ENTSO-E Policy Paper

EU's Electricity Forward Markets

December 2022

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 39 member TSOs, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the interconnected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources.

ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with **climate objectives** and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility.**

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with **transparency** and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its legally mandated tasks, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

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1 Executive Summary

Long-term markets are envisaged to play a key role in helping achieve the EU's Green Deal ambitious objectives. Increased price volatility in the electricity system, due to the acceleration of renewable energy source (RES) deployment and exceptional geopolitical circumstances, is accelerating the focus on these markets to help market participants manage their risks.

Having received less attention in the past few years compared to the day-ahead and intraday markets, the long-term markets now face several challenges, including a lack of liquidity. These challenges are highlighted by the fast adoption of low-carbon generation, which will increase the need for hedging opportunities due to the expected growing price volatility in the years ahead.

ENTSO-E considers that the changes in market fundamentals require a reconsideration of the current design of long-term markets to make them fit-for-purpose and to ensure the better protection of market participants, retail suppliers and consumers.

The necessity to review the current long-term market models appears to be acknowledged by other key players beyond the Transmission System Operator (TSO) community such as regulators and policy makers. In particular, ACER and CEER published a draft policy paper on the 'Further development of the EU Electricity forward market' in July 2022, striving to find alternative forward market models. ENTSO-E's and ACER's assessments agree on the importance of finding solutions to the current challenges of the forward markets (i. e. low liquidity, undervaluation of long-term transmission rights [LTTRs], etc.) through improved hedging instruments or market models.

It is in this context that the TSOs, key players in the facilitation of electricity long-term markets, are exploring the current state of these markets, particularly considering four main aspects:

1. **Meeting the demand of increased hedging due to greater RES penetration;**
2. **Increasing the liquidity in illiquid forward markets;**
3. **The interests of end consumers; and**
4. **The risks of capacity calculation in the long-term timeframe.**

In the first part of the paper, ENTSO-E assesses the current forward markets from a comprehensive perspective and provides additional insights from the TSOs' experiences. In what follows, ENTSO-E provides initial analysis and views on two alternative Policy Options:

1. **TSOs as providers of hedging opportunities.** Policy Option 1 considers that market participants are used to LTTRs issued by TSOs which grant access to the liquidity of neighbouring forward markets. Some general considerations are proposed, for instance amending the allocation framework, ensuring volume adequacy, introducing a minimum auction price or terminating the current mechanism to ensure revenue adequacy (long-term allocated capacity [LTA] inclusion). Furthermore, two approaches are described which differ in the allocated products. In the first approach, (Approach 1), ENTSO-E proposes to continue issuing Financial Transmission Right (FTR) Options with some adjustments, and in the second approach (Approach 2), it is proposed to introduce FTR Obligations appropriate to the forward and future products traded in Power Exchanges.

2. **Purely financial forward markets.** Policy Option 2 constitutes a completely new approach, (Approach 3) that questions the economic efficiency of the LTTR market. It is supposed that the long-term market could evolve without TSOs, and hedging products for the future will be developed based on need by other market operators. Terminating the LTTR market is expected to reduce the complexity of the overall forward market, increase its flexibility and support the formation of correct long-term electricity prices.

The evaluation of the three main approaches shows that all of them will solve some of the observed challenges. However, at the same time, all approaches have drawbacks and come with a shift of risks between TSOs, market participants and end-consumers. The proposed approaches and improvements shall be further developed and assessed to ensure a deeper understanding of their implications for all stakeholders.

Moreover, further questions and insights on key topics such as the scope of implementation, the design of secondary markets or the design of particular products will be discussed in the next steps. In particular, the significant differences in the maturity of local forward markets will need to be considered in further assessments.

Therefore, ENTSO-E expects this paper to serve as a baseline for the ongoing policy debates to reform the electricity market and will continue investigating the described improvements. In doing so, ENTSO-E will contribute with valuable inputs in the upcoming discussions with policy makers and regulators about how the future forward electricity market can best be organised.

2 Introduction

Due to the lack of storability of electricity generation, electricity spot prices are highly volatile, resulting in severe risk for generators and consumers trading in the power market. Therefore, either long-term or forward, electricity markets have been established to allow market participants to hedge against the volatility of spot prices.

The long-term market model in Europe comprises:

- **Commercial markets for forward/futures products on electricity (whether traded in power exchanges or as bilateral deals or over-the-counter [OTC]); and**
- **Markets for LTTRs between bidding zones (BZs) offered by the TSOs.**

Other long-term instruments are also available in specific regions such as the Electricity Price Area Differentials (EPADs) in the Nordic and Baltic regions. An overview of the design of the current forward markets is further described in Annex 1.

The difference between forward and future contracts relates mainly to their level of standardisation, the manner in which they are traded and their guaranteed execution. The electricity futures markets are regulated by the European financial market regulation that covers derivatives trading and is not specifically related to energy markets. Financial market regulation sets capital, organisational and transparency requirements for participants in the markets for commodity derivatives (MiFID II[1] and MiFIR[2]), as well as requirements for counterparties that enter derivative contracts (EMIR[3]).

The electricity transmission rights market is regulated by the Forward Capacity Allocation Regulation[4] (in the following: 'FCA Regulation'), which establishes the rules for capacity calculation and allocation and defines different options for cross-zonal risk hedging. These hedging options play an important role in allowing market participants to secure capacity on cross border lines in advance. Overall, the FCA Regulation governs the relevant activities of TSOs, national regulatory authorities (NRAs) and ACER.

Challenges to the current market model are posed by the energy transition. The increased penetration of RES will increase the volatility of spot market prices and the current market structure, which is based on baseload products, does not meet the risk profile of intermittent RES-generation. Both are expected to increase market participants' needs for long-term hedges, which can currently be addressed only partially by the markets. Within this context, ENTSO-E commissioned a study[5] to assess alternative long-term market models in Europe. The results of this study are partly used in this document.

In addition, in July 2022, ACER and CEER launched a public consultation on their draft policy paper on the 'Further development of the EU Electricity forward market'[6]. Within this paper, several shortcomings of the current market design were identified, and potential mitigation measures were developed. However, in the opinion of ENTSO-E, the ACER and CEER policy paper fails to adopt a holistic approach and instead concentrates only on the redesign of the LTTR market. For this reason, ENTSO-E has developed 'ENTSO-E's Policy Paper on forward markets' with the intention of further evaluating different models for the future electricity forward markets in Europe, focusing on hedging opportunities for price risks.

1 Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU.

2 Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012.

3 Regulation (EU) No 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories.

4 Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

5 Internal study commissioned to DFC Economics in July 2022 to assess alternative long-term market models in Europe. The results of this study are partly used in this document.

6 ACER and CEER draft policy paper on the further development of the EU electricity forward market, 1 June 2022, available here.

Therefore, this document aims to contribute to the discussions on forward markets triggered by ACER, as well as to the ongoing policy debate on how to reform the design of European electricity markets by providing additional details about the long-term timeframe. The Policy Paper provides a thorough overview of forward markets detailing the LTTR and the EPAD models, but it also offers additional insights on power forward markets and OTC trading as key aspects to the holistic evaluation of the forward markets in Europe. It also contributes to the assessment of the challenges of the current forward markets, presenting additional evidence regarding them.

This Policy Paper is structured as follows: Section 3 presents the key considerations that are examined. Section 4 discusses the issues of the current European forward market design. Section 5 explores the proposed Policy Options (and approaches) for the future forward markets, and Section 6 evaluates the respective alternatives. Annex 1 provides a detailed overview of the current long-term markets. Annex 2 examines the application of financial market regulation to TSOs. Annex 3 provides a summary of the evaluation of the proposed approaches.

3 Key Considerations

ENTSO-E took into account the following key considerations when developing the Policy Options for a holistic approach:

- **Meeting the demand of increased hedging due to greater RES penetration.** To reach the ambitious climate goals of Europe's Green Deal[7] by 2050, a significant increase in electricity produced from RES is needed. As the amount of electricity produced from RES depends on the weather conditions and is thus highly volatile, the result will be strongly fluctuating day-ahead prices. Market participants will have an increased need to hedge against such varying prices. The future forward electricity market design needs to provide sufficient hedging opportunities. In addition, it should offer a wide range of flexible products that consider volatile generation profiles.
- **Increase the liquidity in illiquid forward markets.** The current forward markets in Europe have very different levels of liquidity. Although there are a few highly liquid markets, most of the BZs are illiquid.[8] Hedging only works when there is a certain level of liquidity in the markets. Consequently, it is necessary to increase the liquidity in illiquid forward markets.
- **Considering the interests of end consumers.** Looking at the current setup, TSOs provide LTTRs at most borders as an option for market participants to hedge against the volatility of the price spreads in the spot market at BZ borders. Hedging opportunities help market participants to reduce their price risk in the future, which can be beneficial for end consumers (e. g. via contracts with long-term price guaranty). Nevertheless, LTTRs are financed by TSOs' congestion income which TSOs can otherwise use for network improvement, the financing of redispatching measures and the reduction of network tariffs, all of which can also have a beneficial impact on the costs of end consumers. With that in mind, the analysis of the measures needed to increase liquidity in forward markets must aim at a cost-efficient approach, whereby the most beneficial outcome for end consumers is the objective. To reach this objective, the reasons for illiquidity shall be carefully analysed and possible solutions should also be considered outside of the TSOs' ambit.
- **Considering the risks of capacity calculation in the long-term timeframe.** In the current forward market design, TSOs perform long-term capacity calculation. It needs to be considered that capacity calculation in longer timeframes poses huge financial risks for the TSOs at the expense of end consumers. In particular, when contemplating expanding the timeframe for offering LTTR, the benefits and risks should be carefully considered. In addition, it would be of the utmost importance that TSOs have full and timely regulatory comfort with respect to the underlying financial risk. However, TSOs acknowledge that information regarding the amount of capacity expected is of interest for market participants.

7 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions Empty – 'Fit for 55': delivering the EU's 2030 Climate Target on the way to climate neutrality (14 July 2021)

8 See sub-section 4.1 for more details.

4 Issues in the current Market Design

In principle, well developed and liquid electricity forward markets in all European BZs would suffice to provide effective and efficient hedging opportunities to market participants. With sufficiently liquid forward markets in all BZs, market participants could obtain effective and efficient hedges against the volatility of the spot prices in any BZ simply by entering a transaction for the corresponding forward market.

However, given their limited sizes, most national markets are not sufficiently liquid. As forward products lack liquidity, hedging opportunities come at a high cost (for instance, due to large bid-ask spreads), or participants may altogether fail to find a counterparty willing to enter a transaction for a future covering a delivery period distant in time (in most markets, liquidity focuses on the next year of delivery).

More generally, LTTR markets and, to an extent, forward markets as a whole, currently fail to achieve their fundamental objective of providing effective and efficient hedging opportunities as they suffer from the shortcomings outlined in the following sub-sections.

4.1 Adequate liquidity and importance of liquidity

One goal of the FCA Regulation is to provide hedging opportunities for market participants by means of access to liquidity. Hedging provides a tool for traders and investors to mitigate market risk and volatility and thus usually minimises the risk of loss by reducing potential profits.

If there is insufficient liquidity in a given market, both price reliability and ability to hedge at all could be at risk. The liquidity of a market impacts the overall costs for hedging. These can be measured by the Bid-Ask-Spread that need to be paid by a market participant willing to enter a transaction. The Bid-Ask-Spread varies between around 0.1 to 0.5 €/MWh depending on the regional markets.[9]

The liquidity in the power markets is usually measured via Churn factors (which are defined as the traded volume divided by the demand of country). Figure 1 illustrates a fairly heterogeneous situation due to different BZ sizes and market concentration. The churn factor varies from around 8 for the German BZ to around 0.15 for the Hungarian BZ.

As liquidity is concentrated in a few commodity markets, also corresponding to ones with the larger sizes (Germany, Nordic, France, Italy and Spain being the most liquid and developed), participants seeking hedging opportunities in other BZs are either:

1. unable to hedge, for instance because they cannot enter a transaction for a future with a sufficiently distant maturity (leading to the issue of ineffectiveness), or

2. implement hedges inefficiently as they access markets where price discovery activity is insufficient.

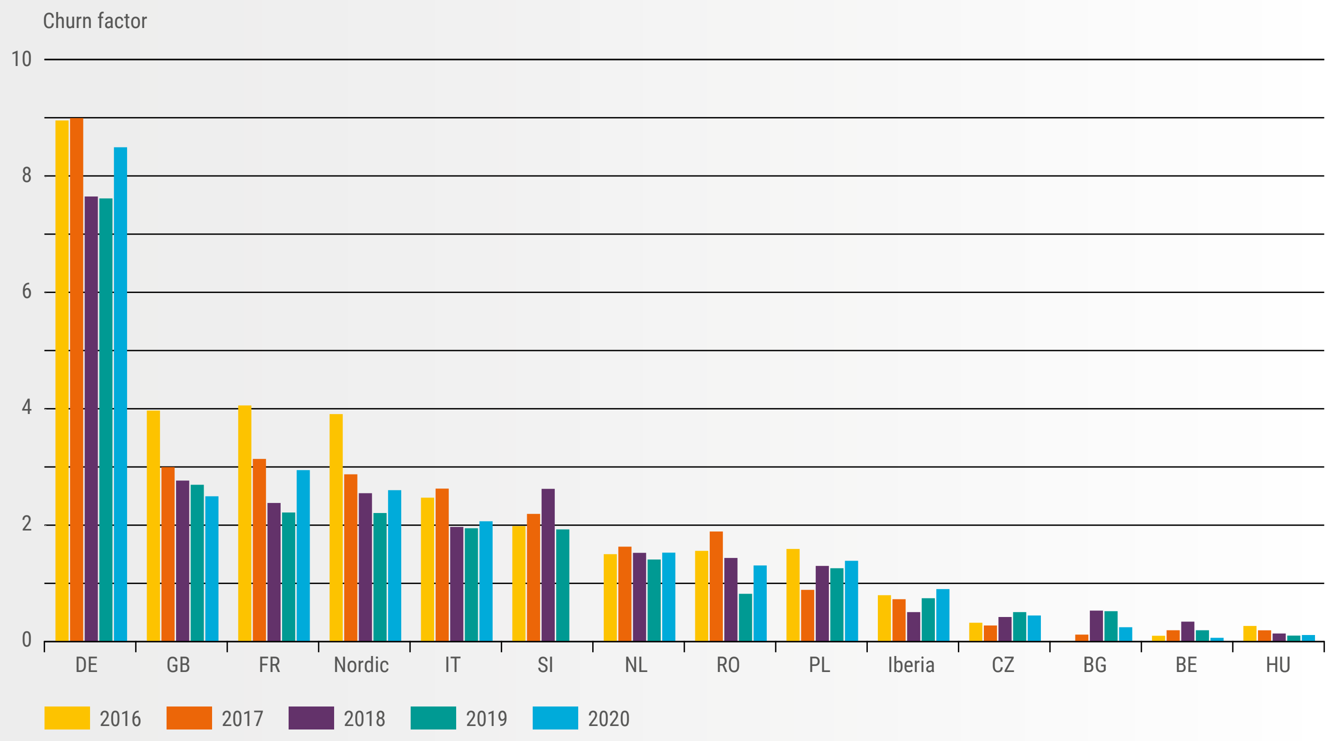


Figure 1 – Churn factors in major European forward markets (2016–2020); Source: ACER Market Monitoring Report 2020

For instance, low market activity translates into large bid-ask spreads, increasing the cost of hedging, and low churn factors, limiting the ability to adjust the hedge through time.

The current energy crisis is rewarding consumers who have hedged in the past. Hedging is now more than ever necessary due to the high volatility of spot prices. As the crisis and higher price levels are now lasting, this could impact liquidity in the longer term.

9 ACER Market Monitoring Report 2020

4.2 The LTTR undervaluation

ACER and CEER have already highlighted the issue of LTTR undervaluation in their draft policy paper. In addition, ENTSO-E has performed a thorough analysis of the state of the Pan-European LTTR market operated by the Joint Allocation Office (JAO). A key finding is the structural undervaluation of LTTRs on most borders, where the price of capacity in long-term markets is generally significantly lower than in day-ahead. This results in a financial swap from TSOs' congestion income (CI) towards winning market participants owning capacity rights. This represents a financial loss for end consumers because in most countries, this gap has to be compensated for by end consumers via their network tariffs.

Figure 2 shows the evolution of the CI reduction for all TSOs for the period 2019 to 2022, split by yearly and monthly products. A positive value represents an undervaluation of the LTTR by the market, leading to profit redistribution towards the LTTR capacity owners. For instance, in 2021 the total undervaluation (i. e. for both yearly and monthly products) was around 1.1 b€, which represented more than 25 % of the whole CI collected during the year of the same TSOs issuing LTTRs. For 2022, the total forecasted value of 'CI Loss' due to LTTRs is 2.6 b€[10].

On the other hand, the market (if competitive) should be offering lower prices and more price stability to consumers due to these additional earnings, yet the size of this benefit is rather unclear. The final impact on consumers, for both costs of LTTRs and benefits due to price stability, requires further careful consideration when reshaping the forward market.

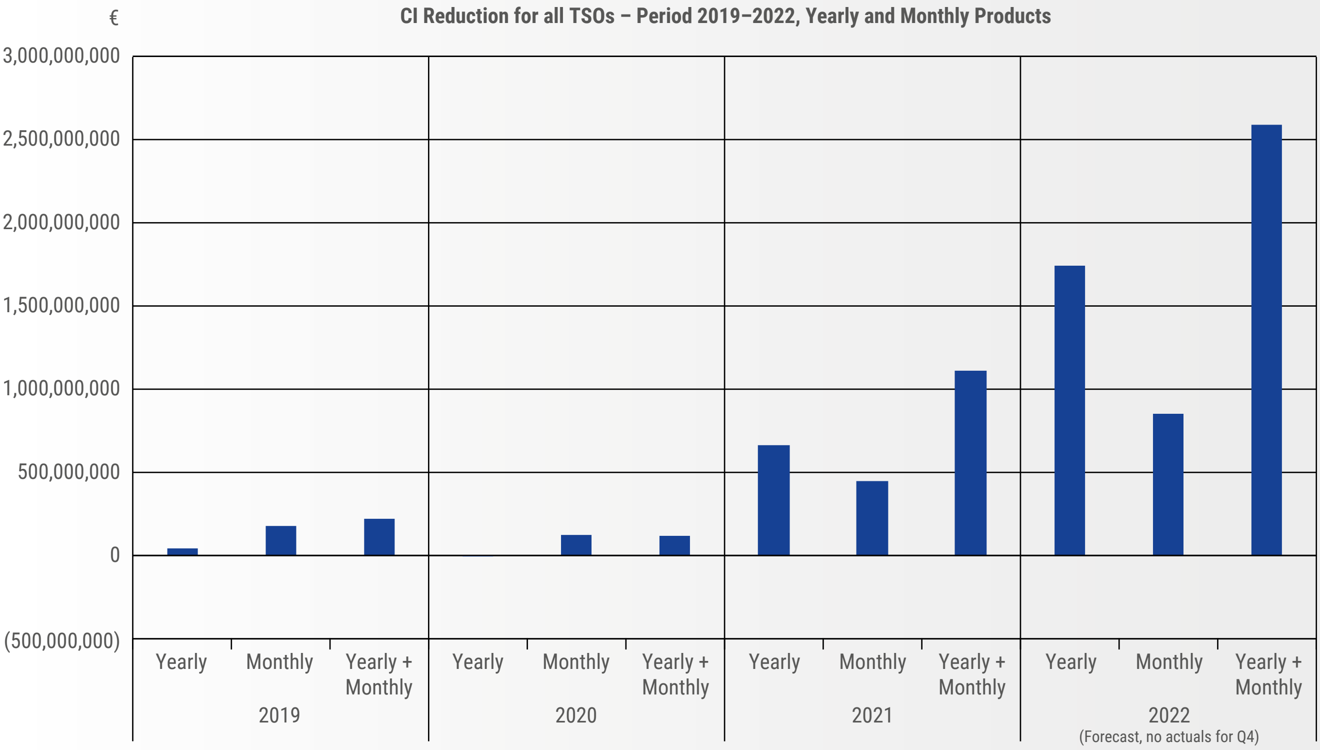


Figure 2 – 2019–2022 Financial swap from TSO's CI towards Market Participants[11]

ENTSO-E expects that the structural undervaluation of LTTRs would be more pronounced should multi-yearly products be introduced as proposed in the ACER and CEER draft policy paper. Indeed, the further ahead the delivery of the product is compared to its auctioning or trading, the more conservative the bids of the traders will be to reflect the increasing uncertainty over time. In addition, the capacity calculation for multi-yearly products lacks certainty due to the long-time horizons, which includes the risk of additional costs for end consumers due to additional redispatch. That is in addition to the increase of undervaluation which end consumers also finance.

10 Only DA prices actuals and related monthly LTTRs auctions for the period 01.01.2022-30.09.2022 were considered. The underlying assumption is that the average spread and average specific results observed in the period 2022 Q1+Q2+Q3 will be the same for Q4 2022. A recalculation of these values with more accurate data will occur in early 2023, once DA actuals for the whole year and all monthly auctions results are available.

11 I. e. Potential additional Day-Ahead CI (if capacity would have been offered to DA) minus LT CI collected.

In addition to the price situation due to the overall energy crisis, the main potential explanation for this systematic undervaluation in the observed time period is that TSOs are price takers. Indeed, TSOs will supply to market participants the capacity at any price higher or equal to zero, regardless of the actual value of the capacity. In the event of insufficient liquidity for a specific border, market participants are incentivised to bid conservatively and thereby increase their profit.

In addition, over the last few years, TSOs have been stressing to ACER the additional extraordinary cost to society related to the issue of LTTRs: the remuneration of LTTRs' holders in case of a decoupling event (of the day-ahead market coupling). The question of whether a few market participants shall benefit from an unjustifiable overcompensation to the detriment of the tariff payers has yet to be addressed. The TSOs have already addressed the matter and included a request to amend the FCA GL accordingly in their latest response to the EC stakeholder CACM 2.0 consultation.[12] (See also section 4.6).

4.3 Current secondary market of LTTRs

There currently exist two different options as defined by the Harmonised Allocation Rules[13] for offering LTTRs in a secondary market. The options are:

1. Transfer capacity to another market participant; and
2. Return the allocated capacity in a subsequent auction.

As a market participant willing to buy LTTRs on a secondary market, the only option is to approach an existing LTTR holder and express your willingness to buy and arrange a transaction bilaterally. To facilitate this possibility, JAO publishes the list of LTTR holders who won capacity at a long-term auction and additionally offers a notice board where LTTR holders can publish their willingness to sell and market participants can publish their interest in buying LTTRs. So far, this opportunity has been rarely used by market participants.

However, due to MiFID II limitations regarding the organisation of a secondary market, JAO cannot further facilitate the continuous trading of LTTRs on a secondary market without falling under financial regulation, which would result in additional reporting obligations for JAO as well as for market participants. The application of financial regulations to TSOs is further described in Annex 2.

Regarding the returning of LTTRs to a subsequent auction, although this option is used by some LTTR holders, many market participants prefer to benefit from the LTTR remuneration based on the day-ahead market spread, especially considering the negative risk premium currently paid for LTTRs. In addition, most BZ borders only offer a single auction per month to return their annual LTTRs. The returned LTTRs are offered in addition to the capacity offered by the TSOs. During the monthly auctions between 2019 and 2021, only 2 % of the offered capacity stemmed from returned yearly LTTRs[14].

Market participants may expect to have more opportunities to buy and sell LTTRs on an organised secondary market, allowing them to acquire LTTRs outside of the normally scheduled long-term auctions.

4.4 Collateral requirements

Whenever market participants wish to be active on a trading platform, they need to deposit collaterals to limit the risks of the trading platforms. Currently, there are no harmonised requirements for collaterals. In addition, market participants need to provide collaterals for each platform, which can add up to a high amount considering the increased spot prices. Furthermore, in some cases such as the Nordic futures/forward markets, the recent introduction of financial regulation (i. e. MiFID II and EMIR) has entailed such an additional burden on market participants that it has resulted in a switch towards bilateral trading (i. e. OTC), reducing the overall participation and liquidity on the markets.

Consequently, collaterals can represent one of the main entry barriers for market participants, as well as one of the main reasons for them leaving a particular market. The following sub-sections give an overview of the current collateral systems for futures/forward electricity products and their problems.

12 See All TSOs' answer to question 24 of the European Commission public consultation on the revision of the Capacity Allocation and Congestion Management Regulation

13 In accordance with the principles of Article 51 of Regulation (EU) 2016/1719.

14 Considering only FCA regulated borders.

4.4.1 Collateral system of LTTRs

Collaterals are used to ensure that both bids placed and the resulting allocated capacity can be paid for by the respective market participant. There are currently two options for providing collaterals at JAO:

1. Cash deposit on a dedicated business account, or
2. Bank guarantee issued by a bank meeting the defined criteria.

On the one hand, the benefits of having collaterals are the following:

- reduction of the risk of market manipulation and gaming;
- minimisation of the speculation risk, i. e. reduction of unpaid bids that could cause misleading price signals.

On the other hand, collaterals can be costly as they need to be made available prior to an auction, which can be well in advance of the delivery period of the auction. Annual auction amounts are significant and, therefore, efforts have been made in the past to reduce the collateral requirements to only a month or two of the whole annual products.

4.4.2 Collateral system of Nasdaq, the main marketplace for EPADs and System Futures (hub price)

Currently, the hedging product for the Nordic power market, such as System price futures and EPADs, are mainly traded on the Nasdaq exchange[15]. The System price futures and EPADs, as well as those contracts traded via brokers, are cleared using Nasdaq Clearing. The System price futures traded on EEX are cleared according to EEX routine, i. e. via the usage of ECC and/or of a clearing bank. Clearing contracts on Nasdaq is done in different ways but the two main differences is that the process is done either as being a clearing member or via a clearing member. If clearing is done via a clearing member, the party can trade on the exchange as an exchange member.

In this case, the collaterals are managed by the direct member that this party has an agreement with. Collaterals and margin requirements and management[16] is done in accordance with the relevant financial regulations (MiFID II, EMIR etc.) requiring both base collaterals and daily margins.

To manage the continuity of the clearing house, there are several schemes[17] in place, mainly introducing a community fund that all members contribute to, and there are also back-up member agreements to enable a member to port its positions and collaterals to another member.

4.4.3 Collateral system of commodity markets

Joining an exchange requires market participants to deposit a collateral with a central counterparty. Depending on the exchange, the collateral type is cash, bonds, bank guarantees or emission allowances. The sharp increase in electricity prices in 2022 translated into much higher collateral requirements being imposed on market participants. Indeed, the amount of collateral that market participants need to provide is usually linked via mathematical formulas to the following parameters:

- Historic and forecasted volatility of the market prices;
- Mark-to-market[18] open positions (which are subject to margin calls in case of market price moves against the positions i. e. in case the collateral is not sufficient any more); and
- Volume of allowed exposure of a market participant (i. e. bid quantity in MW that a market party is allowed to place on the trading platform).

The high upfront costs for market participants to participate in the different forward markets (whether for LTTRs, EPADs or commodity markets) act as one of the main entry barriers for new market participants, but also as an incentive to market participants to look for alternative hedging products (i. e. OTC markets).

15 EEX also lists System price Futures for the Nordics but not EPADS.

16 For more information see here.

17 For more information see here.

18 Mark-to-market involves recording the value of the collaterals to reflect the current market value.

4.5 Complexity of hedging between not neighbouring bidding zones

In a multi-zonal power market as of today, hedging of price-volatility using the current instruments of zone-to-zone FTR Options[19] and Contract for Difference (CfD) are particularly difficult. As will be discussed further, the reasons are three-fold:

A zone-to-zone FTR Option does not provide a complete hedge against price volatility.

To illustrate the first point, let us imagine a simple example with two BZs connected by an interconnector. A generator located in zone A has obtained a future in zone B, and buys an FTR Option to cover for the volatility of the price difference between zone A and zone B. Their expected pay-out for this position is:

$$Expected\ payout = P^A + (P^B - P^A) + (\widehat{PB} - P^B)$$

P^A = Power price in zone A

P^B = Power price in zone B

$\widehat{PB}$ = Contracted price in zone B

$(P^B - P^A)$ = Pay out of the FTR Option A→B

$(\widehat{PB} - P^B)$ = Pay out for the future in B

If the price difference between A and B turns out to be in the positive direction for the generator in A ($P^B > P^A$) the final pay-out for A is simply $\widehat{PB}$, the contracted price in B.

However, as an FTR Option is the current instrument in most of Europe, the pay-out from the FTR itself will be zero if $P^B < P^A$. In this case, the final pay-out from the position of the generator will be $(P^A - P^B) + \widehat{PB}$ (which is larger than $\widehat{PB}$). This means that the expected pay-out to the generator's position is:

$$Expected\ payout = \in \{\widehat{PB}\ ,\ (P^A - P^B) + \widehat{PB}\ \}$$

Hedging with the combination of a future (or a physical position) in a foreign BZ and an FTR Option leaves the generator with an unknown pay-out at a level above the minimum of the contracted price in the foreign BZ. If we also consider the auction price paid for the FTR Option (A → B), the final value of the hedge could turn out below the contracted price in B.

Several zone-to-zone FTRs are required to hedge between not neighbouring BZs.

When looking at a multi-zonal setup, a generator (or consumer) might not find a suitable hedge in his native BZ, or even in a nearby adjacent BZ. Due to many BZs with low liquidity, market participants have difficulties obtaining a 'reasonable' priced hedge in the commercial market for the native BZ.

Thus, we could imagine that a generator in Slovakia (SK) finds a suitable hedge in the more liquid forward market in Germany (DE). To complete such a hedge, the generator will now also need several FTR Options to cover for the price spread volatility between adjacent BZs, closing the gap from SK to DE. There are different paths to choose for the hedging generator, which constitutes a complicated picture for it.

Considering that each FTR Option along the path might provide either a positive or a zero pay-out, and will come at a certain cost at the LTTR auction, this will result in a very complicated pay-out and thus hedging-situation for the generator.

19 PTRs are neglectable as they have the same effect as FTR options if not nominated.

Hedging between not neighbouring BZs with heterogeneous solutions.

In the example above, the mentioned market participants are part of the region where the same instrument for cross-border hedging is used. In the case of market participants being located in areas with different regimes, the complexity increases.

Considering a generator in the Northern BZ of Norway (NO4) finding a hedge in the DE market, the generator is located in the area where EPADs are used to hedge price differences with a system price, whereas at the German borders FTR Options are used. Figure 3 illustrates the explained issue.

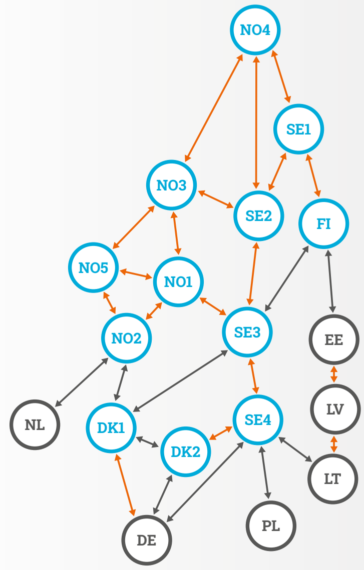


Figure 3 – Complexity of hedging between not neighbouring BZs

4.6 Costs on ensuring firmness

TSOs receive long-term congestion income, which is the amount market participants pay for LTTRs distributed by the principles defined in the FCA Regulation and the details defined in the respective methodology[20]. In return, TSOs pay market participants the price difference of the day-ahead prices for the capacity purchased[21] in line with the FRC methodology and the Harmonised Allocation Rules. In that sense, LTTRs are fully firm for holders, which means that they get the pay-out of the price difference in (nearly) all cases. That means that for TSOs, that they are obliged to curtail LTTRs if they cannot provide the long-term allocated capacities in the day-ahead timeframe. The holders of curtailed LTTRs get a compensation payment of the price spread in the day-ahead timeframe. That could lead to extraordinarily high payments by TSOs in cases of decoupling (where very high price spreads occur) or unplanned outages of interconnectors at borders (as consequently the price spreads increase in those cases) without any direct income to settle these payments. For instance, the decoupling incident on 8 June 2019 lead to a significant payment of 19 million € to LTTRs holders by the respective TSOs.

Considering LTTRs to be auctioned off two or three years ahead, the uncertainty and the financial risk increase further as the physical fulfilment gets more uncertain (e. g. the floods in Germany in 2021, which also caused damage on transmission lines). These expenses are partly or fully paid by end consumers via their network tariffs.

In the following part, some different solutions are discussed to reduce the risk TSOs take by giving out LTTRs.

One method to completely reduce the risk TSOs and end consumers are exposed to is the abandonment of LTTRs (as presented in Policy Option 2). In that case, TSOs would not receive long-term congestion income and would not pay the price spread of the day-ahead timeframe anymore. This solution would also solve the issue of undervaluation.

The risk for TSOs could alternatively be reduced by a reduction of firmness. In pre-defined incidences such as decoupling and other unpredictable events, TSOs would not be obliged to pay the price spread of the day-ahead timeframe but instead the price originally paid for the LTTRs possibly with a fixed small amount on top of the compensation for the efforts.

In their draft position paper, ACER and CEER present another option in the event of decoupling. Instead of the market spread, the congestion income collected via the fallback explicit auction should be paid to market participants. ACER and CEER argue that this way, market participants have an incentive to participate in fallback explicit auctions, which is not currently the case. TSOs welcome this measure and ask for its swift implementation.

It is argued that the reduction of firmness will lead to market participants offering lower payments and would increase

20 In accordance with the principles of Article 57 of Regulation (EU) 2016/1719.

21 In accordance with the principles of Article 61 of Regulation (EU) 2016/1719.

the undervaluation of LTTRs. However, this effect will also depend on the cases where firmness is reduced. If they are only extremely rare and unpredictable, the effect on the offers for LTTRs and undervaluation is most likely very limited.

Another option could be that firmness remains ensured for market participants but other measures in addition to the congestion income of TSOs are used to cover the financial risk in pre-defined incidences such as decoupling or other unpredictable events. Another measure could be that costs occurring in those cases are covered by a special reimbursement system by the respective NRAs. Those other measures would increase the financial burden on end consumers and should only be chosen after a cost–benefit analysis of end consumers.

Depending on the configuration of such an option, TSOs are still exposed to risks as reimbursement might not happen immediately. In addition, the financial burden for end consumers might stay the same as the reimbursement is most likely covered by network tariffs.

In the event some sort of secondary market for LTTRs is implemented, one could argue that in some more predictable situations such as unplanned but long-term outages of interconnectors (e. g. the flood mentioned earlier), the respective TSOs could buy LTTRs back. By doing so, TSOs can reduce the capacity offered in the day-ahead timeframe (via LTA inclusion) and can reduce the LTTRs they have to pay the price spread to. The financial risk of immediate incidences such as decoupling could remain.

Firstly, the feasibility of this option shall be evaluated by legal experts as TSOs would enter the secondary market with an advantage towards other participants as they would have related knowledge (e. g. about an outage) that other market participant would not have. This might be classified as insider information and breach REMIT[22].

In addition, market participants might not offer their rights if TSOs attempt to buy back LTTRs in a secondary market as they might assume they get a higher payback due to a higher price spread in the day-ahead timeframe.

4.7 Current model not future proof for RES integration (price risk only and not volume risk)

In the past, energy delivery traded in forward timeframes was backed by dispatchable generation. Given the relative certainty that the specified volume could be delivered during either peak or baseload hours, it made sense to price products according to those two definitions. As RES take over increasing market share for electricity generation, it may seem of interest to switch to other models rather than delivering a specific constant amount of energy at peak/baseload price.

In particular, the market shows a seemingly exponential increase in Power Purchasing Agreements (PPAs) to finance new RES projects. These are generally OTC agreements established through direct negotiation between the RES supplier and the client consuming the electricity. As a result, a variety of different forms are developed depending on the needs of the supplier and client:

- Physical or virtual (i. e. purely financial) products;
- Fixed or floating prices;
- Time span (5–20 years); and
- Traded volume (as produced/as forecasted/profiled/baseload/etc.).

Given their success in financing new renewable projects, it would appear that PPAs are indeed an appealing hedging option for both RES generators (to have a secure source of income) and consumers (to have access to clean and cheaper energy). In looking for forward products to accommodate RES, PPAs should serve as an example and continue to be facilitated. There are some important barriers, such as:

- Complexity of aptly pricing/setting up a contract;
- Access to financing and covering collaterals; and
- Engagement for large volumes and long periods of time

Although this is not necessarily blocking to establish PPAs (particularly for large players such as big utilities and industrial consumers), these are possible areas to investigate when attempting to improve the facilitation of RES forward markets. As an example, the Spanish government – Spain being the country with the largest RES capacity under PPA in Europe[23] – provides insurance and guarantees for energy-intensive consumers willing to enter into a PPA. In addition, they include standardised PPAs that can serve as a model for concluding such agreements[24].

22 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency

23 Source

24 Source

In summary, it should be noted that much of the evolution for forward market opportunities regarding the RES generation is happening outside of the context of the more traditional futures/forward markets. In the examples listed above, ENTSO-E and the TSOs have less of a role to play, but policy makers should not overlook the importance of developing these areas going forward if the aim is to improve futures/forward markets and hedging opportunities for consumers. One important remaining factor more related to the matter discussed in this Policy Paper is the concept of cross-zonal PPAs and how the alternative forward market models from Section 5 could facilitate them.

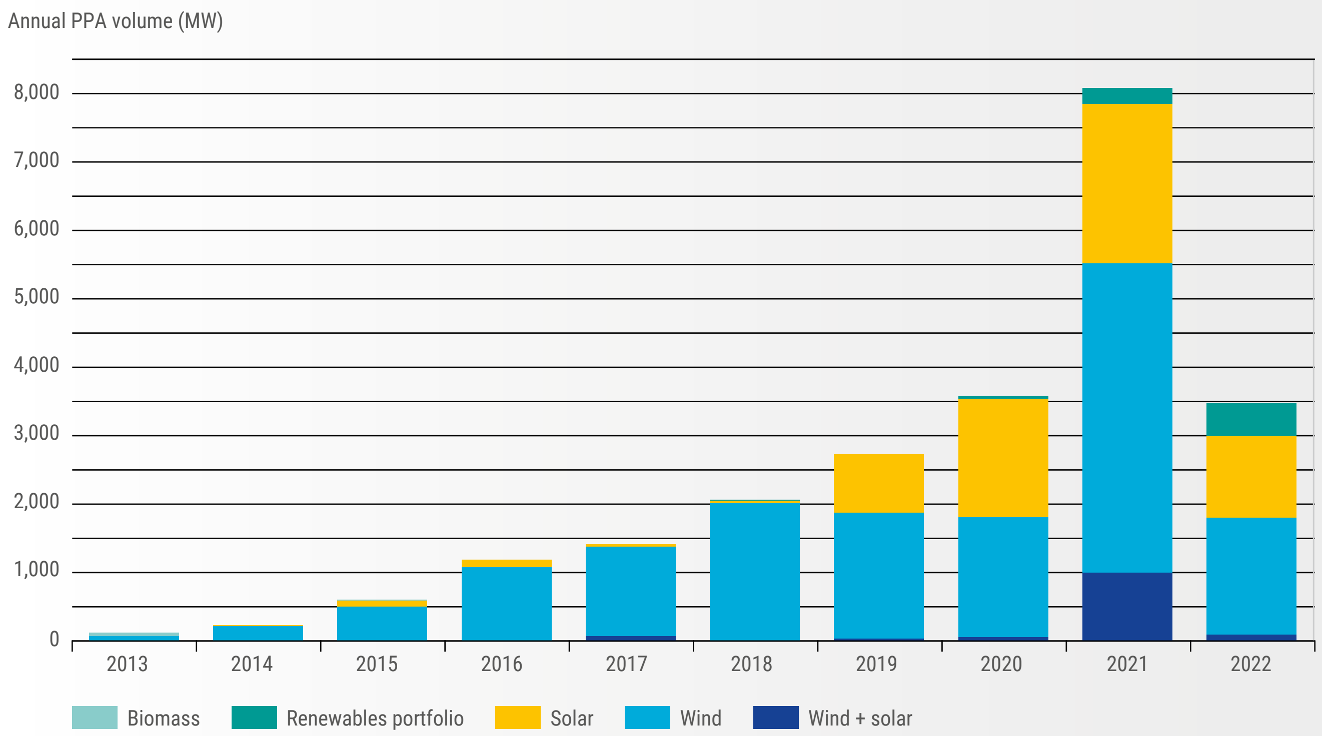
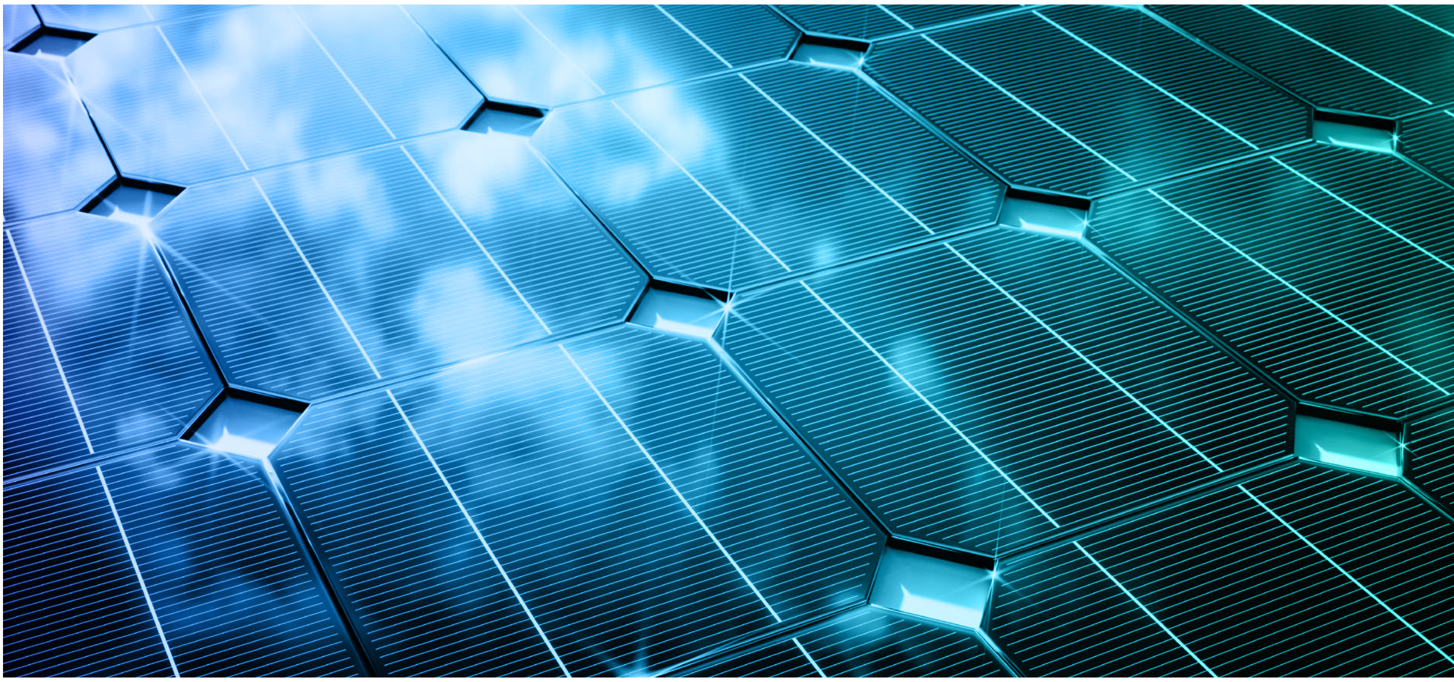


Figure 4 – Annually contracted RES PPA volume in Europe[25]



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4.7.1 Cross-zonal PPAs

The concept of an intra-zonal PPA is fairly easy to grasp as the physical energy can be directly allocated to the client within the same BZ whenever it is produced. The matter is different for cross-zonal PPAs as (on most BZ borders), it is not possible to allocate energy directly to a specific client, but rather exchanges are determined as a result of the market coupling. It is still possible, and in practice today, to allow fixed-price exchanges between generation and offtake through virtual PPAs. The latter presents a purely financial settlement under a CfD between supplier and client based on the spot prices (cf. Figure 5 for illustration).

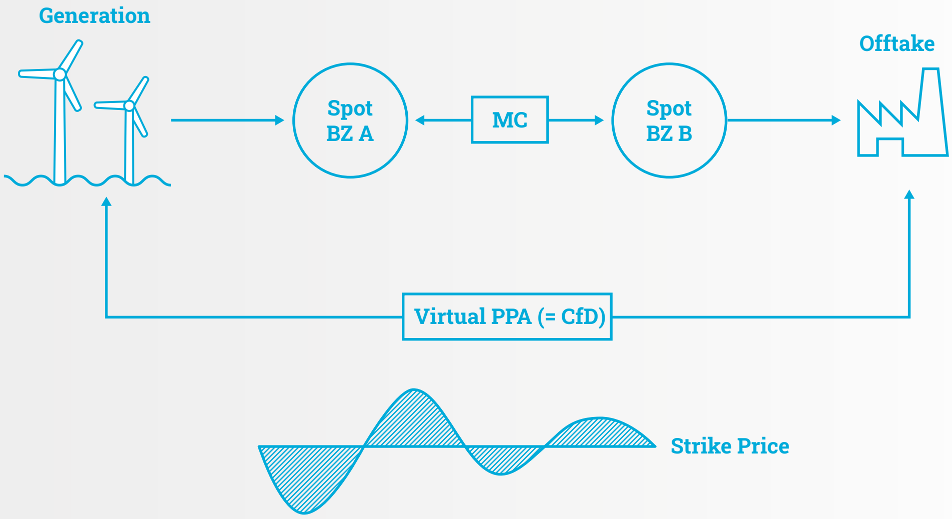

Figure 5 – Illustration of virtual cross-zonal PPA

The idea is that both parties are, under such a contract, able to buy on their local spot market and settle the difference with respect to the strike price in their CfD in a separate settlement. This is rather apparent when there is no congestion between the BZs as both parties bought/sold at the same price. However, when there is congestion, generation may have been sold at a low price, whereas the consumer bought at a high price. In that case, the CfD settlement comes at a net cost for one of the parties (depending on the modalities of the virtual PPA).

Ultimately, this effect should be incorporated in the strike price of the CfD. However, it illustrates that the risk of a market spread is important for these types of contracts. In that sense, there could be an interest for the cross-zonal hedging options discussed in this paper. The proposed improvements in the next section should also appeal to parties under cross-zonal PPA looking to hedge the spread between the two zones and provide more security on the offered strike price.

5 Forward Market Model Options

In the majority of Europe's countries, TSOs allocate LTTRs to offer hedging opportunities to the market. LTTRs are designed to be 'market participant-friendly' with low entry barriers ('market-friendly' collateral scheme, no trading fees, no reporting obligations according for financial regulations) compared to the trading of derivatives, as they are a complimentary product to secure a firm hedge.

As long as liquidity is brought into the forward markets using LTTRs, alternative solution will hardly evolve. For this reason, it comes as no surprise that liquidity of many markets of power derivatives is missing. The issue of liquidity, together with the six other challenges described before, represent the basis for developing the alternative Policy Options proposed in this section.

Accordingly, ENTSO-E sees two fundamental Policy Options that can be implemented:

› **Policy Option 1 – TSOs as providers of hedging opportunities.**
  TSOs shall provide hedging opportunities to the market by issuing LTTRs.

› **Policy Option 2 – Purely financial forward market.**
  TSOs are not providers of hedging opportunities and trust the functioning of the market.

The two Policy Options which unfold into three Approaches are explained in detail in the following sub-sections. An evaluation of the Approaches is included in Section 6.

5.1 Policy Option 1 (Approaches 1 and 2): TSOs as providers of hedging opportunities

In the proposed Policy Option 1, TSOs are and in many cases remain providers of hedging opportunities. As LTTRs are designed to have low entry barriers for market participants, they have become used to the fact that access to liquidity of neighbouring forward markets is provided by such products. For that reason, alternative hedging opportunities (e. g. futures/forwards) in the home BZs are and are likely to remain illiquid.

There are several alternatives to be explored, from adjustments to the current model based on FTR Options (Approach 1) to further LTTR improvements introducing FTR Obligations (Approach 2) and additional development of the products. The different approaches are assessed in the sub-sections below. Further developments and some general implications for zone-to-zone and zone-to-hub products, capacity calculation and allocation are outlined in sub-sections 5.1.3, 5.1.4 and 5.1.5, which apply to all LTTR products in general. In addition, sub-section 5.1.6 highlights the impact of the planned long-term flow-based allocation methodology on the capacity allocation.

5.1.1 Approach 1: FTR Options with adjustments

In the proposed Approach 1, FTR Options will remain the standard hedging product and will replace PTRs at all European borders. In addition to the current design, the following market design improvements will be applied:

- FTR Options shall be issued on a rolling basis. Auctions for their allocation should take place sufficiently ahead of each year, quarter and month for base load and peak load profiles.
- For the sake of adequacy between the FTR auction with the market needs (i. e. the electricity forward market), the volume offered to the auctions needs to be adjusted with the electricity forward market liquidity. Thus, each product (yearly, monthly, quarterly) shall be offered in several auctions as it takes time to absorb high volumes issued in one auction due to the low liquidity in the future market. Sub-section 5.1.5 give more insights on this topic.
- Establishment of a secondary market for FTR Options.
- Introduction of minimum prices. For each auction, a minimum price shall be defined which guarantees a minimum FTR value (see sub-section 5.1.5). The unsold capacity could be offered to the next auction. TSOs are assured not to sell the capacity at an undervalued price.
- Assessment of shortening the auction answer delay. Currently, the results of long-term auctions are published after 25 min. This time could be shortened as the long publication times could mean higher risks for market participants. Consequently, the willingness to pay for long-term products could improve. Furthermore, possibilities to arrange long-term auctions closer to the start of the delivery period are likely to be beneficial for market participants. Both options remain to be assessed by TSOs and JAO, also considering the implications of long-term flow-based allocation (see sub-section 5.1.6).
- The auction calendar will be defined in such a manner as to have the auctions scheduled at different times or even days for every border, in order to allow market participants to take part in all auctions. This would lead to more liquidity on different BZ borders.

The implementation of the proposed improvements would be subject to the investigations related to Long-Term Flow-Based Allocation (see sub-section 5.1.6).

With the implementation of the proposed adjustments, FTR Options would provide a fair hedging opportunity for market participants as it limits their financial risks to the FTR Option price only – instead, the financial risks remain at the TSOs on the expense of the end-consumer. Furthermore, the proposed adjustments could potentially improve, to a certain degree, the issues related to access to liquidity and to the secondary markets.

However, FTR Options would not completely remove the exposure of market participants to the volatility of their home bidding zone price as the volume of cross-border hedges is limited to the underlying capacity (no netting possible). Therefore, under Approach 2, FTR Obligations are further assessed as an alternative product.

5.1.2 Approach 2: FTR Obligations

In the proposed Approach 2, FTR Obligations will be the standard LTTRs, replacing FTR Options and PTRs at all European borders. The features of Approach 2 are described in the following:

- One of the characteristics of FTR Obligations is that those issued in opposite directions on the same bidding zone border can be netted out, in the sense that their payoffs during the delivery period are equal in absolute value and opposite in sign, and therefore they net themselves out. This means that, as long as they are balanced in volumes, FTR Obligations can be issued in unlimited quantities in excess of the physical capacities available in either of the two directions between the corresponding BZs. If interest for FTR Obligations of opposing directions net each other, it is more efficient if this trade happens at the secondary market as price formation at actions needs a limited offer (more on this in sub-section 5.1.5)
- FTR Obligations shall be offered at least for annual, quarterly and monthly delivery periods, for base load and peak load profiles. This is in line with the delivery periods typically traded in electricity (commodity) futures markets. Furthermore, yearly, monthly and quarterly products shall be issued in several auctions to ensure volume adequacy with the electricity forward market (see sub-section 5.1.5).
- A secondary market for FTR Obligations could be organised by entities other than the TSOs – e. g. financial exchanges or other organised marketplaces, based on continuous trading (the typical trading method for financial markets). Beyond the FTR Obligations issued by TSOs, additional FTR Obligations could be created in the secondary market by matching demand and supply, taking advantage of the netting properties of these instruments. Once issued, the FTRs Obligations allocated by the TSOs and those created in the secondary market would be indistinguishable. Moreover, if the FTR Obligations and the electricity futures were traded on the same platform, they could also be combined and recombined to match demand and supply of the different instruments, taking advantage of the equivalence of a combination of electricity futures and FTR Obligation. Furthermore, market participants only have to fulfil collateral requirements once. The idea of centralised trading is further discussed in Box 4 under sub-section 5.2.
- Introduction of minimum prices. For each auction, a minimum price shall be defined which guarantees a minimum FTR value (see sub-section 5.1.5). The unsold capacity could be offered to the next auction. TSOs are assured not to sell the capacity at an undervalued price.
- FTR Obligations allow for the creation of 'synthetic futures' which could be created via several methods. One method is by combing an electricity futures contract traded in a liquid electricity forward market with a FTR Obligation. Another method is by combing a standard electricity futures contract or CfD contract in adjacent BZs, dependent on current forward market structure. This would provide additional hedging opportunities in a BZ with a less liquid electricity forward market by linking it to an area with more liquidity. This is expanded in the paragraph below. Box 1 illustrates the principle of 'synthetic futures' and Box 2 describes an example of this.
- Once sufficient liquidity for the commodity forward products is also developed in former illiquid markets, the FTR Obligation price is determined simply by a non-arbitrage condition as the price difference between the futures products. The initial allocation of LTTRs via auctions might no longer be necessary, and TSOs might cease the allocation of long-term products via the auctions – retaining the 'traditional' role of collecting the 'spot' congestion rent and passing it on to consumers. See Policy Option 2.

The implementation of the proposed improvements would be subject to the investigations related to Long-Term Flow-Based Allocation (see sub-section 5.1.6).

The impact of switching from PTR/FTR Options to FTR Obligations is further assessed in the following sub-sections:

5.1.2.1 Amendment of collateral scheme

When switching from PTRs/FTR Options towards FTR Obligations, changes in the collateral scheme need to be considered. Due to the different nature of the payment flows incurring in the two products, switching to FTR Obligations would potentially require a higher collateral need and/or the introduction of a new mark-to-market collateral mechanism. Indeed, whereas for FTR Options there is a cap on the potential loss for the market party being the clearing price of the auction, there is no cap for the potential losses of a market participant in an FTR Obligation scheme.

5.1.2.2 Need for clearing house

Furthermore, due to the symmetric nature of FTR Obligations, TSOs (and consequently the end consumer) are at risk of unexpected losses if LTTR holders are unable to pay due to e. g. bankruptcy. This leads to an increased counterparty risk for TSOs that could be reduced by the introduction of a central clearing house, which the FCA Regulation and the Harmonised Allocation Rules already anticipate in the event of the allocation of FTR Obligations.

Depending on the chosen clearing house and its specifications, the clearing house will most likely not cover all risks, such as extreme cases like bankruptcy. In those cases, TSOs or JAO, and lastly end consumers, would have to bear the risk that a clearing house is not able to take. Consequently, this solution would lead to additional risk being covered by end consumers (via network tariffs) compared to the status quo. The formulation of minimal requirements for a clearing house or the creation of a separate default fund could, however, decrease the risk level taken by end consumers. If policy makers decide that additional risks shall be covered by end consumers, they shall aim at a harmonised process among the Member States by describing the mechanism of cost and risk coverage via network tariffs or alternative solutions in the respective regulation and shall include immediate cost coverage. For market participants, on the other hand, this solution would come at a certain cost (clearing fee).

5.1.2.3 Managing the counterparty risk

Under this Approach 2, FTR Obligations would be allocated through simultaneous auctions for both directions on all borders. This approach recognises the fact that FTR Obligations can be combined over different borders to provide hedging between different (non-contiguous) BZs. In fact, any path connecting any pair of BZs can be used to combine FTR Obligations issued on the different BZ borders along the path to provide hedging of the variability of the price differential between the pair of bidding zones. In those auctions, TSOs shall only be the counterparty for FTR Obligations in one direction at a border. It shall always be the direction that market participants enter the auction with the higher positive offer and only on the volume as resulting from capacity calculation.

In theory, market participants would always value an FTR Obligation in one direction as leading to a positive net pay-out and the other direction leading to a negative pay-out. For an FTR Obligation with a positive net pay-out, a market participant is willing to pay for in an auction, whereas a market participant would want to get paid for an FTR Obligation with a negative net pay-out. In a secondary market, those market participants with opposing interests can match without the support of TSOs/JAO.

If TSOs/JAO were the counterparty for all FTR Obligations in both directions for positive and negative prices, market participants would easily abuse this mechanism by entering the auction in both directions with a higher positive price for one direction than the negative price in the other direction. As those capacities would net, TSOs/JAO would be the counterparty for both and gain a loss without an underlying capacity, which would need to be covered by end consumers.

5.1.2.4 Creation of synthetic products

There are several possible designs of FTR Obligations and possibilities to create synthetic electricity futures by combing different types of contracts.

It is possible to create a ´synthetic´ electricity future by using an FTR Obligation and an electricity future contract. To provide additional hedging opportunities, the ´synthetic´ electricity future would be comprised of an electricity futures contract from a BZ with a liquid forward market and a FTR to a BZ with low liquidity. This would allow the market participants in the BZ with low liquidity to obtain a hedge against the area price with a contract. An example of this is illustrated in Box 1. How much it supports or even hampers the increase in liquidity in the area with low liquidity is uncertain. However, it is likely that market participants utilizing the illiquid BZ would probably switch to the 'synthetic' electricity futures.

Creating a ´synthetic´ FTR obligation is also possible by using electricity futures (or CfDs depending on the market structure) traded in the forward market of two BZs. From a TSO perspective, a ´synthetic´ FTR Obligation financially equivalent to a traditional FTR can be designed by emitting equal volumes conditionally on the price spread of the chosen hedging products in each BZ. An example is illustrated in Box 2.

Using existing derivatives to support the liquidity will have a smaller impact on the market than introducing new products to provide additional hedging opportunities. Introducing a product that enables market participants to hedge the price of an illiquid BZ by using a forward contract of a liquid BZ may not strengthen the liquidity of illiquid BZ. It may even drain it further as it steers market participants to the forward contract of the already liquid BZs. Adding hedging opportunities to the illiquid BZ does not steer market participants to the hedging opportunities of the liquid BZ, but hopefully market participants get an initial volume that can be further traded in the secondary market of the illiquid BZ.

Box 1: 'Synthetic electricity futures'

By combining an electricity futures contract traded in a liquid electricity forward market with a FTR Obligation, a 'synthetic' electricity futures contract could be created for a BZ with a less liquid electricity forward market.

For example, an electricity future for a BZ A with an illiquid electricity forward market could be 'synthetically' provided by combining an electricity future in a neighboring bidding zone B, with a more liquid electricity forward market, and a FTR Obligation between the two bidding zones. Figure 6 shows the principle of synthetic futures.

'Synthetic' futures can be defined in BZs featuring low liquidity (in the figure, Poland) starting from the futures price PDE in a bidding zone featuring high liquidity (in the figure, Germany) and the FTR Obligation between the two areas. Risk-free arbitrage implies that the futures price in Germany and Poland are kept in line with the FTR Obligation market price.

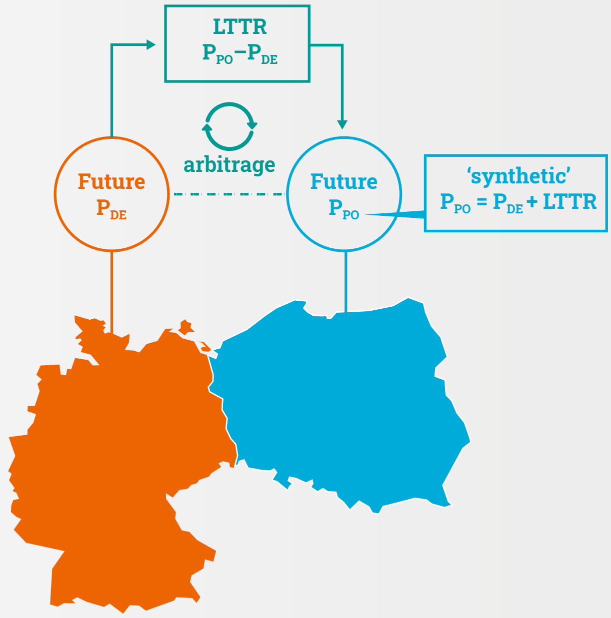

Figure 6 – Synthetic futures

Box 2: Pilot project on EPAD Auctions

An example of synthetic FTR Obligations is Svenska kraftnät's pilot project for auctioning of EPADs with coupling. The coupling consists of four separate auctions; one for buy and sell positions in each BZ, with a matching criteria that there must be positive price difference between sell and buy for the auction to clear. The results of the auctions will be that the Svenska kraftnät will be counterparty in sell and buy EPAD positions in two adjacent BZs with symmetric volumes.

Svenska kraftnät will generate Day-Ahead Congestion Income on the BZB and as the EPAD positions are settled based on the Day-Ahead prices of each BZ, Svenska kraftnät will always have a natural hedge against its EPAD positions. The coupled EPADs are, from a TSO perspective, financially equivalent to an FTR Obligation and, from the market participants' perspective, they have attained a hedging instrument against the BZ price. A numerical example can be seen in Figure 7.

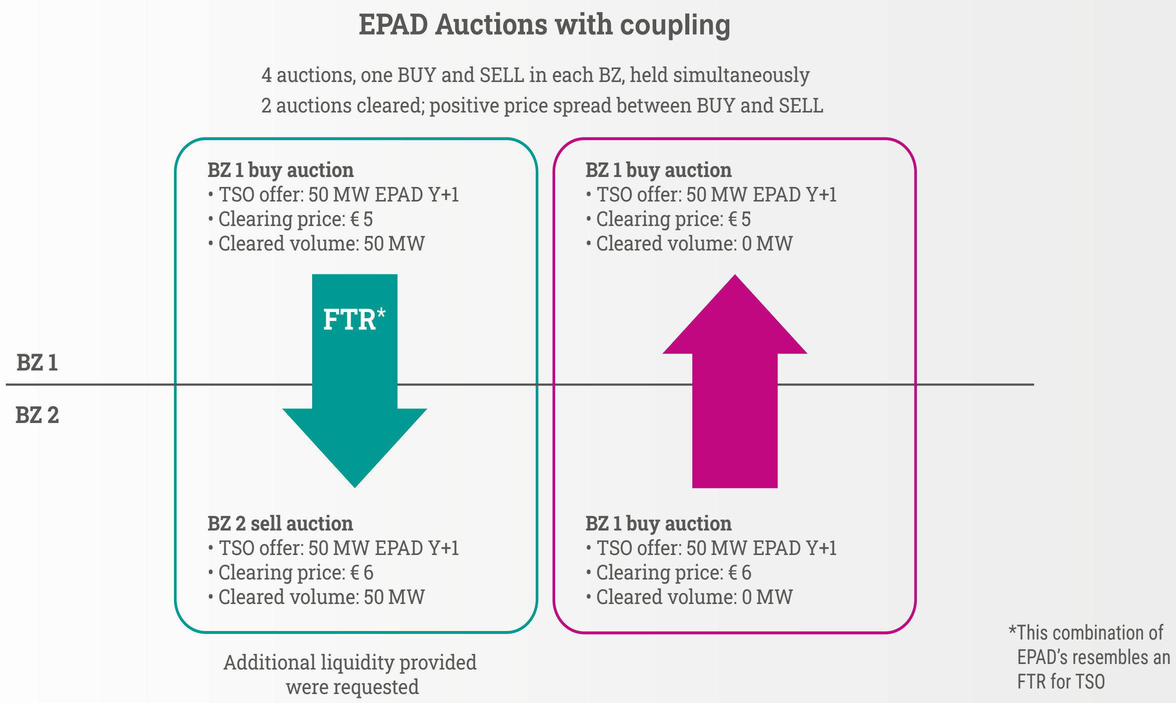

Figure 7 – EPAD Auctions

5.1.3 Zone-to-Zone vs. Zone-to-hub LTTRs

LTTRs from the proposed Approaches 1 and 2 can be offered as zone-to-zone (Z2Z) or zone-to-hub (Z2H) products or even both in parallel. In that manner, Z2H FTRs could be complementary instruments to the default Z2Z products. This can be beneficial for providing stable hedging opportunities for market participants in small, illiquid bidding zones. As an alternative for the forward market of their own illiquid market, they would prefer to hedge themselves on the hub forward market if this one has more liquidity. Via Z2H, FTR market participants can adequately hedge themselves against the price differences of the spot price of their own market against the fixed forward contract on the hub.

Allowing Z2H FTRs in general can come with benefits but also risks. A benefit could be that a hub makes it easier for market participants to trade between non-neighbouring BZs. In terms of the initial auctions, at least the trading volume is unlikely to increase as the allocation always uses the underlying capacity provided by TSOs. In terms of the secondary market, it might have a different effect and the hub would pool liquidity. On the other hand, the pooling of liquidity at the hub would reduce the liquidity at other forward markets as the liquidity would be split. Regarding the underlying capacity provided by TSOs, however, the ZTH arrangement becomes more complex and would need to be further analysed in terms of its implications for e. g. firmness, redispatching needs, etc.

The design of the hub is crucial (i. e. the region to which the hub applies and the calculation of the hub price) and has an impact on the Z2H FTR Obligations. If done incorrectly, it could even have a negative impact. However, with Z2Z FTR Obligations, market participants have a clear understanding of the price formation and can value the product better.

5.1.4 Capacity calculation for multiple years in advance

Policy Option 1 envisages that either FTR Options or FTR Obligations are offered at least for annual, quarterly and monthly delivery periods, for base load and peak load profiles. This is in line with the delivery periods typically traded in electricity (commodity) futures markets.

In the ACER and CEER draft policy paper as well as during recent consultation responses from market participants, it was requested to offer LTTRs for up to three years in advance. ENTSO-E recognises the benefit for market participants of long-term forecasts of capacities in hedging and planning of business activities. However, ENTSO-E wishes to underline the huge uncertainty that comes along with the extension of the time horizon and the higher financial burden on end consumers due to the risk shift from market participants to TSOs. With longer time horizons, market participants will likely even pay less for an LTTR. The long-time horizon can also lead to the additional need of redispatching in real time and higher costs due to more frequent cases of curtailment.

Currently, some TSOs such as Svenska kraftnät[26] provide long-term outlooks (up to 10 years in advance), but these are not associated with any process of allocation of capacities. These forecasts are mainly done with a statistical approach with simple market models that consider future scenarios not just for the transmission system itself but also changes in consumption and production patterns. These outlooks are associated with uncertainties and should be treated as outlooks only and not be used for calculating capacities.

From a capacity calculation perspective, moving beyond the 1-year timeframe is uncharted territory as there are no coordinated planning processes on the regional level that allow the state of the grid to be modelled more than 1 year ahead of real time. Consequently, performing sophisticated capacity calculations based on forecasted scenarios cannot be expected. Therefore, a first assumption is that capacity calculation for the 2-year and 3-year ahead auctions would have to be facilitated by a simple statistical approach. This approach would allow for capacity calculation for longer time horizons but would potentially even increase the risk and the associated financial burden to be covered by end consumers.

The co-existence of a statistical approach (2-year and 3-year ahead) and a diverging capacity calculation approach (as from 1-year ahead) will have to be further investigated. As it does not appear to be straightforward to make them consistent (how to handle resales, how to handle cases where the capacity issued 3-year and 2-year ahead of time is not present anymore in the year-ahead grid models), a broader application of the statistical approach should not be excluded.

Additional details on the capacity calculation process are presented in the following two sub-sections:

26 Svenska kraftnät provides long-term outlooks in the form of the long-term market analysis, Short term market analysis spanning from 3 years ahead to 10 years and in the System development plan outlooks on even longer time horizons are published.

5.1.4.1 Splitting rules review

Issuing LTTRs more in advance will also require policy makers to govern how capacity is to be split across the 3-year, 2-year and 1-year horizons as the cumulated level of capacity provided in those auctions will not exceed the level of capacity provided one year ahead today. It should be clear to policy makers and market participants that the establishment of additional auctions cannot lead to more total capacity as the underlying capacity is still based on physics. Consequently, the offered capacity in each auction is reduced, which would have a negative impact on the liquidity. In doing so, a balance must be found between the valuation of forward / future products across the different time horizons and the risk taken on behalf of end consumers to maintain revenue adequacy for a given level of capacity. Most likely, this would be somewhat arbitrary in the beginning but it could be periodically reviewed by examining how volumes are developing in the different timeframes. Currently, the rules establishing how to split capacity between different long-term timeframes is established under the regional methodologies for splitting long-term cross-zonal capacity[27].

5.1.4.2 Revenue adequacy and LTA Inclusion

The 'risk taken on behalf of end consumers' statement deserves some clarification. Today, revenue adequacy is 'mostly' guaranteed via LTA inclusion in the day-ahead market coupling ('mostly' as there are scenarios, i. e. reaching the price cap in market coupling or a decoupling event, which require complementary measures, meaning additional costs covered via network tariffs, to ensure revenue adequacy). However, LTA inclusion affects the physical flows (and thus grid security and operational costs) allocated in day-ahead, even up to the point where curtailment of LTTRs is necessary. This is likely to be even more the case if LTTRs are issued up to 3 years in advance. On the other hand, the physical capacity used for the price formation in the Day-Ahead market is the underlying for LTTRs. The disconnection from the actual physical capacity has an increasing effect on the costs as in cases where the capacity given on long-term exceeds the capacity provided in Day-Ahead, not only does the income of TSOs (Day-Ahead spread) decrease due to lower capacity in Day-Ahead than in long-term but also the price spread to be paid to LTTR holders increases as lower capacity increases the spread.

Therefore, the extension of the time horizon as well as the termination of LTA-Inclusion would increase the undervaluation, which is ultimately always a bill paid by end consumers.

It may be doubtful that LTA inclusion is a sustainable solution as assumptions up to 3 years in advance that prove to be wrong would disturb short-term operations. On the other hand, those exact cases would increase undervaluation. Policy makers can consider guaranteeing regulatory revenue adequacy as an alternative to the practice of LTA inclusion. Consequently, the financial forward products would no longer impact the allocated physical flows, and a layer of complexity in the design of short-term markets would be removed. If policy makers decide on regulatory revenue adequacy, which consequently leads to higher costs to be reimbursed via end consumers, they shall aim at a harmonised process among the member states by describing the mechanism of cost and risk coverage via network tariffs in the respective regulation and shall include immediate cost coverage.

27 In accordance with the principles of Article 16 of Regulation (EU) 2016/1719.

5.1.5 Capacity allocation

The following sub-sections explore some further improvements of the allocation framework, ensuring volume adequacy and introducing a minimum auction price for the capacity allocation process.

5.1.5.1 Allocation framework

To promote competition and to prevent hoarding of FTRs, auctions shall take place sufficiently in advance and with an increased occurrence.

The yearly auctions would allocate annual FTRs for each of the three subsequent years. Quarterly auctions would allocate FTRs for at least each of the subsequent four quarters. Monthly auctions would allocate FTRs for at least each of the subsequent three months. When auctions for FTRs for different delivery periods coincide in timing, the auction for FTRs with a longer delivery period would be run before the auction for FTRs with a shorter delivery period, so that any unallocated capacity in the former auction can be offered for allocation in the latter auction. Therefore, ahead of the start of each year, the auction for annual FTRs would be run first, followed by the auction for the quarterly FTRs. The auction for the monthly FTRs would be run last. Similarly, ahead of the start of each quarter, the auction for quarterly FTRs would be run first, followed by the auction for the monthly FTRs.

As a starting point, the available volumes of FTRs which could be issued and backed by the congestion rent in each direction on each border for a specific delivery year or for the different quarters in that year (in case of seasonal differences in the underlying physical capacities) would be first divided into the shares to be assigned to FTRs with delivery periods of different lengths (annual, quarterly and monthly) and subsequently spread over the different rolling auctions in which they are allocated.

In any case, the allocation framework outlined above is only a starting point and would be one of the features to also be calibrated on the basis of the feedback received as a result of the consultation of market participants and other relevant stakeholders.

Furthermore, it should be highlighted that the underlying capacity will remain of the same volume but will rather be split between the different auctions.

5.1.5.2 Ensuring volume adequacy

To improve the access to liquidity of the forward market and improve the competitiveness of the LTTR's auction, the allocated volume of LTTRs per auction have to fit the market forward needs. This could be done with a statistical study of the average volume of forward product sold during the year.

As the forward market is a continuous market, several auctions per LTTR product along the year have to be to set up with a limited volume of capacity per auction. This measure will create more liquidity along the year on the FTR market as well as on the forward market and improve the interest of the LTTR auctions for market participants.

Furthermore, by allocating less FTR volume per auction, market participants will bid a higher price due to the scarcity effect of the capacity.

5.1.5.3 Introduction of a minimum price

Generally, auctions only provide an adequate price of a product if the product is scarce and if sufficient market participants compete for the product. With the netting nature of FTR obligations, the scarcity of LTTRs decreases considerably and the level of competition for FTR option currently is at least questionable (and could already be a reason for the current level of undervaluation). To counterbalance this, a minimal price should be set up at which LTTRs are to be sold at the auctions. This minimal price should be based on a transparent mechanism and should be communicated to market participants before an auction. For FTR Obligations, the minimal price could be based on the price differences between futures of neighbouring BZs as that would be the value a FTR Obligation has as a hedging instrument for market participants to enter a market from a neighbouring bidding zone. For FTR Options, the minimum price could be even higher as it provides market participants with lower risks. All the offers below this minimal price would be rejected, and the non-allocated capacity would be offered at the next auction.

5.1.6 Long-Term Flow-based allocation impact

Long-Term Flow-Based Allocation (LTFBA) will be introduced according to the decision of NRAs and ACER on capacity calculation methodologies in Nordic and Core Capacity Calculation Regions (CCRs). Flow-based capacity calculation should allow allocation of the scarce transmission capacity more efficiently as cross-zonal capacities between BZs are highly interdependent. However, it is not only positive effects that can be linked with this improvement. Instead, some negative impacts of LTFBA (some of which are currently being investigated by the TSOs and JAO) are listed below:

- Due to the direct competition between BZ borders during the flow-based capacity allocation, results with zero allocated rights at a BZ border despite existing demand can be achieved. Achieving more balanced liquidity and hedging opportunities for individual BZs could thus be more difficult. However, high bidding prices at one border should not hinder allocation on low priced distant BZ borders. TSOs consider such behaviour as market based and correct.
- The flow-based capacity calculation and allocation processes will both require a longer time and be more complex than the previous process which will have various impacts on the auctions. In case of a valid market participant contestation or major unexpected failure of allocation process, the auctions would need to be rerun which would then also impact the timeline of auctions. Because of this nature, it will be challenging to introduce more auctions compared to the status quo, whether it is in terms of increasing the granularity or introducing auctions more in advance.
- As all bidding zone borders in a CCR are linked together and run as one auction, market participants cannot post collateral on individual borders (auctions) separately and consequently, the entry barrier will be much higher. It is therefore very important to coordinate the collateral system so that it does not create an entry barrier for market participants, but on the other hand limits speculation and covers risks on the side of TSOs.

As introduced before, the implementation of the proposed improvements for Approach 1 and 2 would be subject to the results of the investigations into the impact of LTFBA.

5.2 Policy Option 2 (Approach 3): Purely financial forward market

Historically, TSOs have offered capacities on some of their interconnectors to market participants. This began as PTRs for the market participant to engage in power contracts with the market participant in the adjacent BZ. The nomination of these physical transmission rights declined over time and it was decided, at more and more borders, to switch from physical transmission rights towards FTRs. This was a switch requested by market participants, and which decreases the entry barriers for new market participants. Essentially, at those borders where TSO are providing FTRs, TSOs are providers of financial hedging instruments against the day-ahead price spread volatility between two adjacent BZs. The cash flow to cover for the offered FTRs comes from the congestion income generated through the interconnector. As forward market liquidity and market depth (see section 4.1) are well developed in some BZs, LTTRs might not further develop the respective markets. In these markets, it is therefore important for TSOs to take an observer role and allow the market to develop in the direction market participants finds suitable.

One basic prerequisite to enable this is an environment free from hidden and/or indirect barriers that hamper the development of markets. Policy makers should carefully analyse these, especially in illiquid BZs. Next, improving simplicity and transparency for market participants in forward markets is key to enabling markets to further develop and liquidity to increase. However, these issues are outside of the TSO influence and cannot be solved by LTTRs and their design.

Under Policy Option 2, the proposed Approach 3, TSOs would not need to be involved anymore and the end consumer would fully benefit from the day-ahead congestion income as it can be returned to the tariffs. Approach 3, therefore, strives towards forward/futures markets that manage themselves as many of the traits of the LTTR product are to be found in the already existing forward markets.

In theory, the purely financial market offers some advantages over the FTR-based markets in terms of economic efficiency. The price-risk facing the market participants does not disappear when a hedging contract is agreed. Rather, the hedging contract moves the risk from 'the hedger' to a party willing to absorb the risk. Thus, the two parties need to agree on a price for the contract such that the 'hedger' is faced with a market-based cost (that the one providing the hedge is willing to commit to in order to absorb the risk). Consequently, the hedger is faced with the correct market-based price of risk involved in both investment, localisation and dispatch decisions. This will (theoretically) incentivise the formation of correct long- and short-term electricity-prices in all BZs. TSO-offered products are, on the other hand, frequently sold at prices below its economic value (underselling). Thus, hedging a contract based on such products will face the hedger with a subsidised price for the hedge, incentivising extensive risk taking, which will distort the market prices for electricity in a non-efficient manner.

In terms of product design and hedging quality, a FTR Obligation is fully equivalent to a pure financial forward spread product (e. g. Power Future Spreads at EEX). A spread product can be traded directly - if the product does exist – or synthetically (see sub-section 5.1.2.4) via selling the one leg and buying the other one. As an example, an FTR Obligation for Germany to France i. e. 'DE→FR' is equivalent to selling a forward for Germany and buying a forward for France for the same underlying time period.

It would also be equivalent to use a Z2Z (i. e. LTTR) or Z2H product to achieve a cross-zonal hedging need of a market participant. The difference between both being how the residual risk correlates with the original hedging need:

- for Z2Z, the residual risk is the locational risk deriving from the price variation between two BZs; and
- for Z2H products, the residual risk is the locational risk deriving from the one BZ to the hub.

The differences between LTTR and forward/futures markets lie in the manner of trading and in the counterparty:

- for LTTR, the trading is done via an auction, and the counterparty are the TSOs for that border, whereas
- for forward market, the trading is done via continuous trading, and the counterparty is another market participant, often through the exchange or brokers. The requirement for this equivalence, to the LTTR, is sufficient liquidity for both legs of the spread product in the forward market.

With the current legislation and risk profile of TSOs, the added hedging possibilities provided to the BZs are always limited by the capacity of the underlying grid (e. g. the cross-border capacity between BZs). Therefore, illiquid BZs can rely only on cross-border capacity to enter a liquid market. Furthermore, LTTRs are hedging products financed by congestion income which might even prevent the market from inventing its own solutions to tackle illiquidity. These solutions would also be more fit-for-future as regulated solutions because they are flexible and can promptly react to the changing needs of the market and its environment. The improvements for TSO-issued products discussed for Policy Option 1 should mitigate undervaluation, but the difference in risk profile of a TSO vs. commercial party remains. Hence, it is unlikely that TSO-issued and commercial cross-zonal products can compete with each other side by side. Opting for TSO-issued products is likely to exclude commercial development of cross-zonal products.

However, in the TSO opinion, there are possibilities to where the future markets could evolve for current and new members of the EU. Some of the possibilities do not preclude any involvement of TSOs, and some involve the short-lived funding by the TSOs in order to start up the future market in the particular BZ.

A market model with harmonised products in future markets in all European BZs could further enable liquidity. This would increase the equivalent trade and minimise the complexity and risks for market participants, for example resulting from different terms, conditions, settlement and collaterals. This idea is further developed under 'Box 3 – Centralisation of trading and collaterals'.

In addition, if the liquidity level is not adequate in a BZ, a market maker could be applied for a limited period of time. This measure would support the market and support the increase of liquidity with a less interventionist nature than TSO-issued products. This idea is further explored under 'Box 4 – Market Making'.

Box 3: Centralisation of trading and collaterals

For TSOs as providers of hedging opportunities

Under Policy Option 1, Approach 2, FTR Obligations are allocated via auctions and then traded in secondary markets. Due to the obligation nature of these contracts, arbitrarily large volumes of FTR Obligations may be exchanged, with the only constraint that the net open position in any given direction, excluding the 'synthetic FTR Obligations', corresponds to the FTR Obligations issued by the TSOs.

To reduce collateral requirements for market participants, trading of FTR Obligations could take place at the same exchanges where the corresponding electricity futures are traded. These entities could either be designated by the respective Member States (similar to National Electricity Market Operators [NEMOs]) or be tendered. This would reduce collateral requirements because the margin required from a participant holding a position including both electricity futures and FTR Obligations would be calculated by netting out the market risk stemming from the electricity futures and the FTR Obligation. In this case, a market participant using the FTR Obligation for cross-border hedging would not face significantly higher collateral requirements than if they entered an electricity future in their local BZ. In addition, the harmonisation and centralisation might help to bundle liquidity. Further product evolutions shall be aligned between the designated power exchanges and Market Participants on a Member State or regional (CCR) level.

Conversely, if electricity futures and FTR Obligations were cleared separately on different trading platforms, the participant would be required to provide collaterals for both the electricity futures in bidding zone A and for the FTR Obligation.

For purely financial markets

To harmonise products and align services, central entities shall be used in each BZ to organise the trading of forward electricity derivates. These entities could either be designated by the respective Member States (similar to NEMOs) or be tendered. The central entities shall be competitive and privately owned. As NEMOs in Day-Ahead, these central entities would be obliged to offer harmonised services/products and therefore submit joint proposals for some Terms and Conditions to ACER (i. e. a methodology for harmonised standard products that contains at minimum 5 years ahead, monthly, quarterly and yearly derivates, a methodology for operation and organisation of a continuous secondary trading for their standard products or a methodology for harmonised and simplified trading requirements [incl. collateralisation] to lower barriers of entry for market participants).

OTC platforms shall be able to continue their activities (complementary to the central entities).

Box 4: Market Making

Member States and/or NRAs in collaboration with relevant market participants, End Consumers and TSO/s should assess the liquidity of the (national) forward/future market. If the liquidity is not sufficient and needs enhancement to be 'kick-started', a market maker can be installed in the respective (national) market. A regular assessment (e. g. every second year) of liquidity indicator (e. g. churn factor, bid-ask spread) would provide a basis upon which to decide on the further use of a market maker.

The task of such a market maker would include actively buying and selling futures at the forward power exchange in the respective BZ(s) and act as a counterparty for market participants otherwise unable to get a match. Compared to regular market participants and market makers already active in forward markets, this market maker would have access to additional funding to accept losses in its activity. NRAs would hold a tender for private entities to apply as a market maker and the entity with the lowest fee would be chosen for a certain period of time (e. g. 2 years). The additional funding the market maker could use would be provided by the TSO(s) of the respective BZ(s) as they would provide 5 % of their day-ahead congestion income to the market maker. If applied in all European countries, the market maker would have had 240 M€ funding in 2021 (5 % of 4.78 Bn € total net CI in 2021). If a number of Member States decided to hold a tender together, the chosen market maker would act in several BZs in parallel.

Ideally, the respective authorities (Member States/NRAs) define a framework for the market maker to follow. Such a framework could include the incentive to balance the activity on each BZ (i. e. buy and sell the same amount) and set a bid-ask-spread that the market maker shall operate in. That way, the financial risk a market maker takes and the influences on the market are kept at an acceptable level.

To protect end consumers, the risk inherent to the task of a market maker shall not be transferable into the network tariffs. Any support of the market should always consider the benefit of the end consumers, which would not be fulfilled by end consumers covering market risks via tariffs. A market maker could also be motivated to take an unnecessary high risk if the financial backing would exceed the funding mentioned above.

If regulatory authorities decide that the end consumer needs to cover risks by the market maker, they shall aim at a harmonised process among the member states by describing the mechanism of cost and risk coverage via network tariffs in the respective regulation and shall include immediate cost coverage.

6 Evaluation of Policy Options

In this section, the main issues described in section 4 are discussed vis-à-vis the assessed main approaches presented in the previous sections, outlining if the proposed options are suitable to tackle each problem (in **green**), how they contribute to it (in **red**) or if they are neutral (in **blue**). Furthermore, the different risk profiles of market participants, TSOs and end consumers are assessed for each option. A summary of the three tables below can be found in Annex 3.

6.1 FTR Options with adjustments

	CRITERIA	APPROACH 1: FTR OPTIONS WITH ADJUSTMENTS
1	**Liquidity**	› With the new allocation framework (i. e. more auctions per product), access to liquidity in the forward markets and hedging opportunities are improved, which promotes competition and prevents hoarding of capacities. › Illiquid BZs get access to the liquidity of more liquid neighbouring BZs. › Market has no incentives to further develop liquidity in their home BZs (i. e. national hedging/forward markets).
2	**The LTTR undervaluation**	› The greater the occurrences of auctions and the increase of number of FTR products issued, the greater the attractiveness of LTTRs as continuous hedging products, thus leading to higher LTTR prices. › The introduction of a secondary market (i. e. continuous secondary market) might have a positive effect on the undervaluation as a transparent price forming process that gives market participants better information of the value of LTTRs. › The introduction of a minimum auction price would support the competitiveness of the market and ensure that undervaluation does not increase above a certain level (more in this in 5.1.5). › In the event that one BZ has an illiquid electricity forward market, FTR Options may not necessarily solve the issue of undervaluation in the short term, because if participation in FTR auction is limited the price could still form below the efficient level. The undervaluation in illiquid market is also due to inadequate price formation in the underlying forward market for the particular BZ(s).
3	**Secondary market**	› Continuous secondary market for FTR Options will support the liquidity of the market as market participants would have the opportunity to sell/buy their FTR portfolio at any time, depending on the trend of the FTR value. › However, it will be challenging to design a secondary market for FTR Options with low entry barriers for market participants. As secondary trading falls under financial regulation it is questionable if the request for it will be higher than today.
4	**Collaterals**	No changes in the current collateral scheme necessary.
5	**Complexity of hedging between not neighbouring BZs**	As FTR Options are not equivalent to electricity futures, it is more challenging for market participants to hedge between not neighbouring BZs.
6	**Costs on ensuring firmness**	The level of firmness as provided in 4.6 should be reflected in the decision on the design of a future forward market.
7	**Future proof for RES integration**	No changes to the current market model.
8	**Risk profile of MPs**	› FTR Options with adjustments would still provide market participants with good profit maximisation possibilities. › Forecasting of FTR Options prices is more complex for market participants as they cannot directly compare them with the price of futures contracts.
9	**Risk profile of TSOs**	› The procedure of long-term capacity calculation is very time and resource consuming. Furthermore, it is currently not clear how capacity shall be calculated for more than one year in advance. › With LTA inclusion, the allocated long-term capacity has an effect on the physical grid. In cases where TSOs are offered too much long-term capacity, remedial actions must ensure that system security is maintained. In the event the long-term capacities cannot be provided in Day-Ahead, TSOs have to curtail them and reimburse the LTTR holders. An alternative to LTA inclusion may be considered to avoid this effect (other revenue adequacy without impact on the physical grid [i. e. risk and immediate cost coverage] measures needed).
10	**Risk profile of end consumers**	› End-consumers could benefit through access to hedging opportunities. › The additional redispatching costs and reimbursement payments will translate into grid tariffs. An alternative to LTA inclusion may be considered to avoid this effect (other revenue adequacy [i. e. risk and immediate cost coverage] measures needed).

6.2 FTR Obligations

	CRITERIA	APPROACH 2: FTR OBLIGATIONS
1	**Liquidity**	› With FTR Obligations, 'synthetic' futures can be created for illiquid BZs that can then be used as references (due to non-arbitrage) for the development of a liquid home BZ. In the event of heterogenous liquidity, fewer markets will benefit from more liquid neighbouring markets. › FTR Obligations issued in opposite directions on the same BZ border can be netted out, in the sense that their payoffs during the delivery period are equal in absolute value and opposite in sign, and therefore they net themselves out. This allows more capacity to be offered and thus more 'hedging products' towards the market participants compared to the PTRs/FTR Options.
2	**The LTTR undervaluation**	› The pricing of FTR Obligations is immediate in case both BZs feature a liquid electricity futures market. In this case, the pricing of the FTR Obligation is obtained by a non-arbitrage condition and it is expected that speculators and financial operators will materially contribute in ensuring an efficient price level for LTTRs. › In the event one BZ has an illiquid electricity forward market, FTR Obligations may not necessarily solve the issue of undervaluation in the short term because if participation in FTR Obligations auction is limited, the price could still form below the efficient level. The undervaluation in illiquid market is also due to inadequate price formation in the underlying forward market for the particular BZ(s). › FTR Obligations allow for the definition of 'synthetic' futures that support the development of liquidity in currently illiquid BZs. As liquidity develops, it is expected that arbitrageurs will progressively extract the risk-free profit deriving from undervaluation of LTTRs and ensure that the efficient price level is reached. › The introduction of a minimum auction price would support the competitiveness of the market and ensure that undervaluation does not increase above a certain level (more in this in 5.1.5).
3	**Secondary market**	As FTR Obligations are effectively financial futures, it can be expected that the secondary market will become more active. FTR Obligations would be continuously traded after being issued from TSOs.
4	**Collaterals**	Due to its symmetrical nature, the implementation of FTR Obligations requires changes in the collateral scheme (either higher collaterals or mark-to-market collateral mechanism).
5	**Complexity of hedging between not neighbouring BZs**	Merging several zone-to-zone FTR Obligations enables market participants to hedge between not neighbouring BZs. As the flow-based calculation requires simultaneous allocation, the algorithm for the allocation could even be able to translate the desire for a hedging product between non-neighbouring BZs into the ideal combination of zone-to-zone FTR Obligations.
6	**Costs on ensuring firmness**	The level of firmness as provided in 4.6 should be reflected in the decision on the design of a future forward market.
7	**Future proof for RES integration**	No changes to the current market model – slight benefit related to the improvements in the secondary markets which provide more flexibility.
8	**Risk profile of MPs**	› Forecasting of FTR Obligations prices becomes easier for market participants as they are directly comparable with the price of futures contracts. › Under FTR Obligations, market participants are obliged to pay the market spread to TSOs in the event it is negative. Hence, market participants are exposed to higher price risks, but only if they do not use the FTR Obligation to create synthetic futures.
9	**Risk profile of TSOs**	› The procedure of long-term capacity calculation is very time and resource consuming. Furthermore, it is currently not clear how capacity shall be calculated for more than one year in advance. › TSOs are exposed to higher risks if market participants are not able to pay the negative market spreads. This risk can partly be reduced by introducing a clearing house. › With LTA inclusion, the allocated long-term capacity has an effect on the physical grid. In cases where TSOs offer too much long-term capacity, remedial actions must ensure that system security is maintained. In the event the long-term capacities cannot be provided in Day-Ahead, TSOs must curtail them and reimburse the LTTR holders. An alternative to LTA inclusion may be considered to avoid this effect (other revenue adequacy without impact on the physical grid [i. e. risk and immediate cost coverage] measures needed). › The LTFBA project might be impacted by switching to FTR Obligations.
10	**Risk profile of end consumers**	› Due to the symmetric nature of FTR Obligations, money-making gets less attractive to market participants, which can result in higher benefits for market participants who really need to hedge (e. g. generators, suppliers). › The additional redispatching costs and reimbursement payments will translate into grid tariffs. An alternative to LTA inclusion may be considered to avoid this effect (other revenue adequacy [i. e. risk and immediate cost coverage] measures needed).

6.3 Purely financial forward markets

	CRITERIA	APPROACH 3: PURELY FINANCIAL FORWARD MARKETS
1	**Liquidity**	› Liquidity is not split into different markets. No liquidity out-migration from smaller illiquid zones to already very liquid zones. › The market is free to develop the products and solutions which best fits their purposes. › To ensure a functioning purely financial market, a certain amount of liquidity needs to be in the BZs (requires measures to support/develop liquidity in less liquid areas).
2	**The LTTR undervaluation**	LTTRs are not issued anymore, which means that no welfare transfer from end consumers to some market participants take place.
3	**Secondary market**	Not needed as there are no LTTRs, but the market can provide a secondary market for products providing hedging opportunities against the volatility of price spreads, which already happens now.
4	**Collaterals**	› One layer of collaterals (for LTTRs) not needed anymore and reducing overall complexity. › Collaterals' issue only affects commodity markets. › Harmonisation of collaterals' scheme yet to be further assessed.
5	**Complexity of hedging between not neighbouring BZs**	It can be easily achieved by buying a future in one zone and selling it in the other (product harmonisation of futures could contribute to this).
6	**Costs on ensuring firmness**	No costs to ensure firmness as TSOs do not provide LTTRs.
7	**Future proof for RES integration**	› By giving the freedom to the market to define their own fit-for-purpose products, a wider range of financial products is expected which are more suitable for RES. › Correct pricing signal as risks are kept with the risk owners and not shifted towards TSOs and thereby socialised.
8	**Risk profile of MPs**	› Perceived risk/reward could be too high for any commercial counterparty (including a potential market maker) to offer cross-zonal products in a particular BZ. › Not having access to aptly priced cross-zonal hedging could reduce forward hedging opportunities in inherently illiquid BZs or limit forward trading to large players only. › Market would develop better suited products to handle the risks. › Financial products adapt more swiftly to the market conditions.
9	**Risk profile of TSOs**	› No risks for TSOs as they are no longer involved in the forward market. › Capacity calculation can be done for the timeframes where the status of the grid can be predicted the best.
10	**Risk profile of end consumers**	› End-consumer is no longer affected by firmness costs or undervaluation of LTTRs, which could lead to lower network tariffs. › However, in illiquid BZs, the absence of cross-zonal capacity could limit the access to hedging opportunities (i. e. fixed contracts) for end-consumers.

7 Conclusions and proposed Actions

In this Policy Paper, ENTSO-E develops two main Policy Options for the future electricity forward market: one where TSOs continue to be providers of hedging opportunities by issuing LTTRs, and another where the financial forward market is believed to identify its most suitable solutions by itself without any involvement of TSOs. In both Policy Options (which unfold as three approaches) several improvement possibilities are described which are believed to contribute to the key considerations.

The evaluation of the three main approaches (FTR Options with adjustments, FTR Obligations and a purely financial forward market) shows that all the approaches are likely to solve some of the issues mentioned in section 4. At the same time, all approaches also present drawbacks and come with a shift of risks between TSOs and market participants.

The proposed approaches and improvements shall be further developed and assessed to ensure a clearer understanding of their implications for all stakeholders. Areas for further investigation include the formation of secondary markets, the optimisation of LTTRs auction timings, the development of a method to match the offered LTTR capacities to volumes traded on forward markets in order to ensure volume adequacy, alternative instruments to LTA inclusion or the design and pricing of zone-to-hub FTR.

The non-exhaustive list below gives an overview of topics for further assessment:

- Fast implementation of ACER and CEER's idea of reducing firmness (in the event of decoupling);
- Optimisation of auction timings (e. g. shortening the time until publication of auction results, shifting auctions closer to delivery time), considering the impacts from LTFBA as well as market participants' opinions on the potential improvements;
- Design of Z2H FTR products (hub definition, price calculation, link with capacity calculation, etc.);
- Design of Z2H FTR products as a potential solution to solve the challenges of BZ reconfiguration;
- Development of a method to match the offered LTTR capacities to the electricity forward markets liquidity to ensure volume adequacy;
- Structure and time plan for long-term auctions that fit market participant needs the best (analysing the liquidity of electricity forward markets to identify the best structure for LTTR auctions) while considering the impacts of LTFBA;
- Alternative to LTA inclusion for revenue adequacy; and
- Assessment of barriers for the development of liquidity.

A further very important topic not tackled in this Policy Paper is the scope of implementation. Although all the approaches claim to be introduced on all European borders, it is questionable if the desired harmonisation matches with the significant differences among the current local forward markets. The assessment of which level of harmonisation (e. g. per BZ border, per CCR, or other) brings the greatest advantages should be carefully performed.

ENTSO-E will continue to assess and prepare the described improvements in order to give valuable input in the upcoming debates with ACER regarding how the future forward electricity market can be best organised.

Annexes

Annex 1: Overview of the current Long-Term Markets

With increasingly larger shares of RES, more fluctuations on supply and demand conditions are expected, ultimately leading to an increasing volatility of spot prices. The expectation is that although more price spikes may happen, periods of very low prices when RES-generation is extremely high will also be seen. These significant changes in prices, in turn, will impact the risk for market participants, who will therefore strive for hedging opportunities in forward markets in order to reduce their exposure to the fluctuations. There are two timeframes in which market participants particularly require hedging: the 'investment-driven' timeframe covering 10–15 years and the 'trading-driven' timeframe covering up to 3 years.

Investors aiming to build up new generation capacity require certainty on revenues over a longer time period such as 10-15 years. Ideally, spot prices not only send price signals for the short-term but, through expected price levels, also for the long-term time period. With increasing uncertainty regarding the expected long-term price levels, alternative solutions are needed to ensure further long-term investments. With the help of a variety of long-term instruments (feed-in-tariffs, feed-in-premia, contracts for difference, Capacity Remuneration Mechanisms), the investors' exposure to the price fluctuations were generally reduced. In addition, LTTRs can be viewed as a useful tool to hedge against the volatility of spot prices in the long term. To actually support investments, however, the current timeframe covered by LTTRs is too short and would need to be significantly extended.

In the 'trading-driven' price horizon, market participants holding portfolios of generation and consumption have the need to hedge against the risk of fluctuations in the spot prices. The time horizon of 'trading-driven' hedging is shorter than in the case of 'investment-driven' hedging, but still materially long compared to the dynamics of spot prices. Typically, market participants seek certainty over their cost/revenues for periods ranging from 1 to 3 years. This annex is focused on the second alternative for hedging against the spot price volatility, i. e., entering into 'forward' transactions in order to secure the revenues, for a certain period of delivery in the future (the 'delivery period' of the forward contract).

1 Forward Markets Assessment

Forward markets pursue the objective of providing market participants with hedging opportunities that should be:

- **Effective**, i. e. capable of addressing the hedging requirements of market participants. This requires products that can minimise participants' exposure to (the variability of) the spot price;
- **Efficient**, i. e. capable of providing hedging at least cost. This requires reaching a sufficient level of market liquidity, price discovery and harmonisation of product design, which could be assisted by the concentration of trading in one or a few marketplace(s), or at least their coordination and harmonisation. These features enable market participants to procure hedging opportunities at low cost, including by keeping transaction costs as low as possible. In particular, this entails:
  - Low bid-ask spreads, so that the cost of purchasing and subsequently reselling the same product is low, aiming at high churn factors[28] and therefore liquidity;
  - Low collateral requirements, so that barriers to the participation in the forward markets are reduced.

Currently, there are two forward/futures markets enabling market participants to hedge their positions within and across BZs in Europe:

- **Electricity forward markets.** In these markets, electricity derivative products are traded for most BZs, where the underlying is typically given by the BZ day-ahead price;
- **LTTRs markets.** Transmission rights are issued long-term by the TSOs at the different borders in Europe, to allow:
  - the hedging of the price differential between (neighbouring[29]) BZs, to support bilateral cross-border transactions where no physical interconnection capacity is allocated explicitly; and
  - the transfer of the effect of hedges obtained in any given BZ to a different (neighbouring) BZ (cross-zonal hedging).

Other long-term instruments, covering the risk related to the variability of the price differential between a BZ price and the price of a hub, are also available in specific regions (EPADs in the Nordic and Baltic regions and CCCs in Italy).

1.1 The current model for electricity forward markets

1.1.1 Product design

Electricity derivatives traded in Europe include:

- **Financially-settled futures.** These are contracts where the buyer agrees to exchange with the seller the difference between the futures price and the hourly electricity spot price, over a predetermined period of time in the future (the 'delivery period'). Futures contracts are typically standardised and traded on exchanges. They are marked-to-market, i. e. at any point in time there is only one futures contract for each product and delivery period. Parties buying or selling a futures contract do not have to pay/receive the futures price at the time they enter into the contract; they only need to post a margin (the 'initial margin'), to cover future variations in the futures price. As the futures price then changes, parties holding positions in such a contract are required to increase or allowed to decrease their margin payments. At maturity, the futures price converges to the spot price and, therefore, no further final payment is envisaged. In the course of the delivery period, the differential between the hourly electricity spot price and the futures price is settled by the exchange.
- **Physically-settled forwards.** These are contracts where the seller agrees to deliver to the buyer a certain quantity of electricity over a certain period of time (the 'delivery period') at a predetermined price (the forward price), which the buyer commits to pay. Physically-settled forwards have the same economic value of the corresponding futures as their value is determined as the difference between the forward price and the spot price at the time of delivery. However, their physical nature implies that these contracts are not market-to-market and the forward price is paid by the buyer to the seller at maturity. For this reason, physically-settled contracts feature higher guarantee requirements compared to financially-settled futures. Forwards contracts are typically not standardised, at least not to the same extent as futures contracts, and are not quoted on an exchange, but rather traded 'over the counter', with the possible involvement of brokers.

28 The churn rate measures how many times a forward is exchanged before entering into delivery. High churn ratios indicate mature and liquid markets featuring an efficient price discovery activity.

29 Depending on the format of LTTRs, they might be combined to provide hedging across multiple borders and therefore between non-neighbouring BZs.

- **Financially-settled options.** These are contracts under which the buyer has the right to buy (for 'call' options) or to sell (for 'put' options) an electricity futures contract at a predetermined price (the 'strike price'), at a predetermined date before the futures' delivery period (the 'expiry date' of the option). Therefore, the option holder is not required to trade electricity as the underlying future is financially settled. However, a financially-settled option provides the holder a hedge against high electricity prices (for 'call' options) or low electricity prices (for 'put' options) for, respectively, buying or selling electricity during the futures' delivery period.

In all European markets, electricity derivatives are built upon the same 'underlying' type of commodity, namely the electricity in the relevant national spot market (hub). In practice, this implies that the settlement of futures is performed against the day-ahead price of electricity, whereas the delivery under forward contracts takes place via nominations in the day-ahead market platforms. In the case of options, the underlying asset is given by the corresponding futures, which is, in turn, built upon the day-ahead price index.

1.1.2 European commodity forward markets

At present, futures are listed for all BZs in Europe, including countries that are not part of the Union but are interconnected and coupled with EU markets (such as UK, Switzerland and Norway).

Financially-settled futures are the reference product for trading and hedging across Europe. The European Energy Exchange (EEX) is the European largest marketplace for the exchange of power derivatives, listing futures on markets across the entire of Europe (see Figure 8). EEX also lists electricity options for the main European markets (Germany, France, Spain and Italy)[30].

Additional marketplaces for electricity derivatives include:

- Nasdaq, which lists futures for the Nordic region, as well as German and French futures[31];
- The Intercontinental Exchange (ICE), which lists futures for Germany, the Baltic region, Italy, France, the UK, Netherlands, Belgium, Austria, Switzerland and Spain, as well as options for the German, French and Italian markets[32];
- The Operador do Mercado Ibérico de Energia – Pólo Português (OMIP), which lists futures for the Spanish, Portuguese, German and French markets, as well as options and physically-settled forwards for the Spanish and Portuguese markets[33]; and
- The national exchanges in Italy (GME), Greece (HEnEx), Austria (Wiener Boerse) and Hungary (HuDEx), which list futures contracts for their respective national markets (in the case of Italy, physically-settled forwards).

In what follows, the focus is on the role of financially-settled futures in the European forward markets. These represent by far the most liquid products, but similar considerations apply also to physically-settled forwards that present the same payoff structure.

Given their payoff structure, the value of financial futures is determined as the expected average spot price of electricity during the delivery period. Otherwise stated, at any given point in time, the price of the futures reflects the expectation of the market regarding the spot electricity prices over the delivery period.

In this overview, the focus is not placed on electricity options as (contrary to the LTTR market), the liquidity of these instruments is still limited.

30 See here.
31 See here.
32 See here.
33 See here.

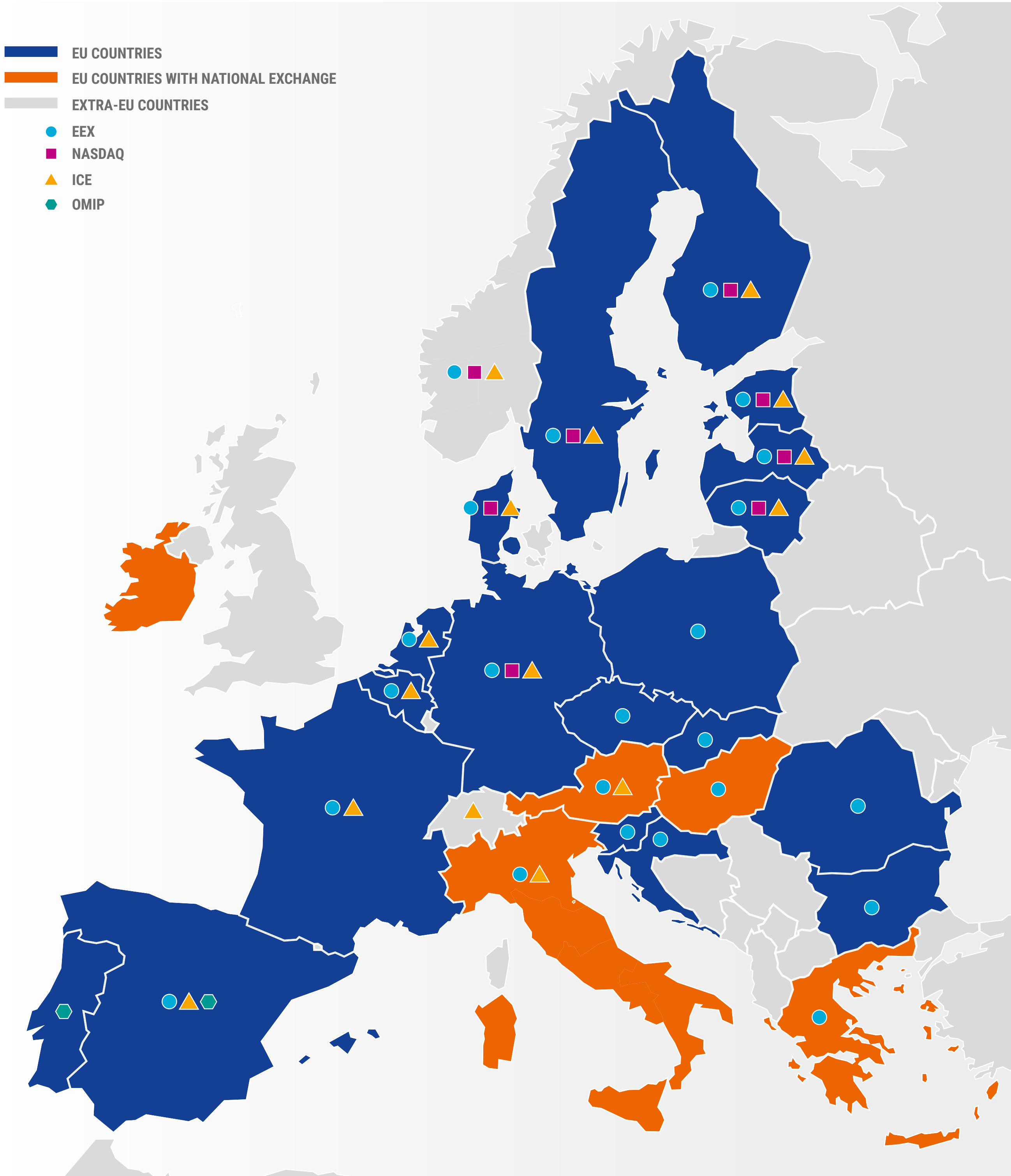

Figure 8 – Financial-settled futures listed in Europe

1.2 The current model for transmission rights markets

In Europe, different products are in place for market participants to nominate physical transmission between neighbouring BZs or to hedge the price difference either between two neighbouring BZs or the local price and a regional price.

Those products can be broadly divided in two categories: LTTRs and CfDs or Futures. The main difference between these categories is whether or not TSOs are the counterparty.

1.2.1 TSOs as counterparty – LTTRs

In central Europe, two kinds of LTTRs are currently issued: physical transmission rights (PTRs) in connection with the 'Use it or sell it' principle and FTR Options. The JAO hosts a pan-European platform (i. e. the Single Allocation Platform) that performs the explicit allocation of LTTRs on all European borders and for all maturities. At present, FTR Options are allocated on 26 borders and PTRs are allocated on 7 borders for each direction, via auctions spanning monthly, quarterly and yearly maturities. Figure 9 shows on which borders LTTRs are allocated at JAO.

A market participant receiving a PTR in an auction can either use it or sell it. By using it, the market participant nominates its PTRs and hence can trade energy in a neighbouring BZ via OTC markets or power exchanges as well as meet physical positions in two BZs. If a market participant chooses to sell it, the PTR holder makes no use of the option to nominate its rights and receives the day-ahead price difference of the respective BZs for the contracted capacity if the price difference is positive or 0 if the difference is negative (same effect as an FTR Option).

A market participant holding an FTR Option automatically receives the day-ahead price difference multiplied by the contracted capacity or 0 € without the possibility to physically use the transmission right.

The number of participants at auctions hosted by JAO has been increasing over the years: in the period 2019–2021, 224 market participants have actively participated in the LTTR auctions.

The LTTR market displays a relatively high degree of concentration: the first 27 participants (12 % of the total) hold more than 75 % of the allocated volumes, and the first 11 (4.9 % of the total) hold more than 50 % of the market. Furthermore, the secondary market for LTTRs appears to be stagnant as only 2 % of capacity allocated through monthly auction was re-sold by market participants.[34]

1.2.2 TSOs are not a counterparty: Contract for Differences and Futures

CfDs are another instrument used in Europe to hedge against price differences.

In the Nordic and Baltic (Latvia and Estonia) market, Nasdaq offers EPADs Futures. EPADs provide the option to hedge the price in one BZ against an area price, whereas the area price represents the price occurring without constraints in the transmission grid of the respective BZ. It is important to stress that EPADs are not issued by TSOs and TSOs have no involvement in their allocation process. In fact, EPADs are 'normally-traded' financial products, and the congestion rent is not used to back up payments under EPADs.

In Italy, multiple zones are established, and generators are remunerated at their corresponding zonal price. However, as all consumers pay a single price across the country, the Prezzo Unico Nazionale (PUN), a virtual 'hub' is established featuring no generation and containing all the Italian consumption. When contracting with electricity buyers at PUN, generators are exposed to the price differential between their zonal price and the PUN. To hedge this risk, the TSO issues and allocates zone-to-hub FTR Obligations indexed on the price spread *PUN-Pzonal* (these are termed Copertura contro il rischio di volatilità del Corrispettivo di assegnazione della Capacità di trasporto, CCCs). Although there is no physical interconnection between the BZs and the 'virtual' PUN hub, the *PUN-Pzonal* spread still represents a 'commercial' congestion rent that is collected by the market operator when clearing the day-ahead market. This rent is then used to cover payments under the CCCs. Therefore, no risk is placed on the TSO to back up payments of CCCs.

34 The secondary market of LTTRs is further assessed in sub-section 4.3.

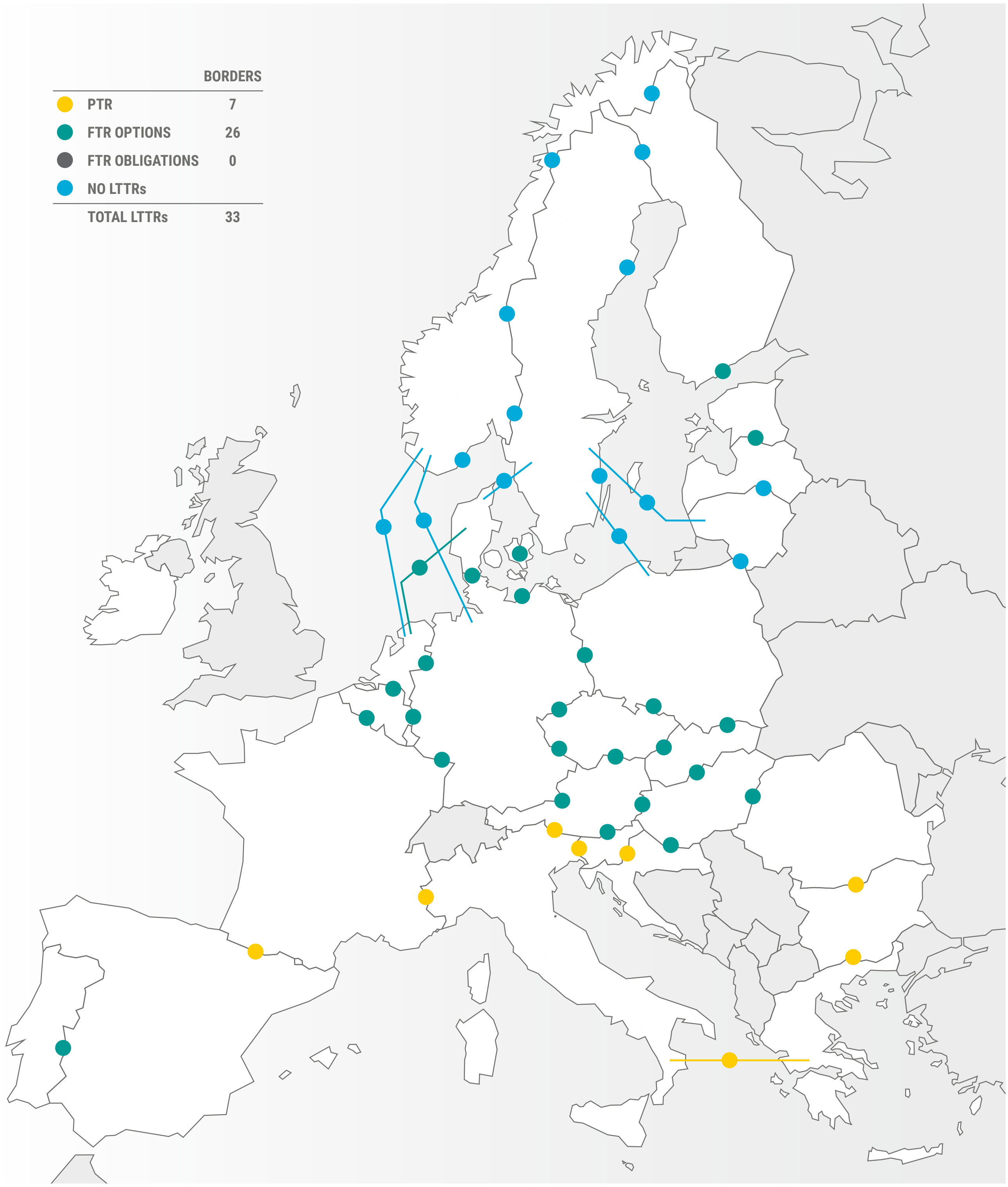

Figure 9 – PTRs and FTRs expected in Europe (2023)

Annex 2: The Application of Financial Market Regulation to TSOs

Under the current financial market regulation, essentially Directive 2014/65/EU[35] (MIFIDII) and in particular Section C, point (5), in Annex I thereto[36], FTRs are classified as financial instruments and, therefore, their trading is subject to the provisions in the same Directive, in Regulation (EU) No 648/2012[37] (EMIR) and in Regulation (EU) No 600/2014[38] (MIFIR).

However, Article 2(1)(n) of MIFID II provides that the same Directive does not apply to 'transmission system operators as defined in Article 2(4) of Directive 2009/72/EC or Article 2(4) of Directive 2009/73/EC when carrying out their tasks under those Directives, under Regulation (EC) No 714/2009, under Regulation (EC) No 715/2009 or under network codes or guidelines adopted pursuant to those Regulations, any persons acting as service providers on their behalf to carry out their task under those legislative acts or under network codes or guidelines adopted pursuant to those Regulations, and any operator or administrator of an energy balancing mechanism, pipeline network or system to keep in balance the supplies and uses of energy when carrying out such tasks. That exemption shall apply to persons engaged in the activities set out in this point only where they perform investment activities or provide investment services relating to commodity derivatives in order to carry out those activities. That exemption shall not apply with regard to the operation of a secondary market, including a platform for secondary trading in financial transmission rights'[39].

35 Directive 2014/65/EU of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU.

36 'Options, futures, swaps, forwards and any other derivative contracts relating to commodities that must be settled in cash or may be settled in cash at the option of one of the parties other than by reason of default or other termination event'.

37 Regulation (EU) No 648/2012 of the European Parliament and of the Council of 4 July 2012 on OTC derivatives, central counterparties and trade repositories.

38 Regulation (EU) No 600/2014 of the European Parliament and of the Council of 15 May 2014 on markets in financial instruments and amending Regulation (EU) No 648/2012.

39 The references to the definition of the electricity TSOs and to their activities in the legislative acts in the Third Energy Package should now be understood as references to the legislative acts in the 2019 Clean Energy for All Europeans Package.

To assess whether this exemption applies to the issuing and primary allocation of FTR Obligation by TSOs, the following conditions should be verified:

- the issuing and primary allocation of FTR Obligation can be considered as activities carried out by TSOs under the energy sector legislation. In this respect, it is to be noted that the FCA Regulation, in Article 30(1), mandates 'TSOs on a bidding zone border […] to issue long-term transmission rights unless the competent regulatory authorities of the bidding zone border have adopted coordinated decisions not to issue long-term transmission rights on the bidding zone border'. The issuing of LTTRs, including FTR Obligations, is therefore among the statutory tasks of TSOs (unless otherwise directed by their national regulators); and
- the issuing and allocation of LTTRs, including FTR Obligations[40], does not constitute 'the operation of a secondary market, or of a platform for secondary trading'. In this respect, although MIFID II does not contain a definition of secondary markets, all trading venues defined in that Directive[41] have the common feature of being 'multilateral systems', bringing together 'multiple third-party buying and selling interests'[42] in financial instruments.

Therefore, on the basis of the considerations presented above, it can be concluded that the role of the TSOs envisaged in issuing and allocating LTTRs is not subject to the financial market regulation. The same applies if TSOs assign this role to a JAO.

Instead, if TSOs were to trade FTRs in secondary markets, they would engage in trading activities within the scope of the financial market regulation and would be subject to the provisions of such regulation.

40 The opportunity of netting FTR Obligations issued on the same market-area border for the same delivery period, but in opposite directions, does not affect nor change the one-to-many nature of the auctions for the primary allocation of these FTRs.

41 'Regulated markets', 'multilateral trading facilities' and 'organised trading facilities'.

42 Article 4(1)(21) to (23) of MIFID II.

Annex 3: Evaluation Table (Summary)

	CRITERIA	APPROACH 1: FTR OPTIONS WITH ADJUSTMENTS	APPROACH 2: FTR OBLIGATIONS	APPROACH 3: PURELY FINANCIAL FORWARD MARKETS
1	**Liquidity**	› With the new allocation framework, access to liquidity is improved, which promotes competition and prevents hoarding of capacities. › Illiquid BZs get access to liquidity of more liquid neighbouring BZs. › Market has no incentives to further develop liquidity in their home BZs.	› With FTR Obligations, 'synthetic' futures can be created for illiquid BZs. › FTR Obligations issued in opposite directions on the same BZ border can be netted out. This allows more capacity to be offered towards the market participants compared to the PTRs/FTR Options.	› Liquidity is not split in different markets. No liquidity out-migration from smaller illiquid zones to already very liquid zones. › The market is free to develop the products which best fit their purposes. › To have a functioning purely financial market, a certain amount of liquidity needs to be in the BZs.
2	**The LTTR undervaluation**	› The more occurrences of auctions and the increase of number of products issued increases attractiveness and thus higher LTTR prices. › The introduction of a continuous secondary market might have a positive effect on the undervaluation. › The introduction of a minimum auction price ensures that undervaluation does not increase above a certain level. › In the event one BZ has an illiquid electricity forward market, FTR Options may not necessarily solve the issue of undervaluation, because if participation in auctions is limited the price could still form below the efficient level.	› The pricing of FTR Obligations is immediate in the event both BZs feature a liquid electricity futures market. › In case one BZ has an illiquid electricity forward market, FTR Obligations may not necessarily solve the issue of undervaluation in the short term, because if participation in auctions is limited the price could still form below the efficient level. › FTR Obligations allow for the definition of 'synthetic' futures that support the development of liquidity in currently illiquid BZs. As liquidity develops, it is expected that an efficient price level is reached progressively. › The introduction of a minimum auction price would support the competitiveness of the market and ensures that undervaluation does not increase above a certain level.	LTTRs are not issued anymore, which means that no welfare transfer from end consumers to some market participants take place.
3	**Secondary market**	› Continuous secondary market for FTR Options will support the liquidity of the market. › However, it will be challenging to design a secondary market for FTR Options with low entry barriers for market participants	As FTR Obligations are effectively financial futures, it can be expected that the secondary market will become more active. FTR Obligations would be continuously traded, after being issued from TSOs.	Not needed as there are no LTTRs, but the market can provide a market for products providing hedging opportunities against the volatility of price spreads, which already happens now.
4	**Collaterals**	No changes in the current collateral scheme necessary.	Due to its symmetrical nature, the implementation of FTR Obligations requires changes in the collateral scheme (either higher collaterals or mark-to-market collateral mechanism).	› One layer of collaterals (for LTTRs) not needed anymore and reduces overall complexity. › Collaterals' issue only affects commodity markets. › Harmonisation of collaterals' scheme yet to be further assessed.
5	**Hedging between not neighbouring BZs**	As FTR Options are not equivalent to electricity futures, it is more challenging for market participants to hedge between not neighbouring BZs.	Merging a number of zone-to-zone FTR Obligations enables market participants to hedge more easily between not neighbouring BZs.	Can be achieved by buying a future in one zone and selling it in the other (product harmonisation of futures could contribute to this).
6	**Costs on ensuring firmness**	The level of firmness as provided in 4.6 should be reflected in the decision on the design of a future forward market.	The level of firmness as provided in 4.6 should be reflected in the decision on the design of a future forward market.	No costs to ensure firmness as TSOs do not provide financial products.

	CRITERIA	APPROACH 1: FTR OPTIONS WITH ADJUSTMENTS	APPROACH 2: FTR OBLIGATIONS	APPROACH 3: PURELY FINANCIAL FORWARD MARKETS
7	**Future proof for RES integration**	No changes to the current market model.	Slight benefit related to the improvements in the secondary markets, which provide more flexibility.	› By giving the freedom to the market to define their own fit-for-purpose products, it is expected there will be a wider range of financial products which are more suitable for RES. › Correct pricing signal as risks are kept with the risk owners and not shifted towards TSOs and therewith socialised.
8	**Risk profile of MPs**	› FTR Options with adjustments would still provide market participants with good profit maximisation possibilities. › Forecasting of FTR Options prices is more complex for market participants as they cannot directly compare them with the price of futures contracts.	› Forecasting of FTR Obligations prices becomes easier for market participants as they are directly comparable with the price of futures contracts. › Under FTR Obligations, market participants are obliged to pay the market spread to TSOs in the event it is negative. Hence, market participants are exposed to higher price risks, but only if they do not use the FTR Obligation to create synthetic futures.	› Perceived risk/reward could be too high for any commercial counterparty to offer cross-zonal products. › Not having access to aptly priced cross-zonal hedging could reduce forward hedging opportunities in inherently illiquid BZs or limit forward trading to large players only. › Market would develop better suited products to handle the risks. › Financial products adapting more swiftly to the market conditions.
9	**Risk profile of TSOs**	› The procedure of long-term capacity calculation is very time and resource consuming. Furthermore, it is currently not clear how capacity shall be calculated for more than one year in advance. › With LTA inclusion, the allocated long-term capacity has an effect on the physical grid. An alternative to LTA inclusion may be considered to avoid this effect.	› The procedure of long-term capacity calculation is very time and resource consuming. Furthermore, it is currently not clear how capacity shall be calculated for more than one year in advance. › TSOs are exposed to higher risks if market participants are not able to pay the negative market spreads. This risk can partly be reduced by introducing a clearing house. › With LTA inclusion, the allocated long-term capacity has an effect on the physical grid. An alternative to LTA inclusion may be considered to avoid this effect. › LTFBA project might be impacted by switching to FTR Obligations.	› No risks for TSOs as they are no longer involved in the forward market. › Capacity calculation can be done for the timeframes where the status of the grid can be predicted the best.
10	**Risk profile of end consumers**	› End-consumers could benefit through access to hedging opportunities. › The additional redispatching costs and reimbursement payments will translate into grid tariffs. An alternative to LTA inclusion may be considered to avoid this effect.	› Due to the symmetric nature of FTR Obligations, money-making gets less attractive to market participants, which can result in higher benefits for market participants who really need to hedge. › The additional redispatching costs and reimbursement payments will translate into grid tariffs. An alternative to LTA inclusion may be considered to avoid this effect.	› End consumer is no longer affected by firmness costs or undervaluation of LTTRs. › However, in illiquid BZs, the absence of cross-zonal capacity could limit the access to hedging opportunities for end-consumers.

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
BZ	Bidding Zone
CCR	Capacity Calculation Regions
CEER	Council of European Energy Regulators
CfD	Contract for Difference
CI	Congestion Income
DSO	Distribution System Operator
EC	European Commission
ENTSO-E	European Network for Transmission System Operators in Electricity
EPAD	Electricity Price Area Differentials
FCA	Forward Capacity Allocation
JAO	Joint Allocation Office
LTFBA	Long-Term Flow-Based Allocation
LTTR	Long-Term Transmission Rights
MiFID	Markets in Financial Instruments Directive
NEMO	National Electricity Market Operator
NRA	National Regulatory Authorities
OTC	Over The Counter
PPA	Power Purchasing Agreements
REMIT	The Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable Energy Sources
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
Z2Z	Zone-to-Zone
Z2H	Zone-to-Hub

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