problems which prevent achieving the objective of an effective and efficient electricity forward market. The main shortcoming of existing forward markets is that they do not function as a single integrated forward market. This objective was largely achieved in the day-ahead and intraday timeframe (soon also in the balancing timeframe) with the help of (implicit) cross-zonal capacity allocation between bidding zones. However, in the forward timeframe, the long-term capacity allocation is not designed in a way that would integrate national forward markets in the most efficient way.

In order to address the problems and achieve the objectives, ACER proposes several improvements to the electricity forward market.

Part of these proposed improvements pertain to the forward markets in general, for which ACER and NRAs are not always the competent authorities. Considering the scope of those general policy recommendations, ACER invites relevant authorities to strive to (i) improve the market structure, aiming at improving the competition in the forward market, (ii) reduce existing hedging disincentives that exist in many Member States, (iii) review the current definition of the bidding zones and, finally, (iv) reduce the current barriers to trade at organised marketplaces.

The main part of the proposed improvements relates to better allocation of long-term cross-zonal capacities in a way that integrates national forward markets into a more integrated EU forward market and are assessed against the defined objectives.

First, ACER proposes to harmonise the legal framework governing how TSOs support the functioning of the forward market. ACER proposes that TSOs should by default issue LTTRs or have equivalent measures in place to support forward market, except where regulatory authorities of the concerned region agree to exempt TSOs from such obligations, based on an assessment demonstrating that such support is not needed.

As regards the TSOs' support to forward markets with LTTRs, ACER identifies that zone-to-hub FTRs is the most suitable option to support the forward market. This is expected to attract and gather liquidity of national forward markets into regional hubs. These regional hubs promise to attract much higher liquidity than national forward markets and are independent on the size and change of bidding zones. Nevertheless, such regional hubs must be complemented by liquid or frequently accessible zone-to-hub FTRs. Thereby zone-to-hub FTRs should be complemented by an improved calculation and allocation of long-term cross-zonal capacities by TSOs in timeframes up to three years ahead of delivery with more frequent allocation of cross-zonal capacities.

In case regulatory authorities agree not to implement LTTRs but to rather ask TSOs to have equivalent measures in place to support the forward market, ACER identifies the option with coupling of zone-to-hub CfDs as the most suitable option to be implemented in such case.

All the above options can be complemented by national decisions to support forward market liquidity with market making.

ACER also recommends that transmission rights are allocated in a form of FTR obligations with a full financial firmness. At this stage ACER does not exclude the possibility of FTR options, which may be added only after careful evaluation of their impact on the efficient functioning of electricity forward market.

Finally, ACER notes that the proposed policy options need further evaluation within a proper impact assessment, which should accompany the future revision of the FCA Regulation.

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ANNEX I – TERMS USED

Throughout this document, the following terms are extensively used. They are therefore defined in this section to clarify their meaning.

Long Term Transmission Right (LTTR)

This term refers to a hedging contract between a TSO (or Single Allocation Platform (SAP)) and a market participant for the right to transmit electricity between two network locations based on cross-zonal capacity allocation. A TSO (or a SAP) is always a central counterparty to the holders of LTTRs. See sections 5.3.1 and 5.3.3 for more explanation.

Contract for Difference (CfD)

This term refers to a hedging contract traded at a power exchange which provides the holder the obligation to pay or receive the price difference between two underlying day-ahead (spot) prices. A power exchange (or its clearing house) is always a counterparty to holders of CfDs. The EPAD system currently present in the Nordic region is a form of CfD contracts.

Hub

This term refers to the aggregation of several locations where electricity prices are established (e.g. bidding zones) into a single aggregated price and location (based on agreed rules). A hub could, for example, be a region with a hub price defined as the weighted average price of every bidding zone within this region.

Market coupling

This term refers to a market mechanism in which energy products in different bidding zones are matched simultaneously with cross-zonal capacities.

Futures

This term refers to standard energy futures contracts traded at power exchanges which provide the holder the obligation to pay or receive the day-ahead (spot) price. A power exchange (or its clearing house) is always a counterparty to holders of futures.

Forwards

This term refers to (mainly) non-standardised energy contracts between market participants to buy or sell energy at a specified price at a future date. They differ to futures mainly in customisation, settlement and counterparty risk.

Secondary market

This term refers to a market that allows the market participants to exchange products acquired in a previous (primary) market.

Basis risk

This term refers to the risk remaining due to a mismatch between the exposure and a given hedging product. It implies that that the price to which one is exposed might not move in total and steady correlation with the price underlying the hedging product.

Proxy hedging

A hedging strategy to use of a price-correlated product to hedge a particular risk when a direct hedge for that risk is not available. In case proxy hedging is unable to minimise the basis risk, it should be combined with basis risk hedging.

ANNEX II – FINANCIAL TRANSMISSION RIGHTS IN NODAL MARKETS – THEORY AND PRACTICE

FTRs have been originally proposed by Hogan (1992) and successfully implemented, with slightly different features, in all liberalized markets based on Locational Marginal Pricing (LMP), including the United States.

In general and similarly to the definition of FTRs in the European market design, FTRs hedge the buyer against the market price difference between two or more price zones and they have no impact whatsoever on the economic dispatch or on the actual use of the transmission network according to Hogan (1992) and Battle et al. (2014).

Financial transmission rights (obligations or options) can be designed as point to point FTRs or as Flow Gate Rights (FGRs) that are directional rights defined over specific time intervals and specific links, entitling their holder to the shadow price on the link's capacity constraint in the designated direction per MW denomination. However, as assessed by Oren (2013) FGRs are rarely used in the markets nowadays since energy traders prefer FTRs that are more suitable for hedging point to point congestion risk. To compare those products to the different FTR products studied throughout this document for the European market design, FGRs show similar characteristics than the currently implemented bidding-zone-border FTRs. Point to point FTRs can be compared with zone-to-zone FTRs in a zonal market.

A central feature is the concept of revenue adequacy of FTRs to provide full funding and the associated transmission hedges that link transactions between different locations. Hogan (1992) shows that if the outstanding FTRs satisfy a "simultaneous feasibility test" and the network topology is fixed then the FTR market is "revenue adequate". Revenue adequacy means that congestion revenues and merchandising surplus (i.e., the difference between the buying cost and the sales revenues for energy traded through the pool) collected by the system operator from bilateral transactions and local sales and purchases at the LMPs, will cover the FTR settlements. The principle of revenue adequacy is also central in the transmission rights in the EU.

It is acknowledged that FTRs were developed primarily to replace physical firm transmission rights in markets based on economic dispatch and LMP, thereby enabling load serving entities (i.e. utilities that have a service obligation) and generators to continue entering long-term contracts. This is the crucial role remarked by many authors and system operators such as Hogan (2018) and PJM (2020). As proposed in the section 6.1.3 of this document, FTRs could also replace PTRs in Europe.

All liberalized markets in US and other markets based on LMP implemented hedging instruments that despite the different names refer to the FTRs instrument, as shown in Table 2 below:

Table 2: Nodal-based market experience with FTRs (overview)

Market	Financial transmission right	Auction revenue right
ISO NE (US)	FTR	ARR
NYISO (US)	Transmission Congestion Contract (TCC)	-
PJM (US)	FTR	ARR
MISO (US)	FTR	ARR
ERCOT (US)	Congestion revenue rights (CRR)	-
CAISO (US)	Congestion revenue rights (CRR)	
Southwest power pool (US)	Transmission congestion right (TCR)	ARR

Singapore	FTR
New Zealand	FTR

In general FTRs are issued by the Independent System Operator (ISO) through an auction and a priority allocation to load serving entities and project sponsors of transmission facilities may occur (Alderete (2016), House (2020), PJM (2017)).

An **Auction Revenue Right** is a Market Participant's entitlement to a share of revenue generated in annual FTR auctions. A Market Participant's firm historical usage of the ISO's transmission system determines its share and, depending upon the FTR auction clearing price of an ARR path, the share could result in revenue or a charge. ARR can be also converted into FTR, by scheduling this product in the FTR auction. This specific product is not present in the European market design nor in other non-US markets due to the different approaches followed regarding the historical usages of transmission systems.

In ISO markets where ARR are used, the allocation of rights to load serving entities and transmission sponsors is done through this sort of products which are auctioned up to multiple years prior to the delivery. Market participants may decide to: i) get the revenue stream from the FTR auction, ii) convert the ARR into FTR and iii) sell ARR into secondary market (see for example PJM (2017).

FTRs can be traded by any party, no matter if it is a participant that bids in the electricity market. This improves liquidity of the FTR market.

No cost allocation or priority allocation of FTRs to load serving entities demonstrates the aim of redistributing congestion costs and protecting loads against congestion risks.

Long-term contracts are usually a significant component of the electricity markets; the share of bilateral and self-supply contracts can be very high, as in the case of PJM (see**Error! Reference source not found.** PJM (2020)). In general, bilateral and self-supply contracts (with physical delivery) are notified to the pool run by the ISO and subject to the payment of congestion charges. In this last respect, the FTR market is an essential tool to ensure hedging.

Table 3: Method for supplying load in PJM day-ahead market (PJM 2020)

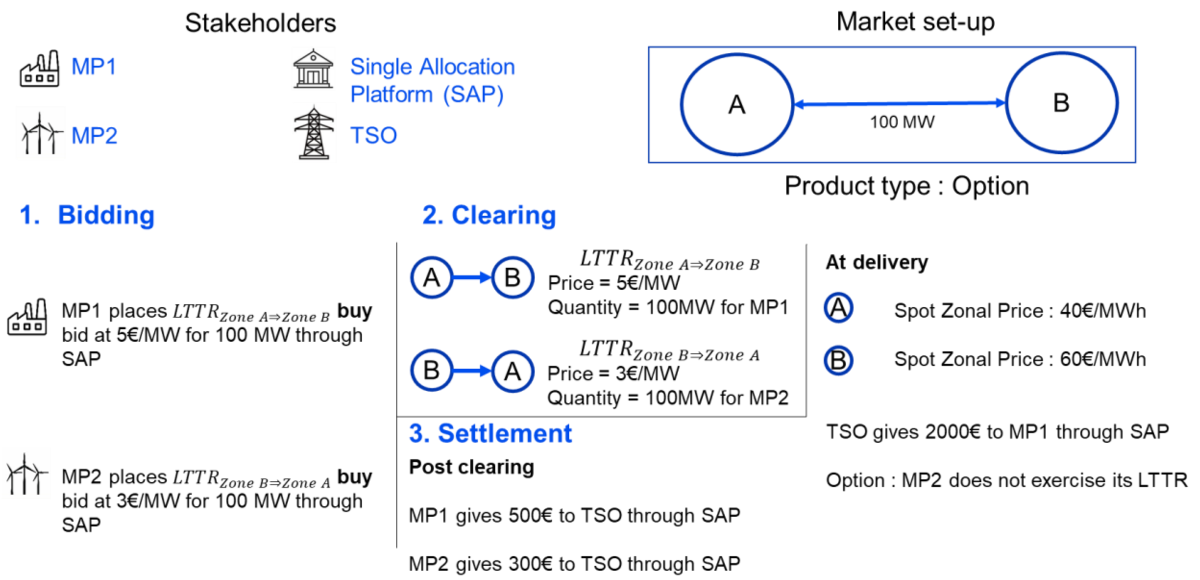
2008 - 2018	Spot Market	Self-supply and bilateral
Average	24.2%	75.8%

ANNEX III – EXAMPLES OF POLICY OPTIONS

This Annex presents concrete cases of policy options discussed in the main document. In all cases the values and units are normalised to one hour.

Case 1: Bidding Zone Border Long-Term Transmission Rights (BZB LTTRs)

In this type of arrangement, the TSOs and the Single Allocation Platform are involved. TSOs allocate long-term cross-zonal capacities and issue LTTRs (financial or physical) to market participants. Those LTTRs allow the market participants to hedge the price difference between two neighbouring zones (in a specific direction in case of PTRs or FTR options).



The above example is valid for the currently allocated FTR options or PTRs (FTR obligations are not considered here) where the market participants can hedge different borders and directions. The auction price and quantity is defined by a welfare optimization of the bids of the market participants and the volume of cross-zonal capacities offered by TSOs. In the settlement phase, there are two steps at which financial flows take place. First, following the LTTR auction, the market participant will pay to the TSO through the SAP the following amount:

$$Amount\ to\ pay = LTTR\ Volume * Auction\ Price\ of\ LTTR$$

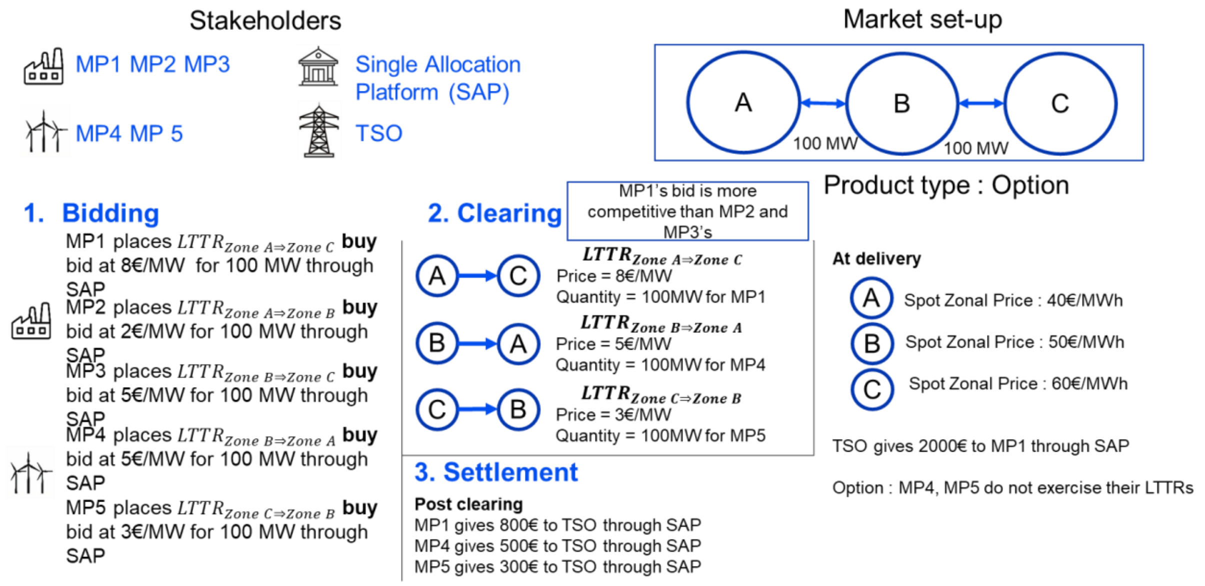
After delivery, the market participants (except those which choose to nominate PTRs) will receive from the TSO through the SAP the following remuneration (in case of obligations also the negative market spread is taken into account):

$$Amount\ to\ receive = LTTR\ Volume_{Zone\ A \Rightarrow Zone\ B} * \max(0, Zonal\ Spot\ Price\ B - Zonal\ Spot\ Price\ A)$$

This market arrangement is currently applied in continental Europe.

Case 2: Zone-to-Zone Long Term Transmission Rights (Z2Z LTTRs)

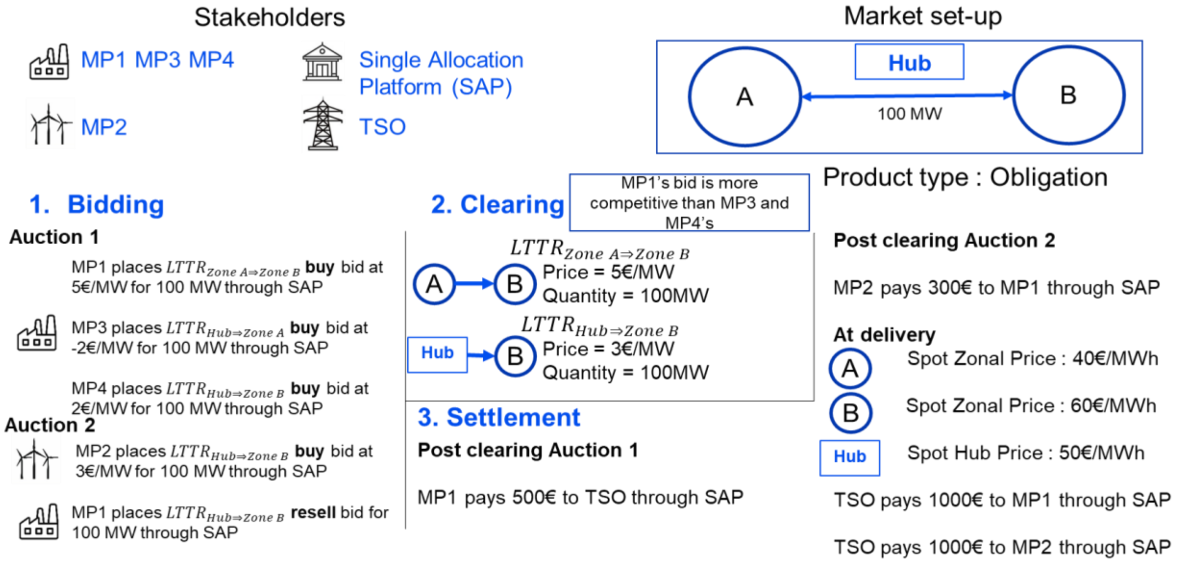
This type of arrangement is similar to LTTRs, but also adds the possibility to place LTTRs bids from a zone to another non-neighbouring zone. Based on a welfare optimization, competitive bids will be assessed in order to maximize the welfare of the auction.



The above example is illustrating a case with FTR options where a Z2Z bid (MP1) from Zone A to Zone C competes for cross-zonal capacity with the combination of two Z2Z bids (Zone A to B from MP2 and Zone B to C from MP3). As The first Z2Z bid (MP1) is more competitive (higher price) than the combination of the two Z2Z bids, it is cleared and the two Z2Z bids are not.

Case 3: Zone-to-Hub Long-Term Transmission Rights (Z2H LTTRs) – hub with ex-post variable parameters

This type of arrangement is similar to Z2Z LTTRs but also adds the possibility to place bids from a zone to a hub. Based on a welfare optimization, competitive bids will be assessed in order to maximize the welfare of the auction. This option differs depending on the options or obligations. For simplicity only the case of FTR obligations is shown in the example.

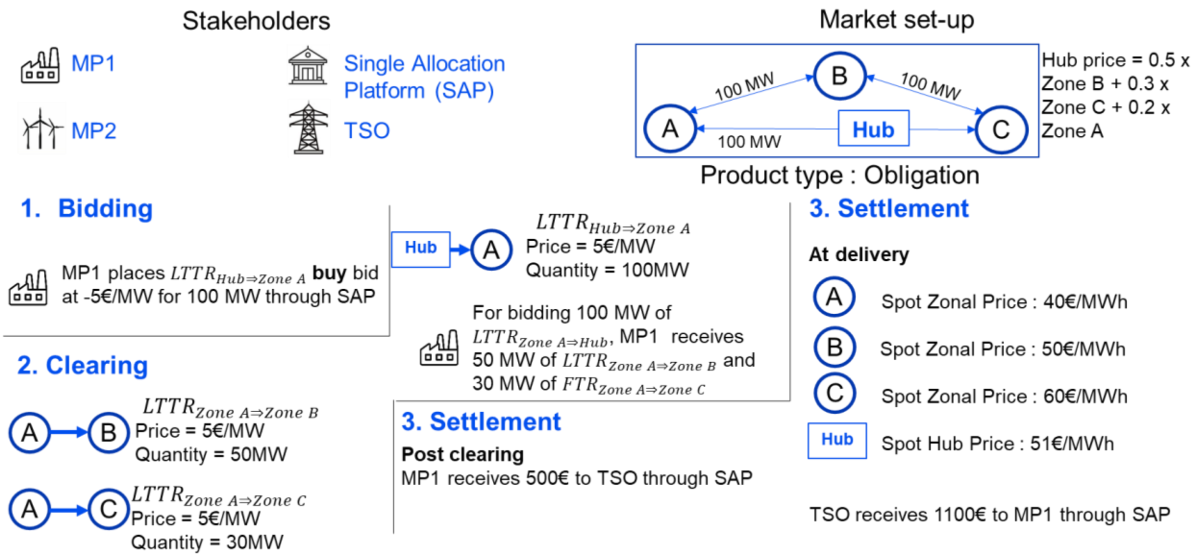


In the above example, a Z2Z bid (MP1) from zone A to zone B competes for cross-zonal capacity with the combination of two Z2H bids (zone A to hub from MP3 and zone B to hub from MP4). As the Z2Z bid is more competitive (higher price) than the combination of two Z2H bids, it is cleared and the two Z2H bids are not.

Also, the above example presents the situation in which a MP (MP1) places a resell bid of the previously acquired LTTR product through the SAP. This resell bid can be a price taking bid (shown in example) or specific price bid indicating that LTTR will be resold only if auction price is equal or higher than bid price.

Case 4: Zone-to-Hub Long-Term Transmission Rights – hub with ex-ante fixed parameters

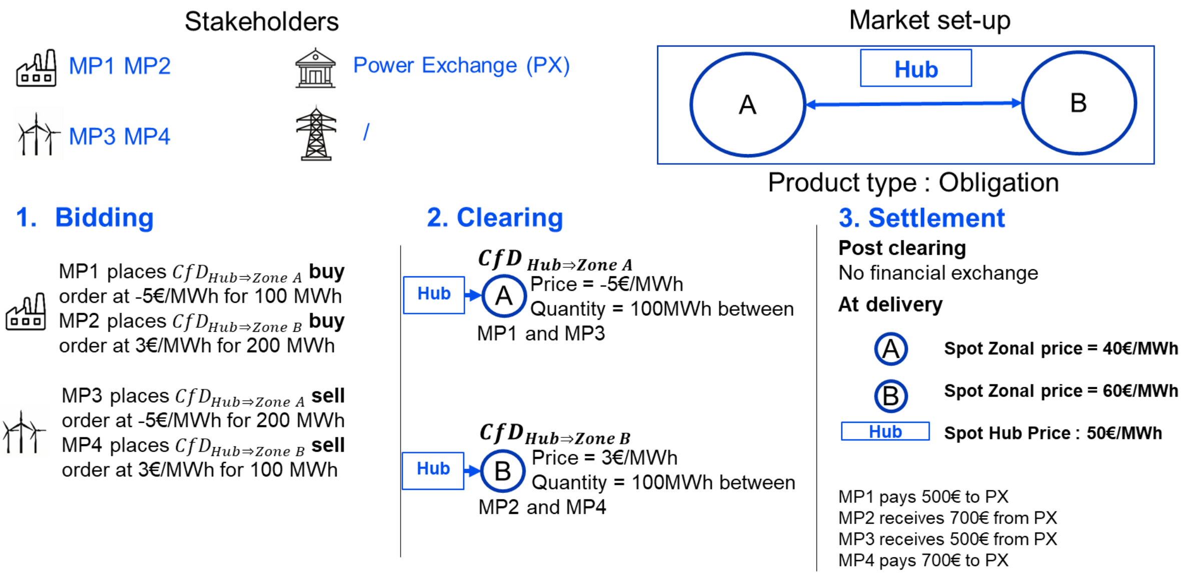
This type of TSO arrangement provides an alternative to Z2H LTTRs. The difference between this set-up and the Z2H LTTRs is the following:



In this arrangement, a hub price calculation will be defined prior to the LTTR market opening by applying “weights” to different zones. Those weights could be defined based on the traded volumes of the last year prior to the auction. When placing a LTTR Z2H bid, the market participant will receive a sum of multiple Z2Z LTTRs based on the same “weights” than the one used for the hub price calculation.

Case 5: Contract for differences (CfDs) without coupling

In this type of arrangement, TSOs are not involved. A PX offers trading with CfDs to market participants. Those CfDs allow the market participants to hedge the price difference between a zone and a hub.



In the above example, the supply and demand of CfDs in zones A and B is perfectly matched – there is no cross-zonal matching. In the settlement after delivery, the market participants will have the following financial flow through the PX (negative value indicate pay for buy orders):

$$Amount\ to\ pay/receive = CfD\ Volume * ((Zonal\ Spot\ Price - Hub\ Spot\ Price) - Matched\ CfD\ Price)\ [€/MWh]$$

This market arrangement is currently applied in the Nordic region.

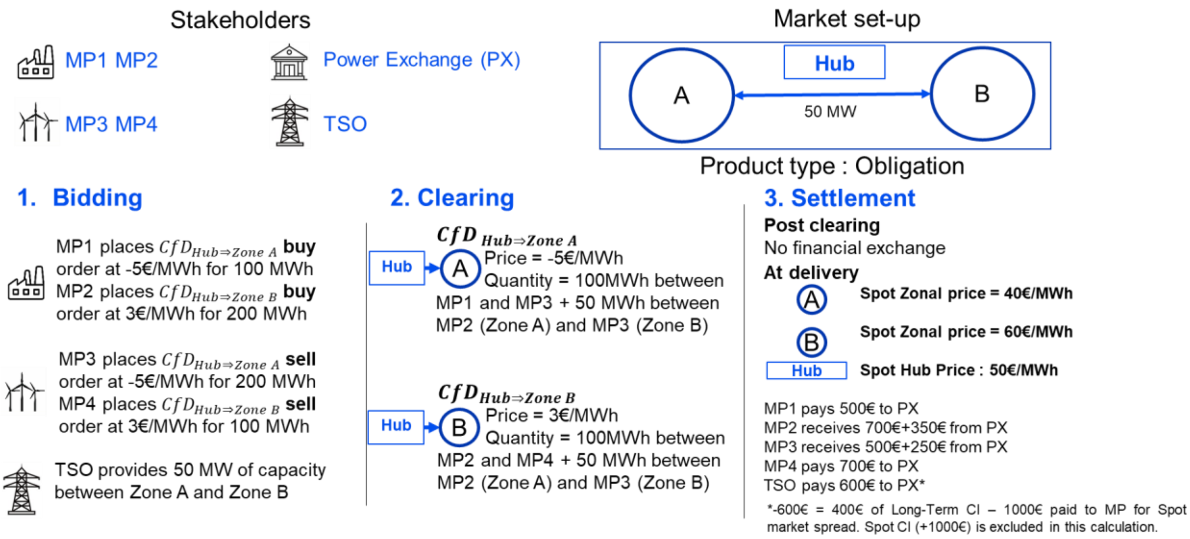
Case 6: Forward Market Coupling with Contracts for Difference (CfD Coupling)

This arrangement involves both TSO and PXs (NEMOs). In this set-up, the power exchanges offer trading with CfDs allowing for a hedge between a hub spot price and a zonal spot price. The TSO will offer capacity between the zones. Through a welfare optimization, the clearing will select the sell and buy orders while respecting the constraint of the cross-zonal capacity. Financial flows of the market participants are computed and settled in a similar way than in Case 5 with CfDs, namely market participants have to pay the matched price and receive the difference between zonal spot price and hub price (negative value indicate pay for buy orders):

$$Amount\ to\ pay/receive = CfD\ Volume * \big((Zonal\ Spot\ Price - Hub\ Spot\ Price) - Matched\ CfD\ Price\big)$$

The congestion income of the TSOs is computed as a difference between congestion income TSOs receive in the long-term timeframe when matching and coupling the CfDs and remuneration costs TSOs have to pay from the day-ahead congestion income (equivalent to LTTR remuneration) (negative value indicate negative income):

$$Congestion\ income_{\ Zone\ A \Rightarrow Zone\ B} = Interconnection\ capacity * \big((Matched\ CfD\ Price_{Zone\ B \Rightarrow Hub} - Matched\ CfD\ Price_{Zone\ A \Rightarrow Hub}) - (Zonal\ Spot\ Price\ B - Zonal\ Spot\ Price\ A)\big)$$



In the above example, the TSO receives as long-term congestion income resulting from forward market coupling the difference in clearing price of the CfDs in both zones multiplied by the provided capacity $(50 * (3 - (-5) = 400€)$ and at the delivery has to remunerate the difference in clearing price of the two zones multiplied by the provided capacity $(50 * (60 - 40) = 1000€\ )$ to PXs and MPs due to the reallocation of long-term cross-zonal capacity. The TSO therefore has a negative net congestion income because the long-term market spread was lower than the day-ahead market spread.

Case 7: Forward market coupling with futures

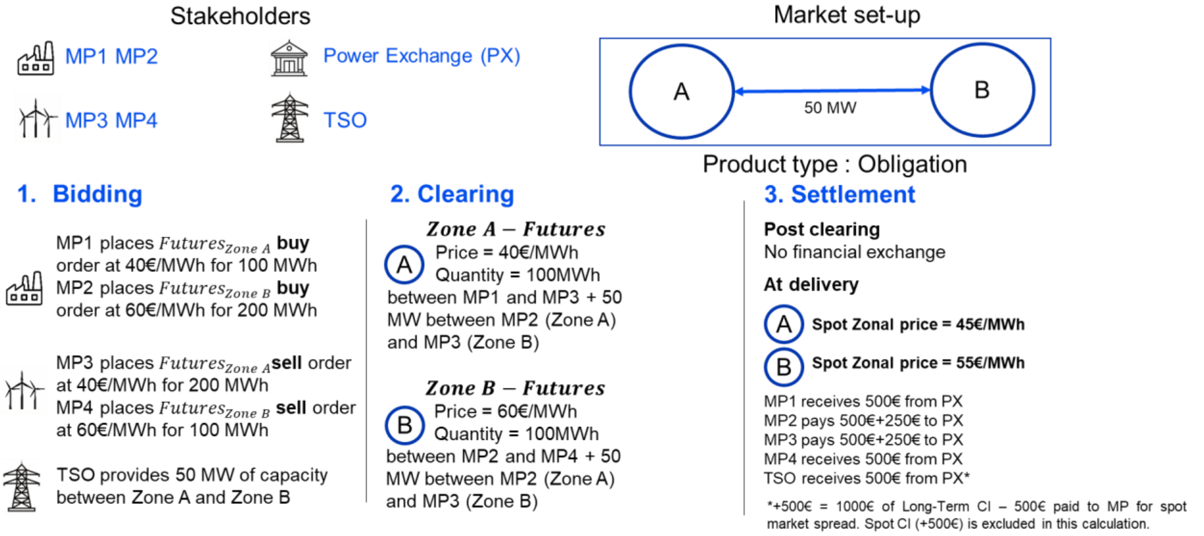
This arrangement involves both TSOs and PXs (NEMOs). In this set-up, the NEMO offers trading energy futures that can be matched across the border with a transmission capacity offered by the TSO. The bids of the market participants will be selected in order to maximize the social welfare of the auction while respecting the cross-zonal capacities provided by the TSO.

Financial flows of the market participants are computed as a difference between the obligation arising from matched futures prices and obligations arising at delivery i.e. zonal spot prices (negative value indicate pay for buy orders):

$$Amount\ to\ pay/receive = Futures\ Volume\ * (Zonal\ Spot\ Price - Matched\ Futures\ Price)$$

The congestion income of the TSOs is computed as a difference between congestion income TSOs receive in the long-term timeframe when matching and coupling the Futures and remuneration costs TSOs have to pay from the day-ahead congestion income (equivalent to LTTR remuneration) (negative value indicate negative income):

$$\begin{aligned}&Congestion\ income\ _{Zone\ A \Rightarrow Zone\ B}\\ &\quad = Interconnection\ capacity\\ &\quad * \big((Matched\ Futures\ Price_{Zone\ B} - Matched\ Futures\ Price_{Zone\ A})\\ &\quad - (Spot\ Price\ Zone\ B - Spot\ Price\ Zone\ \ A)\big)\end{aligned}$$



In the above example, the TSO receives as long-term congestion income resulting from forward market coupling the difference in clearing price of the zonal futures in both zones multiplied by the provided capacity $(50 * (60 - 40) = 1000€)$ and at the delivery has to remunerate the difference in spot clearing price of the two zones multiplied by the provided capacity $(50 * (55 - 45) = 500€)$ to PXs and MPs due to the reallocation of long-term cross-zonal capacity. The TSO therefore has a positive net congestion income because the long-term market spread was higher than the day-ahead market spread.