# D2.2 Implementation Status and Market Focused Diagnosis of the Target Model

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## 1 Nomenclature: List of Acronyms

| | |
|---|---|
| ACER: | Association for the Cooperation of Energy Regulators |
| APdw: | Average Price of activated downward reserves |
| APup: | Average Price of activated upward reserves |
| APCA: | All Party Cooperation Agreement |
| ATC: | Available Transfer Capacity |
| BZ: | Bidding Zone |
| BRP: | Balance Responsible Party |
| BSP: | Balancing Service Provider |
| BZB: | Bidding Zone Border |
| CaCM: | Capacity Allocation and Congestion Management Network Code |
| CASC: | Capacity Allocation Service Company |
| CCR: | Capacity Calculation Region |
| CEE: | Central Eastern Europe Region |
| CEER: | Council of European Energy Regulators |
| CoBA: | Coordinated Balancing Areas |
| CRM: | Capacity Remuneration Mechanism |
| CWE: | Central Western Europe Region |
| CSE: | Central Southern Europe Region |
| CZC: | Cross Zonal Capacity |
| EB: | Electricity Balancing Network Code |
| EC: | European Commission |
| EFET: | European Federation of Energy Traders |
| ENTSO-e: | European Association of Transmission System Operators for Electricity |
| ERCOT: | Electric Reliability Council of Texas |
| ERGEG: | European Regulators Group for Electricity and Gas |
| ERI/RI: | Electricity Regional Initiative |
| Eurelectric: | European Association of Electric Utilities |
| EU: | European Union |
| FB: | Flow Based |
| FCA: | Forward Capacity Allocation Network Code |
| FCP: | Frequency Containment Process |
| FCR: | Frequency Containment Reserves |
| FG: | Framework Guidelines |
| FTR: | Financial Transmission Right |
| FRP: | Frequency Restoration Process |
| FRR: | Frequency Restoration Reserves |
| FUI: | France-UK-Ireland region |
| IEM: | Internal Electricity Market of the EU |
| IFA: | Interconnection France-Anglaterre (French) |
| IT: | Information Technology |

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| LFC: | Load Frequency Control |
| LFCR: | Load Frequency Control and Reserves |
| LTTR: | Long Term Transmission Rights |
| MCO: | Market Coupling Operator |
| MIC: | Minimum Income Condition order |
| MPdw: | Marginal Price of activated downward reserves |
| MPup: | Marginal Price of activated upward reserves |
| MPAD: | Day Ahead Market Price |
| NC: | Network Codes |
| NEMI: | Nominated Electricity Market Operator |
| NEMO: | National Electricity Market Operator |
| NP: | Net Position |
| NRA: | National Regulatory Authority |
| NTC: | Net Transfer Capacity |
| NEW: | North Western Europe Region |
| PCA: | Power Exchange Cooperation Agreement |
| PCR: | Price Coupling of Regions |
| PTDF: | Power Transfer Distribution Factor |
| PTR: | Physical Transmission Right |
| PUN: | National Single Price (in Italian) |
| PX: | Power Exchange |
| RAM: | Remaining Availability Margin |
| RES: | Renewable Energy Sources |
| RR: | Replacement Reserves |
| RRP: | Reserve Replacement Process |
| SEE: | South Eastern Europe Region |
| SPA: | Single Price Area |
| SWE: | South Western Europe Region |
| TM: | Target Model |
| TR: | Transmission Right |
| TSO: | Transmission System Operator |
| UIOSI: | Use It Or Sell It rules |
| VPP: | Virtual Power Plant |

# 1 Executive summary

In the last ten years the penetration of renewable generation in power systems in Europe has increased very significantly. Power production will have to be dominated by RES generation in the coming decades in order to achieve environmental objectives set in the 2020, 2030 and 2050 time frames within the EU. The Target Model (TM) developed by the European Commission (EC) in cooperation with ENTSO-e and ACER represents an attempt to make the penetration of large amounts of renewable generation compatible with the satisfactory functioning of power systems in Europe from a techno-economic point of view.

The TM comprises a set of documents, the Network Codes (NCs), or framework guidelines, related to different aspects of the functioning of the system. Among other issues, NCs deal with the design of market required to achieve a well functioning IEM. NCs focused on the functioning of markets are the so-called Market NCs. Together with Connection and Operation Codes, they make the whole set of rules, and principles, developed to increase the efficiency in the functioning of the European interconnected system.

## 1.1 Description of NCs

Market NCs aim to achieve an efficient functioning of markets currently developed at European level. Three Market Codes exist:

- The Capacity Allocation and Congestion Management (CaCM)
- The Forward Capacity Allocation Code (FCA)
- The Electricity Balancing Code (EB)

The CaCM Code (or Binding Guidelines) cares about three main interrelated issues:

- The computation of available interconnection capacity to be allocated to transactions taking place between each pair of bidding zones (or zones defined for congestion management and electricity pricing reasons in the day-ahead time frame);
- The allocation of interconnection capacity and associated pricing in the day-ahead time frame;
- And the management of congestion and dispatch of energy and transmission interconnection capacity in the intra-day time frame.

The computation of available interconnection capacity can take place according to two either of two main methods: either in a coordinated way among all bidding zones (Flow-based) or predefining the amount of capacity on each likely to get congested link to be allocated to transactions between each pair of bidding zones (Coordinated Net transmission Capacity determination). The Flow-based scheme results in a more efficient allocation of capacity and therefore is preferred except in radial networks, where applying it may not be necessary.

The congestion management and pricing in the day-ahead time frame is organized in the form of centralized auctions taking place for each hour of the whole next day where energy and transmission interconnection capacity among bidding zones are allocated jointly. The mechanism implemented has been termed Price-Coupling and results in a marginal price for each bidding zone. Bidding zones have been defined within each country (in the majority of countries there is a single one) and they are expected to be updated periodically. The algorithm used for the matching of bids in the day-ahead is called Euphemia and it is very flexible, accepting almost any kind of bid. Many different types of constraints associated with bids have been accommodated in this algorithm.

Capacity allocation and congestion management in the intra-day time frame is taking place primarily, though a continuous trading scheme similar to the one in place in Stock-Exchanges. Bids for the purchase and sale of electricity are allocated interconnection capacity according to the prices offered (price in bids for purchase must be higher than in bids for sale that are matched with the former) and the amount of interconnection capacity available. This is possibly combined with intraday-auctions at times when problems of liquidity advise organizing them.

The Forward Capacity Allocation Network Code establishes common rules for the establishment of a common methodology and process for determining the Cross Zonal Capacity and its subsequent allocation in the long-term. Forward capacity allocation shall be implemented on all those bidding zone borders where competent National Regulatory Authorities (NRA) determine that market agents are in need of instruments like these to manage the risk associated with the volatility in the price to be paid to access the grid to inject power in a certain bidding zone and retrieve it in another one.

In particular, the FCA establishes common rules and guidelines around:

- Long-term transmission capacity determination
- The single allocation platform for cross-border capacity rights
- The long-term transmission capacity products and the associated firmness
- Homogenize nomination rules for physical transmission rights
- Others: financial requirements and fallback procedures, publication of information and secondary trading

Mechanisms for the determination of transmission capacity are the same as in the day-ahead time frame. There must be a single platform for the initial allocation of transmission rights. Rights can be subsequently traded in auctions or bilaterally among agents. Products that can be issued are physical transmission rights, financial rights as obligations, and financial rights as options. Curtailment of these rights is subject to compensation that shall depend on the time of curtailments (after or before the nomination deadline).

The main purpose of the EB NC is achieving a well functioning, integrated, balancing market in the IEM. The design of the market and its implementation is aimed at making smooth progress in the integration process. Then, this process is expected to go through several stages from the integration of control areas for imbalance netting, whereby imbalances would be computed in larger areas than the current control ones, to the creation of common merit order lists, which involves having all balancing bids considered together and being dispatched according to the prices offered in them, its features, and available interconnection capacity among areas.

The NC is providing general guidelines while it leaves many issues open, from the definition of the trading time units to that of the trading period, or definition of the gate closure time; going through the definition of products and the imbalance settlement rules. Regarding this last point, both single and dual pricing are considered options, and marginal pricing is not considered the only option. The time frame of bids submitted is not defined in a harmonized way.

## 1.2 The process of deployment of the IEM

The European energy regulators have been working together for many years to promote regional cooperation and the integration of energy markets. The Regional Initiatives (RIs), launched by the European Regulators Group for Electricity and Gas (ERGEG) in 2006, aimed at bringing together national regulatory authorities (NRAs), transmission system operators (TSOs) and other stakeholders in a voluntary process to advance integration at the regional level as a step towards the creation of a well-functioning Internal Energy Market (IEM). The RIs represent a bottom up approach to the completion of the IEM. Seven regional initiatives have been defined, which are based in seven European regions partly overlapping: Central West European RI, North (North Western, initially) European RI, France-UK-Ireland RI, the Baltic RI, the Central South RI, the South West RI, and the Central East RI.

The EU Energy Work Plan for 2011-2014 in Electricity is constituted from four cross-regional roadmaps focusing on the implementation of the target models for CaCM across Europe and seven regional roadmaps complementing and detailing the cross-regional roadmaps and focusing on other important dimensions for the completion of the Internal Electricity Market. Each cross-regional roadmap is dedicated to one particular timeframe or topic:

- Implementation of a single European price market coupling model;
- Implementation of a cross-border continuous intraday trading system across Europe;
- Implementation of a single European set of rules and a single European allocation platform for long and medium-term transmission rights;
- Implementation of fully coordinated capacity calculation methodologies and particularly the flow-based allocation method in highly meshed networks.
- Integration of Electricity Balancing markets

Each of the RIs defined is aiming to make progress jointly, in a coordinated way, in the deployment of Binding Guidelines. There are several reports issued by ACER and CEER providing information on the progress made in the implementation of the IEM:

- ERI Quarterly Reports: Published every quarter of a year.
- Regional Initiatives Status Review Reports: These are published annually.
- Market Monitoring Reports: these are also published annually.

The level of implementation of NCs and the associated regulation making the TM in the several RIs and countries in Europe is being quite heterogeneous, with the most advanced region in the deployment of the TM and the IEM being the North-Western and South-Western RIs.

## 1.3 Assessment of the TM

As mentioned above, the TM being developed by the EC in cooperation with regulators and TSOs in Europe represents a first attempt to adapt markets to the new system needs. Relevant stakeholders have managed to develop short-term energy markets that are gradually evolving towards a fully-integrated, efficient pan-European one through the joint implicit auctioning of energy and transmission capacity in the day-ahead time frame. There are still aspects of short-term markets that need to be worked out in order for their functioning to be fully satisfactory, but the general design of these markets seems to be sound. Large progress has already been made in the implementation of day-ahead market coupling, which has allowed the coordinated dispatch of energy and interconnection capacity among systems in most of Western and Central Europe.

Aspects in short term markets that still need to be refined include the definition of an appropriate level of granularity of the network model considered in the dispatch (currently, in the majority of Europe, each national system is considered a single node in the dispatch algorithm), and the update of this network model; and the timing of energy markets, which relates, among other things, with the definition of the appropriate sequence of centralized auctions and continuous markets matching the needs of market agents.

In the long term, traditionally, transmission capacity products have been sold and subsequently traded to allow agents to manage the risk associated with the volatility in the price of access to the transmission grid. This, of course, is needed and is being already considered within the TM in FCA NCs. However, together with long term transmission capacity markets, other long term markets may need to develop. These potentially include long term capacity, clean energy and even balancing markets. These may be needed for the appropriate amount of the corresponding products to be deployed. Otherwise, investment incentives may not be strong enough to trigger the installation of generation, demand and network assets required for the supply of these products.

A large number of national systems in Europe are already implementing capacity remuneration mechanisms, also called adequacy systems. However, the deployment of firm capacity in Europe should take place at a reasonable cost and not increase substantially the cost of operation of the system as well. This requires that solutions to contract capacity, if implemented, are applied in a coordinated way, thus allowing competition to take place among potential firm capacity providers all over Europe. Besides, remuneration schemes applied in long term capacity markets should not interfere with efficient signals in the short term. This should be a first priority of the Commission.

As far as the supply of clean energy is concerned, this should be guaranteed in order to comply with environmental objectives. The ability of currently existing energy markets to provide strong enough incentives to RES operators to install large enough amounts of this type of generation is dubious. Energy contracted in current markets does not need to be clean and the value of it at times when RES energy is available for its sale may not suffice to pay back investments in RES generation capacity. Thus, specific mechanisms may need to be implemented to contract the supply of clean energy. Long term supply schemes may be able to cover the increase in the costs of market agents associated with the provision of clean energy while allowing these agents to stabilize their revenues already in the long term. However, the supply of clean energy should in any case be arranged in a way that results in the lowest cost possible for the system. It should be the most efficient generators able to supply the required amount of clean energy both in the short and in the long term the ones that this product should be contracted with. And again, signals resulting from these markets should not interfere with efficient short term, operation, signals.

Even the contracting of some balancing products in the long term may be considered, though the need for these remains to be seen.

Lastly, in the very short term, a perfect match between power supply and demand must be ensured at any time and it must take place in the most efficient way possible. Balancing markets have long existed in Europe, but their functioning could be improved in several ways. Some of the changes to be made to balancing markets have to do with the need to achieve the integration of national ones. Others have to do with the need to integrate other resources than traditional, conventional, generation in them, like energy consumers, and RES generation, both on the supply and on the demand side.

In order to achieve the integration of national balancing markets, issues to address include the harmonization of methods, or algorithms, used to trade balancing products and the harmonization of the features of balancing products themselves. This should increase the level of liquidity in the market and would avoid losses of efficiency from lacks of coordination among the contracting of balancing products in the several areas of the system. Besides, access to interconnection capacity among systems in balancing markets should also be carefully thought in order to allow for international trade to take place while not interfering badly with other markets.

The participation of RES generation and demand in balancing markets should be achieved by abolishing unnecessary barriers to this (like minimum size ones, or prohibitions for them to aggregate into large entities like VPPs). Besides, authorities should promote the implementation of an efficient market scheme whereby prices earned for the provision of balancing services corresponds to their value, while payments reflect the responsibility of agents (BRPs) in balancing costs.

## 2 Introduction

This second report of the WP2 of the Market4RES project focuses on the diagnosis of the Target Model (TM) developed by the European Commission (EC), Transmission Systems Operators (ENTSO-E) and Regulators (ACER). The role of the TM is to ensure an effective and efficient functioning of traditional electricity markets in compliance with economic efficiency, system security, and environmental policy objectives. Results of these objectives are, on the one hand, the deployment of large amounts of RES generation and, on the other hand, the use of all types of resources available in the system. These challenges have already been highlighted in the deliverable D2.1 of the Market4RES project.

The TM comprises a set of initiatives for the development of efficient energy and balancing markets at the European level. These markets will be complemented by a framework for the negotiation of transmission capacity products in the long term. These initiatives have been materialized in the drafting of Network Codes (NCs) describing the main design features of these markets. Following the third energy package, NCs must go through different stages of discussion and elaboration to end up with the definition of binding guidelines issued by the EC. These binding guidelines must be transposed into changes to existing markets in European countries leading to an improvement of their functioning and finally their integration at the EU level.

As they are developed both successively and in parallel, different NCs are in different stages of "maturity". Therefore, their assessment in their current state is not always an easy task. However, given the ambitious goal of reforming markets in Europe through the implementation of NCs, it is of utmost importance that the ability of markets to deliver the expected results in the TM framework is ascertained. An effective and efficient functioning of electricity markets will not only condition the energy sector, but the whole economy in Europe.

It should be noted that the assessment made in this report is of a qualitative or conceptual nature. This is complemented by quantitative analyses of the functioning of specific markets. These Case studies conducted in the frame of the task 2.3 refer to specific areas of the European system and are reported in deliverable D2.3. Based on main pending market developments identified in this report, and the quantitative analyses in D2.3, WP3 defines design options for these market developments and assesses them from a conceptual point of view. Then WP5 carries out a quantitative assessment of the most promising design options and identified the best suited ones for their implementation. The implementation of these is finally discussed in WP6.

This report provides a description of NCs currently under development in section 3 and section 4. Then, the process of development and implementation of NCs is discussed in section 5. Section 6 makes the core of this report, since it describes the assessment of the TM performance over several time frames: long, short, and very short term. Lastly, section 7 concludes the report.

## 3 The Network Codes: general framework

### 3.1 Network Codes as a necessary tool to achieve a well-functioning IEM

As part of the EU third energy package, the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) were established.

ACER was mandated[1] to propose Framework Guidelines, constituting the basis for ENTSO-E to develop legally binding Network Codes[2] (NCs) for cross-border network and market integration issues. Member States have the right to establish additional national network codes which do not affect cross-border trade.

This way, NCs aim at providing harmonized rules for access and exchanges of electricity in the Internal Energy Market (IEM). The drafting of those documents involves a large procedure implicating not only ACER and ENTSO-E but also the European Commission (EC). In particular, following ACER's recommendation, each code is submitted to the EC for approval through the Comitology process, to then be voted into EU law and implemented across Member States. By this process, the content of each NC has the same status as any other European Regulation, governing all electricity market transactions with a cross-border impact.

These rules for electricity are under development since 2011, each code was supposed to ideally take approximately 18 months to complete. However, for different reasons, this development process is being delayed.

### 3.2 The three interrelated areas covered by the Network Codes

ENTSO-E is currently working on ten network codes covering three interrelated areas (see also http://networkcodes.entsoe.eu/):

- **Connection Codes:** The rules setting out the minimum requirements for the connection of generators of all sizes and the connection of large consumers and users to the transmission grids. The Connection Network Codes include:
    - Requirements for Generators
    - Demand Connection
    - High Voltage Direct Current Connections

- **Operational Codes:** The set of rules and regulations governing how these systems are operated in such a way that the electricity system is kept reliable, sustainable and stable.

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[1] According to Regulation (EC) No 713/2009a
[2] According to Regulation (EC) No 714/2009b

This involves the rules concerning the operation in real time and the requirements to do so. The Operational Network Codes are:

- Operational Security
- Operational Planning & Scheduling
- Load Frequency Control & Reserves
- Emergency and Restoration

- **Market Codes:** The common rules that shape the design of the pan-European electricity market. This rules focus on both electricity and capacity (the available capacity of transmission networks to transport electricity) traded across Europe. There are three market-related Network Codes:
  - Capacity Allocation & Congestion Management (CACM)
  - Electricity Balancing
  - Forward Capacity Allocation

The following figure shows all ten network codes under development as well as the current status of development (October 2014)[3].

It is worth mentioning that the Network Code entering into force is not yet the end of the process. Some Network Codes (e.g. CACM) will still require many steps from the moment it will enter into force until it is fully implemented. These include the elaboration of new tools or new methodologies. For instance, in the case of CACM, many of the subjects are highly complex and there is relatively little operational experience on which to draw from (for example the flow-based method of capacity calculation). For this reason, CACM requires additional work and a series of methodologies to be jointly developed and approved by regulators after the code enters into force.

## 3.3 Changing the label but not the content: the binding guidelines

For legal reasons, it was recently decided that the regulation on capacity allocation and congestion management, would be labeled "binding guideline" instead of "network codes". However, changing the CACM label to "binding guideline" will not change the content or affect its legal value. Many other codes should maintain their "network code" label but some others may also change in the future. The new label was decided to reflect the particular structure of the CACM text, which left open for later approval a great number of methodologies, because it draws new concepts, and provides Europe with a significant leap forward towards completing the IEM. For the sake of simplicity, we will refer to the term "network code" in this project, to all the

[3] The current status of the NCs development can be found on https://www.entsoe.eu/major-projects/network-code-development/updates-milestones/Pages/default.aspx

common rules for electricity markets, as defined in Regulation (EC) N°714/2009. These include documents labeled either “network codes” or “binding guidelines”.

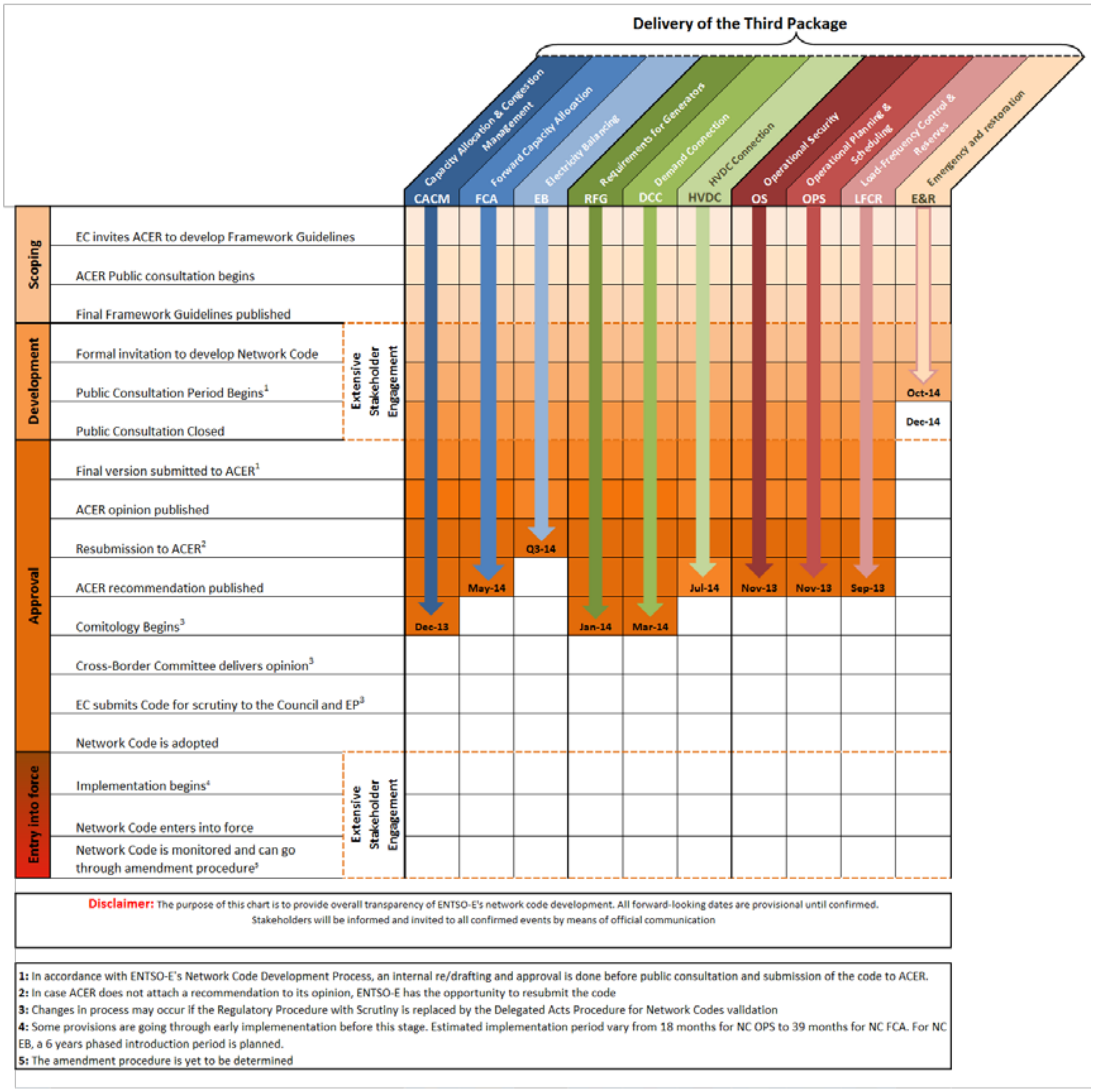


Figure 3-1 – Network Code Status (October 2014). Source: ENTSO-E

## 4 The Market Network Codes

Although the previously introduced NCs’ categories are interrelated, the focus of this report will be on the market-related codes.

In this section we give a general description of the three market network codes: the Capacity Allocation and Congestion Management (CACM), the Forward Capacity Allocation (FCA) and the Balancing Network Code (EB). The algorithm developed for the Price Coupling of Regions project (EUPHEMIA) will be also reviewed. This is a tool that is highly related to the CACM Network Code.

## 4.1 Capacity Allocation and Congestion management

### 4.1.1 Current status of the regulation

Processes for the computation of available capacity and capacity allocation in the short term are described in the Regulation establishing a Network Code on Capacity Allocation and Congestion Management and a guideline on Governance supplementing Regulation (EC) 714/2009, (European Commission, 2014).

**Available Capacity Calculation**

In this section, we are concerned with the computation of available capacity to be allocated in the day-ahead (DA) and intra-day (ID) timeframes. The computation of available capacity is carried out separately for each Capacity Calculation region. Within regions, bidding zones are defined that can be considered a single node for capacity allocation, and therefore used for the computation of the energy dispatch. A single bidding zone may be included in several Capacity Calculation regions; however, each border of one bidding zone must be assigned to only one Capacity Calculation region.

There are two different schemes, or approaches, used for the allocation of scarce transmission capacity in Europe in the DA and ID time frames: (i) the Flow Based Approach, and (ii) the Coordinated Net Transmission Capacity Approach.

- **The Flow Based Approach** takes into account endogenously the existing interdependencies among flows created by transactions among pairs of bidding zones in a Capacity Calculation Region. The Flow Based approach shall be applied on all borders among bidding zones except in those cases where the network exhibits a radial topology (as between Italy and Greece) or within some countries also with a radial topology (like Italy).

- **The Coordinated Net Transmission Capacity** assumes a-priory a certain split of the available capacity in critical transmission assets (those likely to get congested) among transactions taking place between the several pairs of bidding zones that may be defined.

The amount of capacity available on critical assets, or bidding zone borders, must be computed with the latest available information and be updated regularly. Capacity estimates must be available for each market time unit and be computed in an objective way resulting in unique value per time unit. Capacity calculation regions should be merged to the extent that this may increase the efficiency of the dispatch. Loop flows, caused by power transactions in a region, in the remaining ones shall be considered when computing available capacity. In this case, there may also be a need to allocate the capacity of critical assets affected by loop flows among the several capacity calculation regions making use of these assets.

When computing the capacity available both the reliability margin of each element (critical, asset, bidding zone border) and the impact of remedial actions on available capacity need to be taken into account. The reliability margin must be computed based on the probability distribution of deviations between expected power flows in this element at the time of available capacity computation and realized power flows in real time. These shall comprise frequency-control-based deviations and deviations in flows caused by contingencies. Remedial actions are those taken in the event of a contingency or unexpected deviation in flows to ensure that the system remains in a safe operating state.

The TSOs should build each their Individual Grid Models by collecting and assembling the relevant information on generation, demand, and grid topology for the considered scenarios. Then, Individual grid models should be merged into a single Common Grid Model, for all Europe, and each Capacity Calculation Time Frame.

Next, the process of computation of available capacity to be followed for each of the two capacity determination (and dispatch) approaches previously mentioned is discussed.

Within the Flow Based approach, the calculation process is as follows:

1. Operational security limits are used to compute maximum flows on critical elements (MF).
2. Then, from the Common Grid Model, the location of bidding zones[4] in the model, and contingencies, the Power Transfer Distribution factors (PTDFs) of the flow of power in critical elements with respect to injections in bidding zones are computed.
3. Using PTDFs, flows corresponding to cross zonal capacity reserved previously by power transactions in the same Capacity Calculation region are determined (RC).
4. Flows on critical elements already existing in the base-case scenario (OF) are computed. In this baseline scenario, no power exchanges among bidding zones are considered.
5. The available capacity margin on each critical element is computed as the maximum flow in this element less the sum of the reliability margin (RM), the flows corresponding to previously reserved capacity, and the flows in the base scenario.
6. Finally, available margins (AM) are adjusted by taking into account remedial actions possible incrementing them.

The final outcome of this process is the available margin (capacity available to be allocated) in each critical element and the aforementioned PTDFs. According to this process, available margins are computed as in equation (1).

$$AM = MF - RM - RC(PTDFs) - OF \quad (1)$$

Within the Coordinated Net Transmission Capacity Approach, the process of capacity calculation is as follows:

[4] This determines the impact of a change in the net balance of power in each zone on generation and demand in the model

1. First, the available capacity in each element is split among the different bidding zone borders (borders among pairs of bidding zones) in the corresponding Capacity Calculation Region.
2. Then, using the Common Grid model, the location of bidding zones and contingencies, the maximum transfer of power between each pair of bidding zones is computed.
3. After thus, maximum power exchanges are adjusted taking into account remedial actions available and avoiding unfair discrimination among types of transactions.
4. Finally, the available capacity for the exchange of power between each pair of bidding zones (cross-zonal capacities) are computed by deducting the reliability margin and the already allocated cross zonal capacity on this border from the maximum transfer of power between the corresponding pair of zones.

The final outcome of this process is the capacity at the border between each pair of bidding zones available to be allocated.

Capacities computed though either of the two previous processes must be validated by TSOs. One can easily understand that the computation of available capacity, and the outcome of the dispatch itself, depends significantly on the identity and distribution of bidding zones defined. These should be chosen in order to achieve a trade-off among:

A. Their ability to reflect network constraints in the most accurate way possible.
B. Their ability to allow a liquid enough market to develop within each zone where market power is as small as possible.
C. The stability across scenarios and robustness of these zones.

It is clear, in any case, that the bidding zones definition should be updated periodically, as other inputs to the computation of the grid model and available capacity.

But it is also very relevant to have available some process that TSOs in a region can use to solve infeasibilities resulting from the market outcome (the computation of the network constrained economic dispatch over several time frames). Coordinated redispatching mechanisms are used for this. Each TSO must have available a redispatching algorithm to alleviate physical congestion within its area. But the several TSOs must apply their redispatching algorithms in their areas in a coordinated way taking into account the effect that the application of these algorithms may have on the flows on critical elements in other areas.

Cross-zonal capacity calculated shall be firm, for day-ahead time frame, before the gate closure time of the day-ahead market and, for intra-day timeframe, the capacity is firm from the moment it is allocated.

**Capacity Allocation and Congestion Management in the Day-ahead**

Capacity allocation and congestion management in the day-ahead is to be carried out through the price-coupling algorithm being already implemented within some regions in Europe. This scheme must maximize the social surplus resulting from the single day-ahead coupling, and makes use of the marginal pricing principle. Thus, a single clearing price is computed for each bidding zone and market time unit. The solution provided by this must respect cross-zonal capacity and allocation constraints. A more detailed description of the scheme considered within the NC on CACM is provided, together with its assessment, in section 6.2.1.

The day-ahead coupling algorithm is by definition an implicit scheme of cross-zonal transmission capacity allocation. Thus, a market mechanism is applied to determine jointly the use to be made of transmission capacity and energy transactions that are scheduled. This is the general trend followed by proposals made in the IEM context since the first explicit transmission capacity auctions proposed by ETSO was abandoned some 10 years ago.

This mechanism considers setting harmonized maximum and minimum bid prices to be applied all over the European system (for all bidding zones). The price of the transmission capacity at a border connecting two bidding zones will be computed as the difference between the day-ahead clearing prices in the two bidding zones.

Information[5] required to compute the day-ahead dispatch by National Electricity Market Operators, NEMOs, shall be available no later than 12:00 of the day-ahead of delivery. Information on the available cross-zonal transmission capacities provided by each Coordinated Capacity Calculator shall be made available to the corresponding NEMO no later than 11:00 on the day-ahead.

### Capacity Allocation and Congestion Management in the Intra-day

The continuous trading scheme adopted as basic dispatch solution in the intra-day time frame, as it name suggests, aims to continuously allocate available cross-zonal transmission capacity to orders submitted by agents. These orders are matched according to the price of each order and the time when they have been submitted.

Thus, any order submitted by an agent for the purchase or sale of electricity in a certain bidding zone and at a certain time 't' will be allocated the transmission capacity used by the transaction taking place between this agent and another one submitting a bid in this or any other bidding zone. This allocation is made as long as the two bids can be matched according to prices submitted (the price of purchase is at least as high as the price of sale) and there is enough capacity available on the border between the two bidding zones at the time of the match. Obviously, market bids must refer to a specific market time unit when delivery of electricity will take place.

The allocation of capacity carried out according to this scheme shall be compliant with capacity allocation constraints considered and cross-zonal capacity available as computed beforehand. As

[5] This is related to the economic bids made by market agents in their systems

a result of the application of this mechanism, the state of execution of orders submitted by agents and price per trade (matching of orders) performed shall be computed, as well as the net position per bidding zone and market agent for each market time unit. NEMOs and TSOs should publish this information as soon as it is available.

Similarly to what occurs for the day-ahead market, a maximum and minimum bid prices shall be established to be applied in all bidding zones. As a result of the matching of orders, scheduled power exchanges among bidding zones in each market time unit shall be computed. The market gate opening and closure times should be set so as to maximize the opportunities of market agents to balance their positions by trading as close as possible to real time. Simultaneously, it shall take into account the relevant scheduling and balancing processes in relation to operational security. Furthermore, orders matched in the intraday market shall be firm.

In addition to the continuous pan-European intra-day market solution, complementary intra-day regional auctions may take place. Intra-day auctions may take place inside and among bidding zones. In order for these auctions to take place, continuous trading can be stopped for a certain amount of time (no more than 10 minutes). Regional auctions being organized shall not have an adverse impact on the liquidity of the intraday market solution and all the capacity should be allocated through the capacity management module.

**Additional aspects of the allocation of transmission capacity in the short term**

*Coexistence with explicit transmission capacity allocation*

The explicit allocation of interconnection capacity among bidding zones (on bidding zone borders) may co-exist with implicit market coupling schemes in the short term. This shall take place when the competent regulatory authorities request TSOs to have available explicit capacity allocation schemes.

According to the relevant network codes, after some time of operation of explicit capacity allocation, TSOs in a region should find the way to meet the needs of market agents related to transmission capacity rights using some sort of products (non-standard ones) negotiated through existing implicit schemes.

*Ensuring the feasibility of the market outcome*

Achieving a feasible dispatch may require making changes to the outcome of day-ahead and intra-day markets. This is a consequence of the realization of uncertainties related to the functioning of electricity systems and markets. Changes to the outcome of both coupling processes are to be computed through a re-dispatch or countertrade mechanism called by TSOs in a price zone.

*Central market counter-party and firmness of transactions*

Both in the day-ahead and in the intra-day coupling markets there shall be a central counter-party to any market agent whose orders are matched. This shall be defined for clearing and settlement purposes and ensure that the energy balance is kept.

The existence of central counter-parties should allow cross-zonal capacity allocated to be firm. If, due to force majeure reasons, capacity already allocated needs to be curtailed, agents having acquired this capacity shall be compensated according to market price differences between the corresponding two zones or, if prices are not available and an explicit auction took place, according to the price paid by ach agent in the auction.

*Allocation of system operation and development costs related to the existence of the transmission grid*

If no cost-sharing takes place, each TSO would be responsible of affording the expenses associated with changes to be made to the program of generators in his area. However, a methodology for sharing regionally costs of counter-trade, or re-dispatch, should be agreed and proposed. This methodology should be coherent with the allocation of other costs and revenues related to the existence of the transmission grid. A list of the latter follows:

- Allocation of the system congestion income, or net amount resulting from the application of energy prices to transactions negotiated in day-ahead and intra-day markets.
- Inter-TSO payment scheme in place to allocate the cost of the fraction of the transmission grid used by regional power transactions (those involving agents from several bidding zones).

Counter trade belongs to the family of redispatch-kind of congestion management mechanisms. The advantage of the former, within redispatch mechanisms, lies in its simplicity. However, it is only suitable to be applied in systems where congestion divides the network in a set of radially-connected areas. There, the impact of changes in the dispatch in each area on flows on congested links can be easily anticipated. In systems where congestion areas make a meshed grid a full-fledged, network-constrained, redispatch optimization process should be implemented.

Besides this, cost-sharing methodologies applied should comply with the requirements that follow:

- They should facilitate the efficient development and operation of the pan-European system and market.
- They should avoid discrimination among agents and types of transactions in the allocation of capacity. Thus, there should not exist unfair discrimination against explicit capacity allocation, or vice-versa. Lastly, these methodologies should reasonably allow authorities to plan revenues and expenses to be incurred by each area and be compatible across time-frames.

*Allocation of costs related to the management of market and congestion management processes*

The cost of management of market coupling processes shall be borne by the National Electricity Market Operators (NEMO) in the region. There may be an agreement between NEMOs and TSOs to cover these costs. Costs not covered by TSOs can be charged by NEMOs on market participants in the form of fees. Costs incurred by Central Counter Parties shall be recovered through fees as well.

Similarly, TSOs shall born costs related to the calculation of available cross-zonal capacity including the merging of individual network models. The costs borne by TSOs shall be recovered from network charges or other fees related to regulated costs.

Costs related to the management of market processes and capacity calculation (in the intra-day and day-ahead time frames) can be classified into common costs, regional costs and national costs. Common costs shall be shared among all TSOs and NEMOs according to several criteria. According to some proposals still to be approved, one part should be socialized to all countries; five parts should be allocated proportionally to the demand in each country; and two parts should be socialized to all NEMOs.

*Application in Island Systems with Central Dispatch*

The provisions for day-ahead and intraday market coupling shall not be fully applicable to Island system like Ireland until the 31st of December, 2016. This may be reasonable, since it has already been deployed in a large part of Europe. Until then, these systems shall prepare for the full implementation of these market arrangements by the deadline and, meanwhile, apply a transitional capacity allocation scheme that should at least include the explicit allocation of interconnection capacity in the day-ahead time frame and the implicit allocation of capacity in the intraday one; the joint nomination of interconnection capacity and energy in the day-ahead; and the application of use-it-or-lose-it or use-it-or-sell-it rules to capacity allocation.

*Participation of third countries in the intra-day and day-ahead market coupling processes*

Third countries or areas not belonging to the EU could participate in these market arrangements as far as they have implemented market principles of the EU IEM. Some coordination between competent local authorities in these system and EU ones (including ACER) should take place for this.

### 4.1.2 Relevant pending implementation aspects that are not defined by the regulation

This point discusses those relevant aspects of regulation on Capacity Allocation and Congestion Management to be implemented that are not defined within the latest version of the Network Code. The reason for this may be that some of the methodologies require additional work. So they are left to be defined throughout the implementation process after the regulation enters into force.

There are several proposals and methodologies to be developed and approved during the implementation process. Some of these proposals and methodologies are of European wide application while others have a regional scope. Some of them have already been partially or totally implemented during the early implementation phase while others will need to be developed after the CACM Regulation is approved. The proposals and methodologies for development and approval in the CACM are the following. We indicate whether these issues are European or regional in scope within brackets.

- **Definition of the Capacity Calculation Regions** – All TSOs shall jointly develop a proposal regarding the determination of the capacity calculation regions. This is a very relevant decision as market outcome will largely depend on the borders considered for capacity calculation regions. For the time being, and with some notable exceptions like the Nordic region, capacity calculation regions have been made largely coincident with control areas or countries. (European);
- **Methodologies for generation and load data provision to build a common grid model** – All TSOs shall jointly develop a proposal for a single methodology for the delivery of the generation and load data for the establishment of a common grid model. Also, TSOs should propose a common grid model methodology. (European)
- **Other capacity calculation elements** – TSOs must also agree on a methodology to determine reliability margins, as well as common generation shift keys. The latter are the associations created between generators and loads and the capacity calculation regions where they are located. These make, therefore, a map of the location of generators and load in the zonal network model considered for congestion management. (European)
- **Maximum and minimum bid prices for day-ahead and intra-day markets** – All NEMOs shall, in cooperation with TSOs, develop a proposal on harmonized maximum and minimum bid prices to be applied in day-ahead and Intra-day market coupling. (European)
- **Algorithm requirements** – TSOs shall provide NEMOs with a proposal for a set of requirements to enable the development of the price coupling algorithm. This task is already partially implemented as part of Europe is already coupled. More requirements may be added with the implementation of the market coupling process in more countries. (European)
- **Products to be used by NEMOs in the day-ahead and Intraday processes** – This task is also partially done as the day-ahead market coupling is already in place in some countries. The products used in the day-ahead and intraday processes can be revised every two years, (European)
- **Intraday capacity pricing methodology** – The model chosen for the intraday trading is a continuous one. The CACM NC states that TSOs should develop a proposal of a single methodology to price intraday cross-zonal capacity, within the allocation mechanism, that is able to reflect market congestion and is based on actual orders. (European)
- **Day-Ahead firmness deadline** – TSOs shall submit a common proposal for a single day-ahead firmness deadline which shall not be shorter than half an hour before the day-ahead market gate closure time. After this deadline the available transmission capacity given to the market

is considered firm and cannot be changed. For the time being there is no single day-ahead firmness deadline for the whole Europe. (European)

- **Congestion income methodology** – All TSOs shall develop a proposal for a methodology for sharing congestion income. This proposal should respect some pre-defined principles related to efficient market functioning, financial planning, compatibility across timeframes, allowing the share of income deriving from non regulated assets, and also comply with the general principles of Article 16 of Regulation (EC) Nº 714/2009. For the moment the agreements are established bilaterally and no kind of pre-defined harmonization exists. (European)
- **Common capacity calculation methodology** – At regional level it should be established a common capacity calculation methodology. This methodology should improve the existing agreements for capacity calculation and create a common framework. (European)
- **Methodology for coordinated redispatch and countertrading** – This is a methodology to be developed at regional level aiming at having a common procedure to coordinated redispatch and countertrading actions. (regional)
- **Redispatch and countertrading cost sharing methodology** – As in the previous methodology, at regional level, the TSOs must establish a common methodology to share countertrading and redispatching costs. (regional)
- **Fallback procedures** – TSOs must establish and operate a fallback procedure for capacity allocation in relevant borders in case the single day-ahead coupling process is unable to produce results. Typically, the TSOs might perform an explicit allocation through a "shadow auction" which is communicated to the market once the decoupling is announced, (European)
- **Complementary regional auctions** – It is possible for NEMOs and TSOs to propose at regional level the existence of complementary regional auctions as long as it doesn't hinder the well-functioning of the European market. (regional)

## 4.2 The PCR and the EUPHEMIA algorithm[6]

The Price Coupling of Regions (PCR) project is an initiative of seven Power Exchanges (PXs): APX, Belpex, EPEX SPOT, GME, Nord Pool Spot, OMIE and OTE[7]. The joint cooperation between these PXs in the PCR project has aimed at establishing an integrated day-ahead wholesale electricity market, increasing the efficient allocation of interconnection capacities of the involved countries (a major issue in the past).

[6] This high level description of the algorithm is based on Europex (2014).

[7] These PXs cover the electricity markets in Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia, Sweden and the UK.

One of the core elements of the Price Coupling of Regions project has been the development of a single price coupling algorithm (EUPHEMIA, acronym of Pan-European Hybrid Electricity Market Integration Algorithm). EUPHEMIA largely complies with the requirements set in the NC CACM. With the single price coupling algorithm, the PCR effectively joins and integrates different energy markets into one cross-border market.

The development of EUPHEMIA started in July 2011 using as a basis one of the participating PX existing algorithms (COSMOS, which was in use in CWE since November 2010).

In the new PCR context, market participants submit orders to their respective power exchange. The unified algorithm then determines the quantities committed and the prices in each bidding area, but also the cross-border flows (this way, the cross border capacity made available to EUPHEMIA is assigned implicitly). In EUPHEMIA, a *bidding area* is the smallest geographical area representing a given market where orders can be submitted.

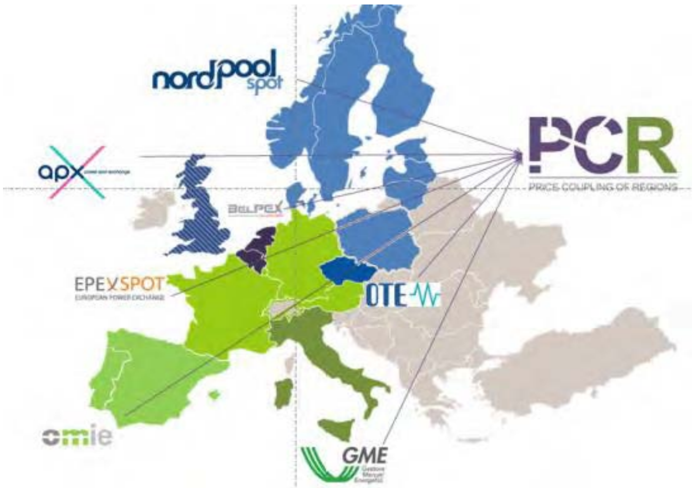


Figure 4-1 The PXs involved in the PCR project

### Description of the algorithm

At a very high level, the objective of EUPHEMIA is to maximize the social welfare. This entails the maximization of the summation of: (i) the consumer surplus, (ii) the producer surplus and (iii) the resulting congestion rent across the different regions. This maximization is subject to several constraints, some associated to agents bids and some others associated to the representation of the European network.

### Representation of the network

EUPHEMIA computes a market clearing price for every *bidding area* per period and a corresponding *net position* (calculated as the difference between the matched supply and the matched demand quantities belonging to that *bidding area*).

The exchange of energy between bidding areas can be determined according to three different alternatives:

- **An Available Transfer Capacity (ATC) model** - In an ATC model, the *bidding areas* are linked by interconnectors (lines) representing a given topology. The energy from one *bidding area* to another can only flow through these lines and is limited by the available transfer capacity (ATC). The flow on a line can be subject to losses, to a tariff[8] and to ramping constraints. The available transfer capacity of a line can be different per period and direction of the transfer.

- **A flow based model** - Modelling network constraints using a flow based model allows a more precise representation of the physical flows. The FB constraints are given by two components: (i) Remaining Available Margin (RAM): the number of MW available for exchanges, and (ii) the Power Transfer Distribution Factor (PTDF): a ratio indicating how much MWh are used by the net positions (NP) resulting from the exchanges.
    - o The constraints representing the network that are considered in the flow based model are of the form:

$$\sum_i NP_i * PTDF_{ij} = RAM_i \qquad (2)$$

  A so-called non-intuitive flow situation arises when the flow does not go from the lower price bidding area to the higher price bidding area. The reason for this to happen is that some non-intuitive exchanges can free up capacity in some other constrained interconnectors, allowing even larger exchanges between other markets (and in the end maximizing the social benefit of the whole system). EUPHEMIA integrates a mechanism to suppress these non-intuitive exchanges (by altering the value of the PTDFs).

- A hybrid model (hybrid of the previous two)

**Market Orders**

In the past, several algorithms were used locally by the involved PXs. Each of them (e.g. COSMOS, SESAM, SIOM and UPPO) was focused on the features of the corresponding PX and the necessities expressed by local market agents. This led to the implementation of different types of market orders (formats of market bids). When designing a common algorithm, one major concern was that of covering all the agents' requirements at the same time. This has led in practice to an algorithm that is capable of handling a large variety of market order types (most of those originally available in each system). These market orders are:

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[8] In an ATC network model, the DC cables might be operated by merchant companies, who levy the cost incurred for each passing MWh in the cable. In the algorithm, these costs can be represented as flow tariffs.

- **Aggregated Hourly Orders:** hourly price-quantity curves, either represented by linear piece-wise, by step-wise segments or even by a combination of piece-wise and step-wise segments.
- **Complex Orders:** A complex order is a set of simple supply stepwise hourly orders (which are referred to as hourly sub-orders) belonging to a single market participant, spreading out along different periods and are subject to a complex condition that affects the set of hourly sub-orders as a whole.
  - **Minimum Income Condition (MIC) orders:** the Minimum Income economical constraint means that the amount of money collected by the order in all periods must cover its production costs, which is defined by a fix term (representing the startup cost of a power plant) and a variable term multiplied by the total assigned energy (representing the operation cost per MWh of a power plant). In case a MIC order is deactivated, each of the hourly sub-orders of the MIC is fully rejected
  - **Load Gradient orders** - the Load Gradient constraint means that the amount of energy that is matched by the hourly sub-orders belonging to a Load Gradient order in one period is limited by the amount of energy that was matched by the hourly sub-orders in the previous period. There is a maximum increment / decrement allowed.
- Block Orders –
  - **Regular block order:** where agents are allowed to submit on one hand a certain interval of consecutive hours where they are willing to produce, and on the other hand the minimum average price they require to be committed (i.e. it is a minimum income condition over one particular dispatch).
  - **Profiled block order:** it is a more general case of block order, where the periods and the volume offered in each period can be defined by the bidder. It is also possible to include a minimum acceptance ratio, to allow for partial commitment of the order in case the price of the bid is exactly met by market conditions.
  - **Linked Block Orders** - Block orders can be linked together, i.e. the acceptance of individual block orders can be made dependent on the acceptance of other block orders. The block which acceptance depends on the acceptance of another block is called "child block", whereas the block which conditions the acceptance of other blocks is called "parent block".
  - **Exclusive Groups of Block Orders** - An Exclusive group is a set of block orders for which the sum of the accepted ratios cannot exceed 1. In the particular case of blocks that have a minimum acceptance ratio of 1 it means that at most one of the blocks of the exclusive group can be accepted.
  - **Flexible Hourly Orders** - A flexible "hourly" order is a block order with a fixed price limit, a fixed volume, minimum acceptance ratio of 1, with duration of 1 hour. The hour is not defined by the participant but will be determined by the algorithm (hence the name "flexible").
- Others: merit Orders and PUN Orders

## 4.3 Forward Capacity Allocation (FCA)

### 4.3.1 Current status of the regulation

The description of processes to be followed for FCA is based on the description in (ENTSO-E, 2014).

The Forward Capacity Allocation Network Code prescribes common rules for the establishment of a common methodology and process for determining the Cross Zonal Capacity and its subsequent allocation in the long-term

Forward capacity allocation shall be implemented on all those bidding zone borders where competent National Regulatory Authorities (NRAs) determine that market agents are in need of such instruments. Even when NRAs are competent over these, there should probably be a benchmark/indicator to be able to determine whether or not there is such a risk. This would be needed in order not to have haphazard decisions by NRAs. Tools like these help to manage the risk associated with the volatility in the price to be paid to access the grid to inject power in a certain bidding zone and retrieve it in another one.

In particular, the FCA establishes common rules and guidelines around:

- Long-term transmission capacity determination
- The single allocation platform for cross-border capacity rights
- The long-term transmission capacity products and the associated firmness
- Homogenize nomination rules for physical transmission rights
- Others: financial requirements and fallback procedures, publication of information and secondary trading

**Long-term transmission capacity determination**

Forward capacity allocation, which must be preceded by the computation of available long term transmission capacity, must take place in a coordinated manner within a region.

The computation of long term transmission capacity available shall be carried out with a certain degree of regional coordination. Some statistical analysis of available capacities in the future may be carried out to take into account existing uncertainty about future system conditions.

There are two main approaches to the computation of available capacity and the allocation of this capacity in the long term, which are analogous to those available in the short term: 1) the Coordinated Net Transmission Capacity based and 2) the Flow based:

- **Coordinated Net Transmission Capacity based approach:** involves the separate allocation of capacity on the border between each two bidding zones. Thus, a predefined amount of transmission capacity is made available to transactions taking place between each pair of bidding zones. First, the available transmission capacity on each critical element needs to be split in slices to be separately allocated to transactions between each two zones. This may be a suitable approach to be applied in regions whose network has a radial topology and, therefore, there are limited interactions among power flows on borders created by transactions between two or more different pairs of zones.

- Flow based approach: it involves the joint, centralized, allocation of transmission capacity on all critical grid elements to transactions taking place between all pairs of zones. Thus instead of defining the transmission capacity on the border between each pair of zones, the capacity of each critical element of the transmission grids is defined and allocated to transactions between any pair of zones. This is superior to the Coordinated Net Transmission Capacity based approach from an economic efficiency point of view, since it allows the use of a larger fraction of transmission capacity in each critical element, due to the fact that interdependencies among flows on several grid elements caused by transactions between the several pairs of zones are accounted for. However, it required a higher level of coordination and centralization in the capacity allocation process. Its use is justified in meshed grids.

The capacity calculation methodology for Forward Capacity Allocation shall ensure compatibility and consistency with the capacity calculation methodology of the day ahead and intra-day timeframes pursuant to the Network Code on Capacity Allocation and Congestion Management. The methodology for Forward Capacity Determination shall meet the following objectives: (i) be coherent with Forward Capacity Allocation defined in the NC and (ii) properly manage the uncertainty in the Long Term capacity calculation timeframes in a coordinated and consistent manner in the calculation of Long Term Cross Zonal Capacity.

The details of the final methodology are to be defined after the NC enters into force.

**The single allocation platform for cross-border capacity rights**

As described in the FCA network code, "the Transmission System Operators shall establish and operate a Single Allocation Platform at the pan-European level. The Single Allocation Platform is a single point of contact for Market Participants participating in Explicit Auctions to acquire Long Term Transmission Rights. This central platform shall be developed by all Transmission System Operators to ease the operation of allocation of Long Term Transmission Rights for Market Participants."

*Time frames*

The forward allocation of transmission capacity (long term capacity) in this platform may take place in several time frames. It shall at least take place in the annual and monthly time frame, i.e. a year and a month ahead of delivery. Thus, a split of available transmission capacity needs to take place among the different time frames considered in the allocation process. This should allow the efficient arbitrage of prices of transmission capacity in each time frame.

*Products*

The allocation of transmission capacity shall take place in the form of transmission rights of different kinds. Transmission rights shall first be issued in the context of a long term auction. Then, rights acquired by market agents may be traded subsequently in other auctions or bilaterally among agents. However, authorities must be always aware of the property of transmission rights over capacity in each border or network element.

The price of long term transmission rights issued shall be determined according to the marginal pricing principle applied to the corresponding Forward Capacity Allocation (auction).

A list of the types of transmission rights that can be issued and traded follows:

A. **Physical transmission rights**: involve the right to physically use the transmission capacity they refer to. They need to be nominated in order for their owner to use this capacity. Therefore, they involve the right to physically use the corresponding capacity; and the right, and obligation, to earn the congestion rents for these rights, or price difference between the two points considered in the right times the capacity of rights owned. If not nominated, the capacity they refer to shall be auctioned for its use in the short term (in the day-ahead, together with energy), and the owner of long term rights shall be paid according to the value of this capacity in the auction. Thus, a clause of the type Use-It-or-Sell-It shall apply to the capacity there rights refer to.
B. **Financial transmission rights in the form of options.** They provide the right to earn the price difference resulting from the implicit auctioning of the corresponding capacity in the day-ahead. However, if prices differences have the opposite sign to that defined in financial rights in the form of options, right owners will not need to face any payment.
C. **Financial transmission rights in the form of obligations.** They provide the right, and obligation, to earn, or pay, the corresponding congestion rents.

According to marginal pricing theory, the determination of the congestion income for long term transmission capacity rights shall be based on the difference in prices within the day-ahead dispatch between both bidding zones each transmission right refers to. If implicit auctions are not implemented and explicit auctioning takes place in the short term, the revenues of right holders shall be determined as those from the direct sale in auctions of the capacity these rights refer to.

The harmonised Allocation Rules for Physical Transmission Rights and the harmonised Allocation Rules for Financial Transmission Rights shall be consistent with each other, unless the characteristics of the product require them to differ

According to the network codes, it shall not be possible to simultaneously issue and allocate physical and financial transmission rights on the same border in a single auction.

*Firmness of the commitment*

If transmission rights already issued and considered as firm are curtailed, this shall be compensated according to the procedure outlined in the CACM Network Code. If these rights are curtailed before the firmness deadline, owners will have the right to earn compensation, but the overall compensation received by owners shall not exceed the income derived from the allocation of Long Term Transmission rights.

The firmness of the commitment and the penalties associated has been (and still is) one of the most controversial points of the Code.

*The TSO as a counterpart of the product*

Each TSO shall issue Long Term Transmission Rights unless National Regulatory Authorities competent on the relevant bidding zone border(s) have issued a decision that the TSO shall not. In this case the decision shall be based on an assessment, which shall include at least: (i) a consultation with Market Participants about their needs for cross zonal risk hedging opportunities on the concerned bidding Zone Border(s); and (ii) an evaluation performed in a coordinated manner on a regional level on whether Forward financial electricity markets are well developed and have shown their efficiency or whether other cross zonal hedging opportunities are needed. Such evaluation shall be based on transparent criteria.

**Homogenize nomination rules for physical transmission rights**

In the FCA NC it is established that Nomination Rules should be homogenized and that they shall contain at least the following information:

a) Entitlement for Physical Transmission Rights holder to nominate;
b) Minimum technical requirements to nominate;
c) Description of the Nomination process;
d) Nomination timings; and format of Nomination and communication

### 4.3.2 Relevant pending implementation aspects and those not defined by the regulation

This section discusses those relevant aspects of regulation on Forward Capacity Allocation to be implemented that are not defined within the latest version available of the Network Code[9]. The reason for this may be that an agreement has not been reached in this regard among relevant

[9] This is described in (ENTSO-e 2014f)

stakeholders, or that these aspects are left to be defined throughout the implementation process to take place in each region once a definite version of the Network Code has been approved.

Most of the aspects that need more refinement in their definition are already identified in the body of the network code, among others:

- The definition of the common and coordinated **capacity calculation methodology** for Forward Capacity Allocation. This is to be carried out by all Transmission System Operators of each Capacity Calculation Region no later than 12 months after the entry into force of the NC.
    - Includes the capacity calculation timeframes to be taken into account in the Common Grid Mode
- All Transmission System Operators of each Capacity Calculation Region shall develop a proposal for the Long Term Transmission Rights to be issued on each bidding zone border(s). The proposal shall include timescales for implementation and at least the description of the following characteristics defined in the Allocation Rules: (i) type of Long Term Transmission Rights (Physical Transmission Rights, Financial Transmission Rights Option, Financial Transmission Rights Obligation); (ii) Forward Capacity Allocation timeframe (e.g. yearly, monthly); (iii) form of product (e.g. base, peak, off-peak); (iv) the bidding zone border(s) covered; (v) participating Transmission System Operators; and (vi) involved National Regulatory Authority(ies)
- Determination of long-term transmission rights remuneration, firmness and caps: All Transmission System Operators on a bidding zone Border shall develop a proposal for the calculation of Long Term Transmission Rights remuneration respecting the principles set in the NC. The proposal for the calculation of the Long Term Transmission Rights remuneration shall take transmission losses on interconnections between bidding zones into account, where these losses have been included in the Day Ahead capacity Allocation process.
- Details on how to devise and implement the single allocation platform
- How to articulate secondary trading of transmission rights
- The details of the nomination rules

## 4.4 Electricity Balancing (EB)

### 4.4.1 Current status of the regulation

Electricity Balancing refers to the role of TSOs in ensuring the balance between generation and demand in real time, maintaining the system frequency within a predefined range. In order to guarantee this balance at all times TSOs procure balancing services. Electricity balancing generally involves three main pillars: balance responsibility, balancing services' provision and imbalance settlement, (Chaves-Ávila et al., 2013; van der Veen and Hakvoort, 2009). Balance responsibility defines the obligation of market participants to send production/consumption schedules to the TSO and their financial responsibility for deviations with respect to their market schedules. Market participants can either undertake directly this responsibility, they play then the role of Balance Responsible Parties (BRPs), or they can subcontract a third party ensuring the role of BRP for them. Balancing services' provision defines how balancing services are procured, which agents are allowed to participate in service provision, and how these agents are remunerated. Units that are technically qualified to participate in balancing services provision according to the TSOs' requirements are called Balancing Service Providers (BSPs). It is worth mentioning that all BSPs are BRPs (although not all BRPs are qualified as BSPs). Finally, the imbalance settlement defines how imbalances are measured and imbalance prices computed

The Framework Guidelines on Electricity Balancing (FG EB) sets the basis for NC Electricity Balancing (NC EB) in Europe by defining the principles for the development of the Network Code on Electricity Balancing (NC EB) (ACER, 2012b). The NC EB (ENTSO-E, 2014b) shall be binding and directly applicable in all Member States after its entry into force. The TM EB aims at providing a solid common framework for national balancing markets in order to achieve a single European EB market. Balancing market integration, and ultimately having a single EB market, requires the standardization and harmonization of key elements such as balancing products, balancing energy pricing and imbalance pricing. The core element of the NC EB is the models for cross-border exchanges of balancing energy, which should first emerge in different geographical areas (Coordinated Balancing Areas or CoBAs). CoBAs will then be gradually integrated into one European platform where all TSOs can have access to different types of balancing energy while taking into account the transmission capacities available between different areas.

In the following, balancing services are defined according to the Network Code on Load-Frequency Control and Reserves (NC LFCR) (ENTSO-E, 2013b). After that, the main common principle and rules for electricity balancing established in the NC EB are presented. These principles and rules refer to: (i) the models for the integration of national balancing markets, (ii) procurement of balancing services, (iii) cross-zonal capacity for balancing services, and (iv) the imbalance settlement.

**Definition of balancing services according to the Network Code on Load-Frequency Control and Reserves (NC LFCR)**

The NC EB is highly related with the NC LFCR: while the NC LFCR defines the technical characteristics of the processes and the corresponding reserves used by TSOs to perform balancing actions, the NC EB defines the common principles for balancing products and balancing market designs Figure 4-2).

In order to maintain the balance between generation and demand in real time, TSOs perform the following processes (as defined in the NC LFCR):

- **The Frequency Containment Process (FCP)**, which stabilizes the system frequency at a stationary value after a disturbance (large generation or load outages) by a joint action of Frequency Containment Reserves (FCR) within the whole Synchronous Area. FCR is automatically activated.

- **The Frequency Restoration Process (FRP)**, which brings back the system frequency to its nominal value and replaces the activated FCR through the activation of Frequency Restoration Reserves (FRR). In this respect there are two types of FRR: FRR with automatic activation and FRR with manual activation.
- **The Reserve Replacement Process (RRP)**, which replaces the activated FRR through the activation of Replacement Reserves (RR). RR is manually activated

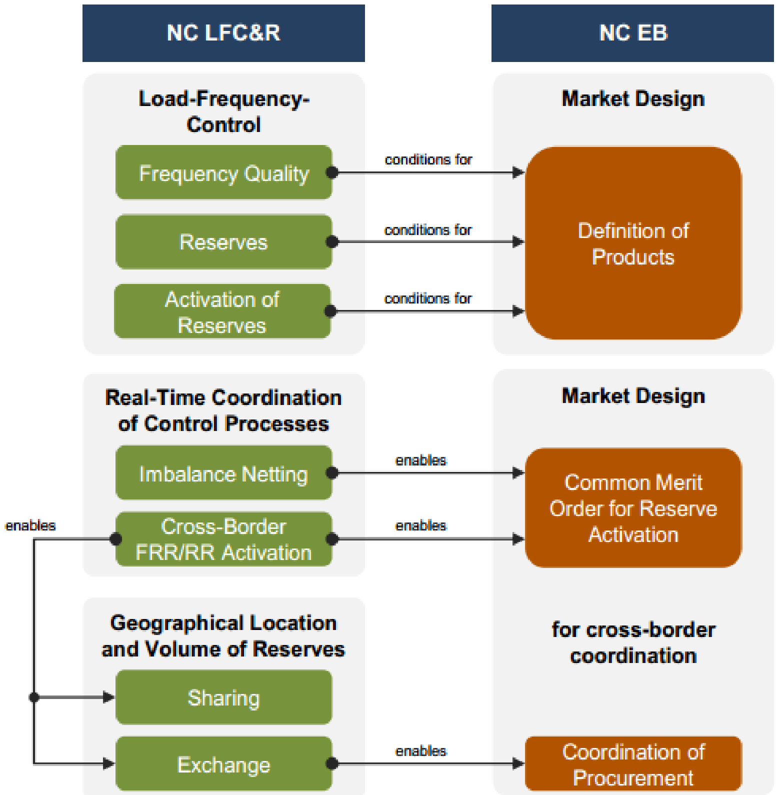


Figure 4-2: Relation between the NC EB and the NC LFR

The Load-Frequency Control processes in Europe are governed by a global framework, which consists of the following levels:

- **European level:** Definition of the common control processes FCP, FRP and RRP as well as the according FCR, FRR, and RR rules for cross-border cooperation.
- **Synchronous Area level**: Establishment of the control structure, definition of a common frequency quality target and application of the FCP. Examples of synchronous areas: Nordic, Ireland, Great Britain and Continental European.
- **LFC Block level**: Definition of a frequency restoration target and application of the FRR and RR Dimensioning Rules. Example of LFC block: Germany

- **LFC Area level**: Application of the FRP and RRP. Example of LFC areas: 50HzT, Amprion, TenneT Germany and TransnetBW (Germany TSOs' control areas).

The reserves used by TSOs to guarantee the balance between generation and demand in real time – FCR, FRR and RR – are commonly referred as balancing services. In general, TSOs define one or more products for each type of reserve and procure these products through markets or other mechanisms. Balancing services' products can be divided into two main categories:

- balancing capacity, i.e. power capacity reserved in advance which can be activated in real time to solve an imbalance;
- and balancing energy, which refers to the actual variation of generation and/or consumption (activated energy) in real time to reestablish the balance between generation and demand.

Each of these categories can be subdivided into upward reserve, i.e. balancing capacity or energy procured to compensate lack of generation/excess of consumption, and downward reserve, i.e. balancing capacity or energy procured to compensate generation surpluses/demand reductions.

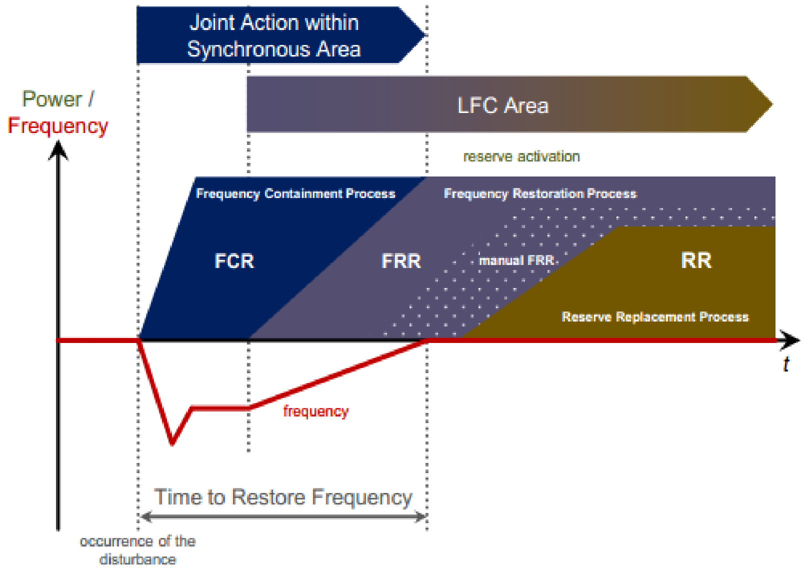


Figure 4-3. Dynamic hierarchy of Load-Frequency Control processes (Source: NC LFCR)

Currently, there is a lack of harmonization among EU countries not only related to the mechanisms applied for the procurement of balancing services but also related to the definition of balancing services' products themselves. Therefore, one of the main elements of the TM EB is the standardization and harmonization of balancing products and markets.

**Models for the integration of national balancing markets**

The final goal of the TM EB is the creation of a single European market for the exchange of balancing energy products from FRR (with automatic and manual activation) and RR (see Figure

4-4). Exchange of balancing energy refers to the process in which a TSO activate a balancing energy bid from a BSP connected to another TSO's responsibility area. The exchange of balancing energy products shall be done through a Common Merit Order List, to where all participating TSOs send all their balancing energy bids, which are activated according to the bids' prices order (i.e. from the cheapest to the most expensive ones).

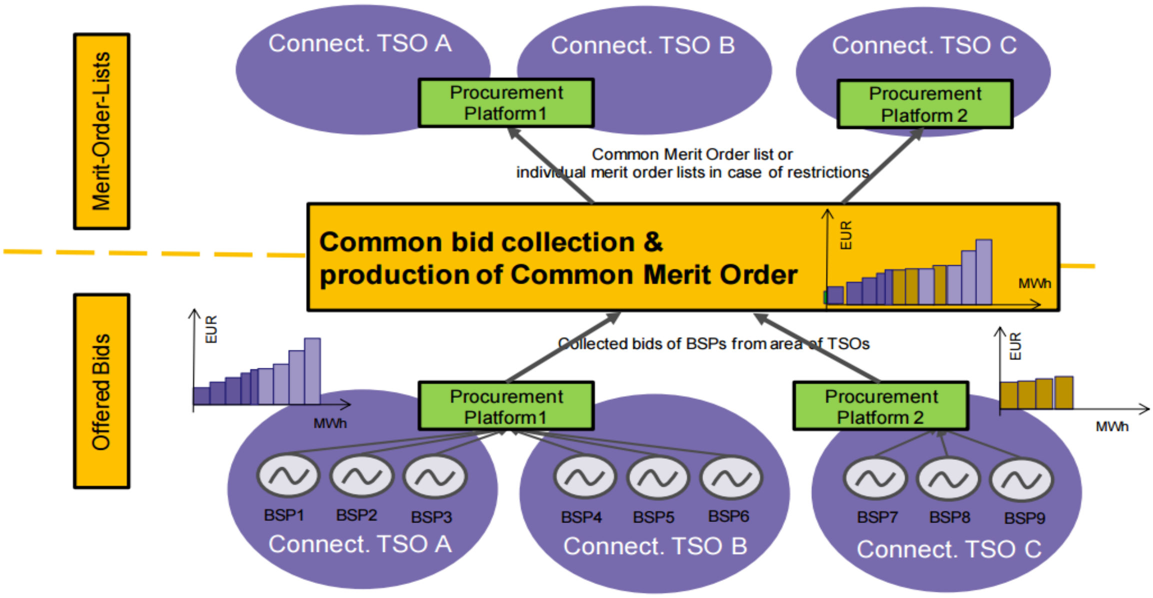


Figure 4-4: Procurement of Balancing Energy with Common Merit Order List (Source: Supporting Document for the Network Code on Electricity Balancing).

It is important to emphasize that sharing and/or exchange of balancing capacity is allowed, but not mandatory in a first stage. As a start, only one balancing energy product or netting of unbalances is mandatory. However, the exchange of balancing capacity, and therefore that of balancing energy, is foreseen by TM when full implementation of it takes place. According to the NC LFCR, sharing of balancing capacity is a mechanism through which more than one TSO take the same balancing capacity from FCR, FRR or RR into account to fulfill their respective reserve requirements. Exchange of balancing capacity refers to the process of procuring Balancing Capacity by a TSO in a different responsibility area.

Currently there are two models related to cross-border procurement of balancing capacity and balancing energy products: the TSO-TSO model and the TSO-BSP model. In the TSO-TSO model all interactions with a BSP connected to another TSO's responsibility area are carried on through the connecting TSO (i.e. TSO responsible for the control area to which the BSP is connected). In the TSO-BSP model one or more BSPs have a contractual relationship with the requesting TSO/TSOs (the requesting TSO is the one who procures balancing services' products from BSPs connected outside its responsibility area). The TM EB establishes that the future EU-wide EB market (i.e. activation of balancing energy) should be based on the TSO-TSO model.

Since harmonizing and coordinating all EU national EB markets is neither an easy nor a short-term task, the harmonization process will start with the creation of coordinated balancing areas (CoBAs). The NC EB requires that each TSO form at least one CoBA with two or more TSOs operating in different Member States and that each TSO within a CoBA exchange at least one balancing energy product or operate the imbalance netting process. The imbalance netting process is a process by which two or more TSOs within one or more synchronous areas avoid the simultaneous activation of FRR in opposite directions. Table 4.1 presents the time schedule currently under discussion (after the entry into force of the NC EB) for the different steps of the TM EB for the achievement of an EU-wide EB markets.

Table 4.1. Time schedule for the implantation of integrated EB markets

| Process | Integration level | Step | Time schedule |
|---|---|---|---|
| Imbalance netting | Regional (one or more CoBAs) | Joint proposal for implementation | 6 months |
| | | Imbalance netting process | 2 years |
| | EU (one CoBA: all TSOs) | Joint proposal for implementation | 4 years |
| RR balancing energy | Regional (one or more CoBAs) | Joint proposal for implementation of common merit order list | 6 months |
| | | Common merit order list implementation (unshared bids allowed) | 2.5 years |
| | EU (one CoBA: all TSOs) | Joint proposal for implementation of common merit order list for all bids | 5 years |
| FRR with manual activation balancing energy | Regional (one or more CoBAs) | Joint proposal for implementation of common merit order list | 2 years |
| | | Common merit order list implementation (unshared bids allowed) | 4 years |
| | EU (one CoBA: all TSOs) | Joint proposal for implementation of common merit order list for all bids | 5 years |
| FRR with automatic activation balancing energy | Regional (one or more CoBAs) | Joint proposal for implementation of common merit order list | 3 years |
| | | Common merit order list (unshared bids allowed) | 4 years |
| | EU (one CoBA: all TSOs) | Joint proposal for implementation of common merit order list for all bids | 5 years |

### Procurement of balancing services

One of the first steps to integrate balancing markets is to harmonize and standardize balancing products. The NC EB requires that, within two years after the entry into force of the code, TSOs develop a list of proposals for standard products covering balancing capacity and balancing energy for FRR and RR, according to a set of requirements. The NC EB also allows for the use of specific products (i.e. products that differ from harmonized standard products jointly defined by TSOs for the exchange of balancing services), as long as:

- It is demonstrated that standard products are not sufficient to meet the balancing needs of a control area or that some balancing resources cannot participate in the balancing market through standard products;
- It is demonstrated that specific products do not create significant inefficiencies and distortions in national markets or in the CoBA.

According to the NC EB, the characteristics that must be used to define standard products include:

a) Preparation period (2): period of time required before the start of the delivery of the first MW;
b) Ramping period (3): period of time comprised between the start of the delivery and the achievement of the operating point requested by the TSO;
c) Full activation time: sum of preparation and ramping periods;
d) Minimum and maximum quantity (4): minimum and/or maximum quantity of single bids expressed in MW;
e) Minimum and maximum duration of delivery period (5): the time during which the BSP delivers the full requested power to the system;
f) Deactivation period (6): period of time comprised between the start of deactivation and the time when the unit reaches its scheduled operating point;
g) Validity period: the period defined by a beginning time (hh:mm) and an ending time (hh:mm) when the bid could be activated. The validity period is, at least, equal to the full delivery period;
h) Divisibility: the minimum divisible unit of balancing energy expressed in MW for volume divisibility and expressed in seconds for delivery period divisibility;
i) Mode of activation: manual or automatic.
j) Price of the bid: price of balancing energy expressed in €/MWh.

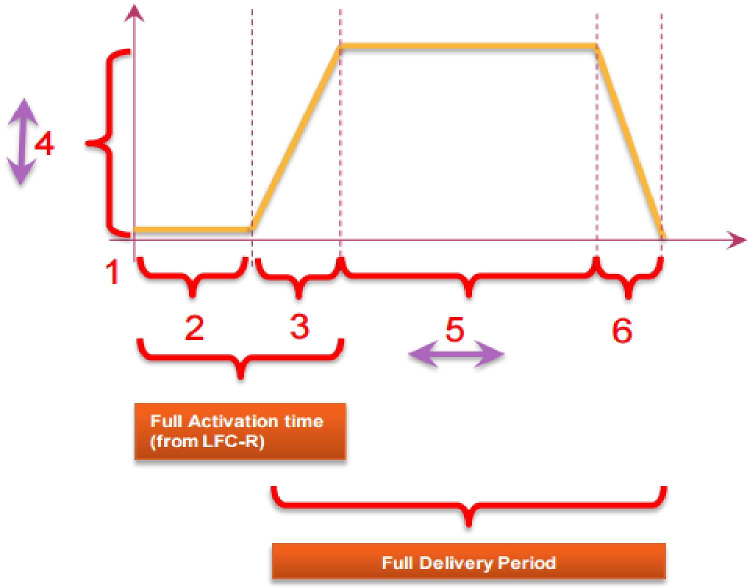


Figure 4-5: Standard Products for Balancing Capacity and Standard Products for Balancing Energy (Source: Supporting Document for the Network Code on Electricity Balancing)

According to the NC EB, the procurement of balancing energy should be done through the creation of common merit order lists for each standard product (i.e. different common merit order lists should be created at least for FRR and RR and for upward and downward balancing energy). The pricing mechanism for at least each standard product should be based on marginal pricing (i.e. paid-as-cleared, whereby all providers obtain the same market-clearing price), unless detailed analyses demonstrates that a different pricing method is more efficient for EU-wide implementation.

Regarding to gate-closure times for balancing energy bids, the NC EB establishes that:

- It should be after the intraday cross-zonal gate closure time for manually activated balancing energy bids and should avoid cross-zonal intraday market and balancing market taking place at the same time;
- TSOs within a CoBA have the right to propose a gate closure time for automatically activated balancing energy bids, which must be as short as possible and with a lead time not longer than 12 hours before real time. In the long-term, the gate closure time for automatically activated balancing energy bids should be after the intraday cross-zonal gate closure time.

### Cross-zonal capacity for balancing services

One of the most relevant elements required to the achievement of cross-border balancing markets is the availability of cross-border transmission capacity. Since the exchange of balancing energy (or the application of the imbalance netting process) can only be done if cross zonal capacity is available. As cross-border capacity is limited, it should be used for the purpose where it yields the largest benefit, which is achieved through market-based allocation up to the day-ahead and intraday timeframes. After the gate closure of the last cross-border intraday market timeframe, cross-border transmission capacity may be available for its use for balancing purposes.

According to the NC EB, the exchange of balancing energy or the application of imbalance netting is only possible if (i) cross-zonal capacity is available after the cross-zonal intraday gate-closure; (ii) cross-zonal capacity is reserved for balancing purposes; or (iii) cross-zonal capacity previously reserved is released for balancing purposes. The NC EB establishes the right to each TSO to reserve cross-zonal transmission capacity for the exchange or sharing of balancing capacity whenever it increases social welfare. Three alternatives through which transmission capacity can be reserved for balancing purposes are foreseen by the NC EB:

1) ***The co-optimization process***: in this process, TSOs would participate in an ordinary transmission capacity auction simultaneously with the procurement of balancing capacity. The bids of the TSOs in the transmission capacity auction would be based on the balancing capacity bids available in each side of the transmission line.
2) ***The market-based reservation process***: if no transmission capacity auction is available for the relevant timeframe for the exchange or sharing of balancing capacity, TSOs can perform the market-based reservation process. The market value of cross-zonal transmission capacity is determined by price differences for different kinds of products (e.g. energy, balancing capacity) on each side of the relevant borders. In the market-based process, the actual market value for the exchange or sharing of balancing capacity is compared with a forecasted market value for the exchange of energy.
3) ***Reservation based on an economic efficiency analysis***: if it is not possible to calculate actual market values neither for the exchange or sharing of balancing capacity nor for energy exchange, an economic efficiency analysis can be performed. In this process, TSOs have to forecast the market values for the exchange of energy and for the exchange or sharing of balancing capacity.

### The imbalance settlement

Regarding the imbalance settlement, the NC EB requires that all withdrawals and injections are covered by a BRP with no exemptions and that each BRP is financially responsible for its imbalances. The NC EB allows for the application of either a single pricing or a dual pricing mechanism. The code establishes that an imbalance price must be calculated for each direction (i.e. for positive and negative imbalances), and the imbalance price for imbalances aggravating system imbalance should at least be related to the average price of balancing energy activated within the area.

According to these rules, the options for imbalance prices applied under a single and a dual imbalance price system are presented in Table 4.2, where $MP_{dw}$ and $MP_{up}$ correspond to the marginal prices of activated downward and upward balancing energy, respectively; $AP_{dw}$ and $AP_{up}$ correspond to the average prices of all activated upward and downward balancing energies, respectively; and $MP_{DA}$ refers to the day-ahead (or intraday) market price. Positive signs refer to the situation when the TSO pays the imbalance price to the BRP and negative signs refer to the case when the BRP pays the imbalance price to the TSO. It is worth mentioning that when balancing energy has a negative price, the direction of the imbalance price payment changes (e.g. when downward balancing energy has a negative price, BRPs with a positive imbalance pay the imbalance price to the TSO while BRPs with a negative sign receive the imbalance price from the TSO).

Table 4.2: Imbalance prices under single and dual-price systems

| | | | **System imbalance** | |
|---|---|---|---|---|
| | | | Positive (long) | Negative (short) |
| ***Single-price system*** | **BRP imbalance** | Positive (long) | $+AP_{dw}/MP_{dw}$ | $+AP_{up}/MP_{up}$ |
| | | Negative (short) | $-AP_{dw}/MP_{dw}$ | $-AP_{up}/MP_{up}$ |
| ***Dual-price system*** | **BRP imbalance** | Positive (long) | $+AP_{dw}/MP_{dw}$ | $+MP_{DA}$ |
| | | Negative (short) | $-MP_{DA}$ | $-AP_{up}/MP_{up}$ |

### 4.4.2 Relevant pending implementation aspects and those not defined within regulation

National balancing markets were developed based mainly on the needs of single TSOs to balance its control area and their designs still vary significantly across EU countries. According to ACER, the complexity of integrating balancing markets is related to the relative limited experience with previous implementation projects (compared to other timeframes) and, consequently, to the lack of useful information on best practices. Added to that, there is the fact that balancing markets have a direct impact on security of supply, increasing the complexity of harmonizing and integrating those markets.

Hence, the NC EB has to create a new standard that will significantly deviate from existing practices in most Member States. Due to the limited clarity on the final TM EB, it is inevitable that many important elements needed for the creation of a European balancing market will have to be developed subsequently, after some more experience is gained with the implementation of pilot projects. Regarding the first version of the NC EB (submitted by ENTSO-E in December 2013), ACER identified the following deviations from the proposed regulation established by the FG EB, which also applies to the current version of the NC EB (ACER, 2014b):

- The NC is not ambitious enough in establishing rules for the harmonization and standardization of the core elements needed to achieve an integrated balancing market. These elements include:
    - Provision of incentives to BRPs to balance themselves or to help reducing the system balancing: The NC EB does not ensure the publication of all information required to ensure an economically-efficient functioning of balancing markets, such as information regarding volumes and prices of all balancing energy bids and all activated balancing energy bids in the previous imbalance settlement periods. In order to incentivize BRPs to reduce the system imbalance and/or to restore its balance, this information should be published shortly after real time. Furthermore,

together with the publication of this information, the application of single imbalance pricing provides higher incentives to BRPs to help the system balancing. Furthermore, the NC EB does not respect the maximum lead-time for the balancing gate closure as established in the FG EB (i.e. one hour before real-time).

  - Fostering competition (in particular across borders) among BSPs: For instance, the NC EB gives much freedom to TSOs when defining balancing products. The NC EB should be more prescriptive when defining standard and specific products in order to avoid market fragmentation and a high number of common merit lists, which reduce market liquidity and undermine competition.
  - Optimizing balancing actions performed by TSOs: the NC EB gives much freedom to TSOs to define their unshared bids. The FG EB allows for unshared bids as long as the concerns about the security of supply are justified and demonstrated. The only limitation the NC EB imposes on the amount of unshared bids is that it should not be higher than the amount of procured balancing capacity for the corresponding FRR and RR.
- The NC should include well-detailed common principles for the establishment of the methodologies of the terms and conditions related for BSPs and BRPs, for instance, the definition of common technical requirements to become a BSP and prequalification procedures are not explicitly included. Also here much freedom is given to TSOs.
- The NC should clearly impose an obligation on TSOs to allows all BSPs to participate in balancing services provision without having a contract for balancing capacity
- The NC does not respect the timelines of implementation defined by the regulator and, to some degree, introduces a legally unenforceable framework based on a voluntary approach. This will probably reflect in a long and complex process that will not enable the rate of deployment of RES required to meet renewable energy and climate targets.

Apart from the above-mentioned issues emphasized by ACER, the following implementation aspects related to the current version are still pending:

- Proposals of lists for standard products[10] for balancing capacity and for balancing energy for FRR and RR, as well as the definition of a common pricing method for standard products for balancing energy[11];
- Proposals for the implementation of the models for the exchange of balancing services[12] (see Table 4.1);

[10] Article 29
[11] Article 39
[12] Article 14(3), Article 16(4), Article 18(4) and Article 20(3)

- Establishment of a common activation optimization function and definition of rules for the activation of balancing energy bids;
- Definition of detailed methodologies for the application of processes to reserve cross-border transmission capacity[13], including the cross-zonal capacity pricing method, the firmness regime of the allocated capacity and, the method for sharing congestion incomes;
- Main features for imbalance calculation, imbalance pricing, and imbalance settlement period to be harmonized[14]
- Criteria and methodology for cost-benefit analyses to be performed by TSO when defining the above-mentioned aspects.

# 5 Bottom up deployment of the Target Model

## 5.1 The Regional initiatives (RI)[15]

The European energy regulators have been working together for many years to promote regional cooperation and the integration of energy markets. The Regional Initiatives (RIs), launched by the European Regulators Group for Electricity and Gas (ERGEG) in 2006, aimed at bringing together national regulatory authorities (NRAs), transmission system operators (TSOs) and other stakeholders in a voluntary process to advance integration at the regional level as a step towards the creation of a well-functioning Internal Energy Market (IEM). The RIs represent a bottom up approach to the completion of the IEM. Seven regional initiatives have been defined, which are based on seven European regions partly overlapping: Central West European RI, North (North Western, initially) European RI, France-UK-Ireland RI, the Baltic RI, the Central South RI, the South West RI, and the Central East RI.

[13] Article 45, Article 46
[14] Article 21(1), Article 21(2) and Article 21(5)
[15] Source: www.acer.es

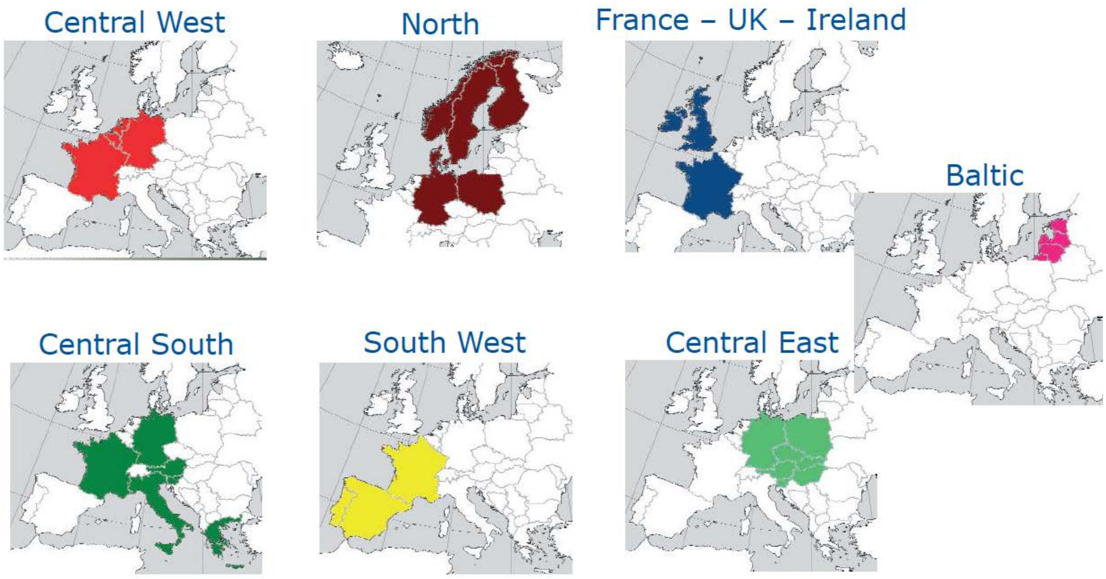


Figure 5-1: Regions defined for the ERI (Source: ACER)

With this strong common vision and these clear Target Models, ACER started applying in cooperation with all stakeholders its new vision for RIs based on a more project-oriented, pan-European approach, a strong stakeholders' involvement and adequate governance structure.

The National Regulatory Authorities involved have produced, at the European Commission's request and coordinated by ACER, an EU Energy Work Plan for 2011-2014 based on clear, commonly agreed objectives and milestones

## 5.2 The EU Energy Work Plans

The EU Energy Work Plan for 2011-2014 in Electricity is constituted by four cross-regional roadmaps focusing on the implementation of the target models for CACM across Europe. It is complemented by seven regional roadmaps detailing the cross-regional roadmaps and focusing on other important dimensions for the completion of the IEM. Each cross-regional roadmap is dedicated to one particular timeframe or topic:

- Implementation of a single European price market coupling model;
- Implementation of a cross-border continuous intraday trading system across Europe;
- Implementation of a single European set of rules and a single European allocation platform for long and medium-term transmission rights;
- Implementation of fully coordinated capacity calculation methodologies and particularly the flow-based allocation method in highly meshed networks.
- Integration of Electricity Balancing markets

## 5.3 Updates based on the reports monitoring the implementation status

There are several periodic publications that contribute to providing a comprehensive outlook of the status of regulatory principles and guidelines making the Target model. These publications include: the Electricity Regional Initiatives Quarterly Reports; the Regional Initiatives Status Review Reports; and the Market Monitoring Reports. All of them are published by ACER (Market Monitoring Reports are published jointly with CEER), though their range of topics they cover and their periodicity varies from one another:

- **ERI Quarterly Reports:** Published every quarter of a year. The first objective of the Quarterly Report is to monitor the implementation of each cross-regional roadmap and to ensure that any obstacle is well identified and can be tackled in the most effective and efficient way. The second objective of the Quarterly Report is to assess progress against the 2014 deadline and for markets which won't be able to meet this deadline to make sure that the delay will be as limited as possible, (For more information: ACER Coordination Group for Electricity Regional Initiatives, 2014).
- **Regional Initiatives Status Review Reports:** These are published annually. These reports monitor the progress made by regional initiatives in the implementation of the principles and guidelines developed at European level to advance in the integration of markets in Europe and increase their efficiency. They discuss the progress made regarding each of the cross-regional roadmaps, or network Codes, defined, (For more information ACER, 2014c).
- **Market Monitoring Reports:** these are also published annually. These are wider reports than the two previous types. They cover all aspects related to the development of EU electricity and gas markets in the corresponding year ranging from retail markets and consumer issues, to network access issues, going through wholesale market integration ones, (For more information ACER/CEER, 2014).

Next, the status in the deployment of the cross-regional roadmaps and Network Codes, based on the information published in the previously mentioned reports, is described. Most updated information collected dates from the end of the first quarter of 2014 (end of the time span covered by the latest quarterly report published).

### 5.3.1 Single European price market coupling model

Aspects to care about concern the determination of the amount of capacity made available to the market in the day-ahead time frame; the implementation of the algorithm itself; and the financial settlement corresponding to the market clearing among PXs and between these and TSOs. The efficiency in the use of interconnection capacity has increased on all those borders where a price coupling solution has been implemented already (2013 Annual market Monitoring report).

The implementation of the price coupling algorithm has already been achieved in the North-Western European region. This is being extended to other regions in Europe. The state of deployment of this by region is listed below:

- **NWE region:** the PCR for this region is running since the 4th of February 2014. The NWE price coupling initiative comprises the CWE, Nordic and Baltic regions (2013 Annual market Monitoring report). The functioning of the price market coupling dispatch is being monitored to check if it is working appropriately. Previously, arrangements were made in 2013 for the deployment of back-up, special and fall-back procedures to be applied if the price coupling algorithm does not provide a satisfactory solution. Additionally, the All Party Cooperation Agreement (APCA) for the operation of the algorithm had previously been put in place, ruling over the allocation of roles and responsibilities for the operational governance and decision making procedures. This should facilitate the extension of price market coupling to other regions. Some aspects of it need to be refined, like the update of loss factors.

- **SWE region:** this is the first region where the PCR solution has been extended to. In preparation for the start of full price coupling, some changes to the functioning of local markets took place in 2013, like the change of the gate closure-time for day-ahead nomination to noon. Tests of the functioning of the algorithm for the start-up solution were conducted in the first 2 quarters of 2014. Full coupling is already taking place (was scheduled to be achieved by 14th of May, 2014).
- **Baltic region:** this region was coupled to the Nordic market on the 3rd of June, 2013. Then, both joined the NWE region on the 4th of February, 2014.
- **CSE region:** some obstacles are being addressed to achieve full coupling soon. These include the shift of gate closure time in all markets to 12:00, the designation of a PX in Austria and the development of a market in Greece. The Greek market will not be ready to operate as of the initially set time window for the launch of the full coupling in this region, but Greece can still work as a contributor (equivalent agent) on the border with Italy.
- **CEE region:** this region is undergoing the implementation phase. Developments being achieved at this stage include the allowance of the selection of a service provider by consumers. The full start-up of the price coupling solution was scheduled for the end of the year 2014. However, we have not got confirmation it has gone live.
- **Croatia:** a power exchange (PX) with PCR capability was scheduled to bet set up by the end of 2014, though there is no precise timeline of the coupling with neighboring systems.
- **Ireland:** Consultations on the design of a new market have taken place throughout the year. Its definite design is being advanced.
- **SEE region:** prospects of having achieved the price coupling of this region in the year 2015 are unclear. Day-ahead markets already exist in most systems with the region and the launch of a regional PX in Serbia should have taken place by the end of the year 2014, though the participation of local TSOs and PXs from other systems in this regional solution is still unclear. Macedonia and Croatia are working towards the creation of a local PX.

### 5.3.2 Cross-border continuous intraday trading system

The implementation of an Intraday common Trading system should result in an increase of efficiency in the use of available interconnection capacity in this time frame. Integrating RES generation requires having available a large enough amount of flexible resources. One alternative to achieve this is through an adequate, integrated pricing of flexibility in intraday and balancing markets (2013 Annual market Monitoring report). The evolution of this specific initiative is then crucial regarding an efficient increase in the level of integration of RES generation.

Some progress on the deployment of an intraday market was achieved during the year 2013. Thus, the provider of IT to deliver the intraday platform was selected then, and the European Commission took the lead to guide the process of deployment of this market. Initially, a continuous intra-day trading system was scheduled to be implemented on all borders by the end of 2014. However, the implementation process has been delayed and the deadline not met. The process is expected to start with the deployment of continuous implicit trading covering the NWE region plus Austria and Switzerland and should be extended to other regions while being adapted to meet all requirements of the solution initially envisaged.

The level of development and deployment of the intraday solution in each region is described below:

- **NWE region:** power systems in this region have entered an Early Start Agreement whereby they should define the foundations of the continuous intraday trading scheme and define the design of the trading platform. Getting to an agreement on some main design issues of the trading algorithm has caused significant delays leading to the possibility that the deadline (end of 2014) will not be met once they are solved. Power systems in the region should set the terms and conditions for the design, development and deployment of the trading solution in the frame of a Power Exchanged Cooperation Agreement (PCA).
- **SWE region:** the letter of comfort addressed to Spanish authorities was approved by the regulator and submitted to the Spanish PX. There is no implementation roadmap that we know of.
- **CSE and CEE:** there is no implementation roadmap yet that we know of.
- **SEE region**: generally speaking, no measurable progress had been achieved in the implementation of the regional market in March 2014.
    - **Croatia (within the SEE):** the regional intraday market is to be set up in Croatia after the implementation of its day-ahead market and coupling with others in the region. This will not take place before mid 2015. The design of intraday rules and their implementation is being undertaken in some system in the region like Hungary. By the end of the year 2014, only the intraday allocation of capacity on the border between Croatia and Bosnia-Herzegovina was expected to be in place.
    - Romania, Bulgaria: there is no implementation roadmap.
- **Ireland:** consultations on the design of the market taking place.

### 5.3.3 Set of rules and allocation platform for medium and long term transmission rights

Transmission rights should be developed to give the possibility to market agents to hedge against mid to long term grid congestion price volatility in the day-ahead time frame. In order to enable trading of transmission rights across all the IEM, parties are working on the harmonization of allocation rules, the platform to be used for the trading of rights and the nomination procedure for rights. The move from physical transmission rights (PTR) to financial transmission rights (FTR) is also being dealt with.

Traditionally, two designs have been applied for the allocation of forward products in Europe. One was set up in the Nordic region, the Baltic countries, and the internal borders of Italy. It implies the trading through a pure market mechanism of contracts related to the price of electricity in a single hub for the whole region. This price represents a sort of average electricity price for the whole region (single zone hub). The other design, which was applied in most Continental-Europe countries, involved the determination of available capacity at each border and the allocation of this capacity to market agents in the form of Transmission Rights. This approach relied on TSOs to carry out this process and allowed the hedging of the price of electricity in each bidding zone (multi zone hub) (2013 Annual market Monitoring report). Two relevant trading platforms emerged for the trading of transmission rights under this second approach: the Central Auction Office and the Capacity Allocation Service Company (CASC).

Transmission capacity auctions have not behaved in a fully efficient manner generally speaking, since a negative risk premium (negative difference between the price paid for transmission rights and the difference in the day-ahead price between those zones that these transmission rights refer to) has been obtained. The value of this risk premium was below -1 on most borders among European states between 2011 and 2013.

In 2013, relevant authorities had already agreed to make available transmission rights on most borders long-term. Also in 2013, the two regional operators of a transmission rights allocation platform (the Central Auction Office and the Capacity Allocation Service Company) signed a memorandum of Understanding setting the main principles for the creation of a single auction platform. However, some discrepancies among ENTSO-e, ACER, and the NRAs have persisted over a long time on the set of rules to be applied to auction transmission rights. As already mentioned, these entities are working on the definition of commonly accepted rules.

Concerning 2014 (at least the beginning of it), the progress being made region-by-region is described here below:

- **Baltic:** auctions of yearly and monthly PTRs on the Estonia-Latvia border are already developed. This may not comply with EU regulation and is a temporary solution in the process of allocation of financial rights. Rights have not been allocated yet on the border between Latvia and Lithuania.
- **Northern region**: Transmission rights have not been allocated yet on the Norned, Baltic cable, and Swepol link. The allocation of physical rights in the border between bidding zones within Denmark was scheduled for the beginning of 2014, and the shift from PTRs into FTRs was to be studied later on.
- **SWE region**: transmission rights in the form of financial rights are being allocated already on the Spain-Portugal interconnection and in the form of PTRs on the border between Spain and France. Both are medium term rights allocated since March in their new form. Future developments include the allocation of long term rights, scheduled to take place from the

year 2015 on, and the issuance of FTRs (shadow auctions) on the France-Spain border from March 2015 on. UIOSI rules on the FR-IT border to be adapted to the day-ahead coupling. Spain-France border to join CASC scheme with no defined timeline.

- **CSE region:** UIOSI rules on the FR-IT border has to be adapted to the day-ahead coupling. Roadmap for the harmonization of auction rules affecting IT with those in the CEE region (defined through the auction office in CEE region, termed CAO) still not defined.
- **CEE region**: rules to harmonize auction and platform in IT with CASC have to be defined. Northern-Croatian borders are to be included still in the CEE region auction rules (CAO).
- **France-UK-Ireland (FUI region):** Interconnexion France-Angleterre (IFA) rules applied to the FR-GB interconnector since the implementation of price coupling in NEW region. There are no plans yet to implement a harmonized set of allocation rules.
- **SEE region**: at the beginning of 2014, there were prospects for a Central Allocation Office and coordinated long term auctions to take place in the region throughout 2015. However, these would only include part of the TSOs in the region, since not all of them were participating in the central Allocation Office for the region.
    - Croatia: similar situation for borders with Slovenia and Hungary as with the CEE region as of March 2014.
    - Romania, Bulgaria: no roadmap for a harmonized set of rules at the beginning of 2014.
- Ireland: no roadmap for harmonized platform or set of allocation rules.

### 5.3.4 Capacity Calculation methodologies and Flow-based allocation method in meshed networks

The allocation of transmission capacity on the corridors defined within the transmission grid, either explicitly in transmission capacity auctions (for transmission rights) or implicitly in the form of day –ahead market coupling processes, should allow an accurate representation of real flows occurring among areas as a result of agreed transactions.

The lack of accuracy in the definition of bidding zones results in loop flows (LFs), or internal power exchanges in a zone affecting the flows on some regional corridors. The lack of accuracy in the representation of flows produced by inter-zonal transactions results in Unscheduled Transit Flows (UTFs) crossing the grids of third countries while not being accounted for when allocating transmission capacity. Both types of flows have traditionally, and increasingly, resulted in significant efficiency losses resulting from the application of congestion management solutions, amounting to about half a billion Euros in 2013 (2013 Annual market Monitoring report). Traditionally there has been a lack of transparency about the size of unintended flows and the remedial actions taken to deal with them. The 'transparency regulation' adopted in 2013 should provide more information on these, (2013 Annual market Monitoring report).

As explained in section 3, there are two different possible schemes for the allocation of transmission capacity on the corridors among bidding areas in the common network model to be used for CACM purposes: the Available Transfer Capacity (ATC) and the Flow Based (FB) methods. The ATC is simpler but less efficient in meshed grids than the FB method. The Northern, SW, CSE, and FUI regions have decided to apply an ATC for the allocation of capacity among transactions. This makes sense in most of the previous cases, as interconnections among systems in these regions are mainly radial, but does not make sense in the CSE region, where LFs and UTFs are very relevant.

For the rest of regions, progress made in the deployment of FB solutions is discussed next:

- **Baltic**: not clear yet which available capacity calculation scheme will be implemented (as of March 2014).
- **CWE region**: parallel runs of the foreseen FB scheme had started being conducted successfully in February 2014. These runs involve publishing day-ahead market coupling results simulated with using the Flow Based capacity calculation method. The launch of the full FB solution (its full application), which should be reliable and accurate, was scheduled for the end of 2014 (November). The achievement of this target depended on 1) the success of parallel runs, 2) the launch of a consultation process in mid 2014 to check the views of market parties and address their concerns, and 3) the ability to address concerns related to the transparency of the method, the ability of NRAs to monitor the functioning of the method as well as the impact of the value set for parameters playing some role in the application of the method; and the allocation to systems of the congestion income resulting from the application of the day-ahead solution.
- **CEE region:** TSOs and PXs have agreed on the basic terms of reference for the deployment of a FB solution (Memorandum of understanding), as well as the creation of a joint committee to drive the design and deployment of the FB solution for day-ahead market coupling. Roadmap to deploy this solution needs to be revised (delayed). Unscheduled flows existing in this region have delayed the deployment of a solution.
- **Ireland:** as for other market aspects, authorities are working on the design of the model features.
- **SEE region:**
    - Bulgaria: still no decision about capacity calculation.
    - It is unclear whether 2015 targets will be met. The grid model for the region has been updated and there is a method for the long term coordinated capacity calculation.

### 5.3.5 Integration of balancing markets

The integration of balancing markets in Europe could potentially bring about savings in the order of hundreds of millions of Euros in system operation costs. Among other benefits, it would make possible an efficient increase in the amount of RES generation integrated in the system. Integrating RES generation requires having available a large enough amount of flexible resources to be able to balance changes in the power output available from variable RES generators. This can only be achieved through an adequate and integrated pricing of flexibility in intraday and balancing markets (2013 Annual market Monitoring report).

Regarding the development of regional balancing markets, the Target Model is pursuing two objectives:

- Strong coordination of TSOs to achieve an efficient sizing and exchange (sharing) of balancing reserves, as well as an efficient activation of balancing energy. According to initial provisions, the activation of balancing energy is to be carried out according to a TSO-TSO common merit order both for manually and automatically activated frequency restoration reserves (FRR) and for manual replacement reserves (RR)
- Provision of well designed market incentives to drive market agents to behave efficiently in the balancing market. Incentives provided concern:
    - Harmonized price signals for the provision of balancing energy by Balance Service Providers.
    - Harmonized requirements on terms and conditions to participate in the market that should facilitate the participation of demand and RES generation as service providers.
    - Common features for the efficient settlement of energy imbalances affecting Balance Responsible Parties.

In order to achieve these objectives, ACER invited ENTSO-e to undertake several pilot projects. These are being arranged through a Balancing Pilot Stakeholder Group, which shall monitor the progress made with these pilot projects and, arguably, also about the design and development of a balancing market model.

Progress made with the several pilot projects is summarized next:

- Pilot 1 (German TSOs) is merging, at least partly, with pilots 5 (Nordic) and 7 (NL/BE). They focus on manually and automatically activated FRRs.
- Pilot 2 (DE, NL, CH) is not merging with other projects, despite TSOs in the three systems use a common platform for the procurement of FCR, which is allowing Germany to provide some reserves to NL and CH.
- Pilot 3 (CZ, HU, SK) will not merge with other, including pilot 9, due to contractual and IT arrangements.
- Pilot 4 is possibly merging with Pilot 8, both being focused on restoration reserves affecting BritNed and TERRE. But Pilot 8 must first deal with differences in market design between GB and NL.
- Pilot 6 will go on being deployed, but not as a pilot projects.
- Pilot 9 is allegedly cooperating with Pilot 1 on the usage of the same optimization function. The two have been artificially defined as two different projects, though they both concern the TSO areas in Germany.
- Regional Pilot 8: this concerns the development of a balancing market for the SEE region.

# 6 Assessment of the Target Model

Here the reader is informed about the extent to which the TM is expected to address main challenges lying ahead in the development of the IEM in a context of high RES penetration. The three pillars of the EU energy policy should be mentioned as a start of this discussion: Security of Supply (SoS), efficiency, and sustainability. Achieving these objectives requires the deployment of some products:

- Low emission energy
- Capacity (and more specifically firm capacity)
- Flexibility

Furthermore, Member Sates decided in 2008 for RES target by 2020 and are currently discussing a RES framework for 2030. This implies that RES will have a crucial role to play in relation to these 3 pillars. Thus, the main question to be answered is whether the TM is able to deal satisfactorily with the contracting of products required in each time frame (long, short and very short term), and whether the contracting of these products under the TM is going to take place in an efficient way. Different products are to be delivered in different time frames. Thus, the assessment of the model can be conducted for each of these time frames, separately.

## 6.1 Long term

As already pointed out in the introduction to this section, within each of the different market time frames considered, an analysis is made of the ability of market designs considered in the TM for the provision of required products.

For the long term, the most relevant issues discussed are the approaches to deal with long-term security of Security of Supply (through the energy only market or through additional Capacity Remuneration mechanisms) and the procurement of clean energy provided by RES generation.

### 6.1.1 Capacity Remuneration Mechanisms (CRM)

**Status quo of CRMs in Europe**

Europe is immersed in a debate that is reshaping its short to long-term electricity markets. As reviewed in previous sections, the EU target model is currently being mainly developed towards he harmonization of short-term wholesale markets.

In parallel to this harmonization process in the short term, the generalized lack of trust in the energy only markets and the difficult financial situation of some electricity players is prompting governments towards reconsidering the need for implementing a Capacity Remuneration Mechanism (hereafter CRM). A combination of different market failures (e.g. residential demand does not participate in the markets) and regulatory failures (e.g. price caps and high regulatory risk) are behind this major problem.

ACER's examination of capacity remuneration mechanisms and the internal market for electricity, published in 2013, set out a classification of CRMs (Figure 5-1).

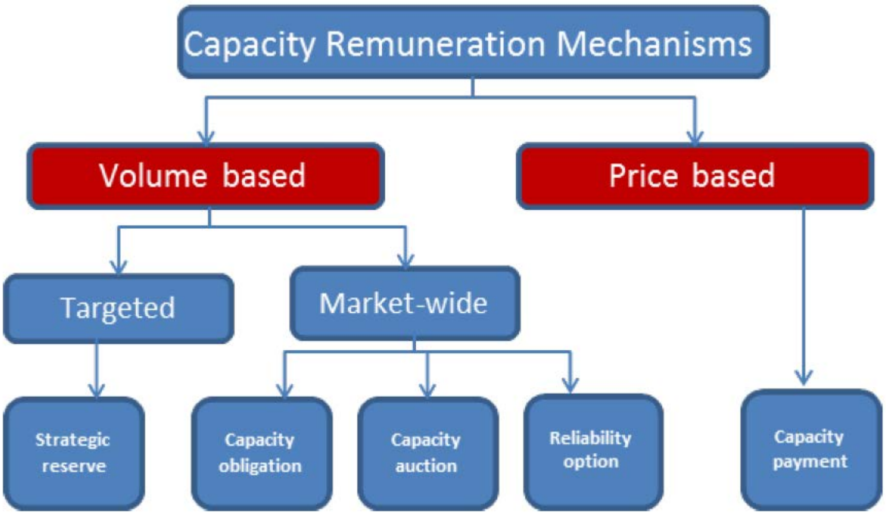


Figure 6-1-Taxonomy of CRMs, Source: ACER, 2013.

In the same document, it is also presented the state of capacity mechanisms across Europe at that time (see Figure 6-2). The picture shows how, after decades of strong opposition, several European countries have implemented CRMs.

In the last year there have been some relevant developments, with Belgium and France having adopted a Capacity Market and Italy and Ireland having defined new volume-based mechanisms[16] that will substitute the previous capacity payments. On the other hand Germany, the largest European electricity market, is close to implement a mechanism based on the Strategic Reserves.

**The concern of a non-coordinated solution**

Unfortunately, in the particular issue of Security of Supply and CRM mechanisms, the national initiatives have been clearly one step forward than the European regulation. As well-know, aiming at energy autarky rather than seeking a wider regional coordination can significantly affect the potential benefits of an integrated long-term expansion of the European power system. This situation has raised the Regional Authorities alarms, who precisely perceive these national movements, if not properly coordinated, as a potential threat to the proper development of the Internal Electricity Market.

[16] Both based on the Reliability Options.

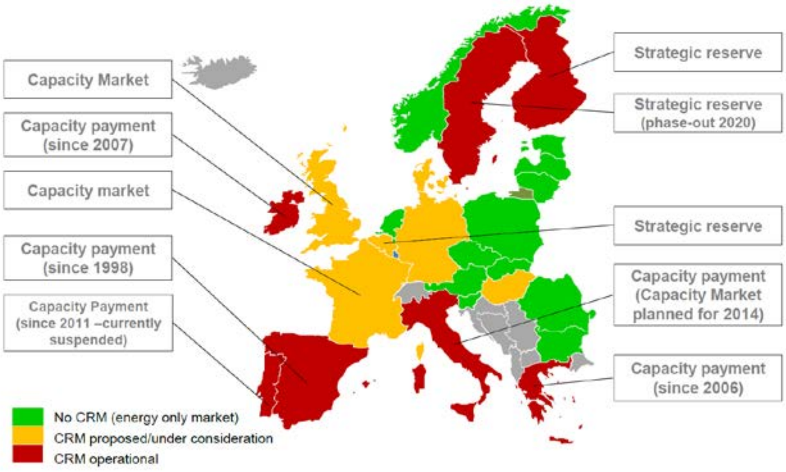


Figure 6-2.-Status of capacity remuneration mechanisms in Europe, Source: ACER, 2013

Particularly, concerns on this issue have been expressed in several documents released in the last years by key EU institutions. Just to mention some of the most relevant[17]:

- In EC (2012): it is stated that "if capacity mechanisms are not well designed and/or are introduced prematurely or without proper coordination at EU level, they risk being counterproductive" and that "poorly designed capacity mechanisms will tend to distort investment signals".
- In ACER's opinion (ACER, 2013): "It is essential that any capacity remuneration arrangement does not unduly interfere or distort the functioning of the energy market and does not delay the completion of the IEM". It is also observed that the "lack of coordination (on generation adequacy measures) has resulted in a patchwork of CRMs in the EU, which may be at the detriment of the market integration process".
- EURELECTRIC (2013) outlines as a key message that "CRM should be open to cross-border participation, underpinned by close coordination between Member States and respective system operators (TSOs)".
- Finally, EFET (2013) underlines that CRMs have to be "non-discriminatory, by taking into account the contribution of non-national generation through interconnection which may decrease local needs".

The fact is that the integration of markets implies that security of supply (including generation adequacy), is increasingly difficult to ensure on a purely national basis (EC, 2013).

[17] See (Mastropietro et al, 2014).

## The EC guidance to solve the Security of Supply problem in the Regional context

The European Commission, in their staff working document (EC, 2013), points out a guidance to properly ensure generation adequacy in the internal energy market[18]. This guidance includes four major points:

- As a starting point, the energy only market should be given an opportunity to do its job encouraging appropriate investments.
- In parallel, public authorities must undertake an assessment of the generation adequacy situation in their Member State.[19] This assessment needs to fully take account of developments at regional and Union level, the effect of European policy objectives, and the potential of demand response[20].
- Where a concern about generation adequacy emerges, its causes should be properly identified, including policy uncertainty and failures in regulation at the national level. Where possible, such causes should be removed.
- Member States, when intervening to ensure generation adequacy, should choose the intervention which least distorts cross border trade and the effective functioning of the internal electricity market. Such an approach will help ensure that interventions are also cost effective.

In the following, we briefly deal with two major problems that underlie the Commission guidelines: (i) analyze the real need for CRMs, or in other words, the capability of the energy only market to ensure security of supply, and (ii) if CRMs are needed, how to properly design them so as not to affect efficient cross-border trade.

## The energy only market capability to ensure security of supply

The starting point set by the EC is to let the market provide efficient price signals. The mistrust on the ability of the market, left to its own devices, to provide sufficient generation availability when needed has been a concern since the outset of electricity markets.

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[18] Without prejudice to additional guidelines on State aid in the energy and environmental fields.
[19] This is required by Directive 2005/89/EC 7 (the Electricity Security of Supply Directive). With respect to this requirement, ENTSO-e (2013) points out that "while it is noted that there are significant difficulties in standardizing generation adequacy analyses methodologies across internal market because risks on Security of Supply originate from structurally different issues, there would be a clear benefit in reporting in a systematic harmonized fashion the key security metrics across the internal market".
[20] It is needed to assess to what extent consumers/energy service providers/aggregators in the European system are incentivized to install the equipment needed to manage load in order to reduce power consumption whenever needed for security of supply reasons.

As widely analyzed in the literature, there are many experiences and reasons why markets failed to provide investment signals. Very briefly and avoiding entering into any academic detail, fully relying on an energy only market to solve the adequacy issue entails (among others):

- Developing a proper scarcity pricing methodology and then allowing the system to reach price spikes in times of scarce supply. The plans to implement a homogenous EU-wide 3000 €/MWh price cap goes in this direction. However, this price cap has been considered as not enough to reflect the opportunity cost in times of scarcities in other markets. For example, in the Electric Reliability Council of Texas (ERCOT), the price cap has been set at 7000$/MWh at the time of this writing (and it is expected to increase to 9000$/MWh in 2015).
- Ensure that there are well-functioning long-term markets, providing products that enable efficient risk management. The robustness of the forward/future markets in each particular wholesale market needs to be investigated.
- Ensuring that investment lumpiness is not a problem (this can affect to a larger extent smaller systems).
- Avoid the regulatory risk. There are no effective long-term contracts in forward markets against regulatory changes. The only solution is long-term contracts issued by the regulator itself. This is claimed to be one of the most relevant problems today.

Whether the ideal conditions for the well-functioning energy only market can be achieved, is something that will have to be analyzed on a system by system basis.

*The need to distinguish between the missing money problem and the capacity problem*

The Commission (EC, 2013) explicitly calls for distinguishing between the missing money problem (i.e. agents not being capable to currently recover their investments) and the missing capacity problem (i.e. there is not enough capacity to meet demand needs). According to the EC, mechanisms are not to solve the missing money problem due to overcapacity but rather to solve the capacity problem.

- *"Currently, there is overcapacity in many markets [...] creating market wide capacity remuneration schemes may under such circumstances be counterproductive as it may (depending on the criteria set for capacity to participate in the scheme) postpone the exit of inefficient capacity from the market." "In liberalised markets, investments are not guaranteed by the State. Only where there is a real threat to generation adequacy and security of supply as a result of closure or mothballing does the financial viability of existing plant become a matter of public concern. It is very important that there should not be state support to compensate operators for lost income or bad investment decisions. "*

*CRM implementation is already a fact in some power systems*

In some systems the implementation of (diverse) CRMs is already a fact. One of the major concerns in this context is how to refine the current regulation to allow for a proper development of the EU internal market for electricity. The current problematic situation is briefly analyzed in the next point, and will be given further attention in WP3.

**The cornerstone: the need to ensure cross-border participation in CRMs and current practical barriers**[21]

The Commission points out that in order to minimize distortion and also ensure cost-effectiveness, CRMs should be open to all capacity which can effectively contribute to meeting the required generation adequacy standard, including from other Member States.

There are different alternative ways to include Member States contributions. Generally speaking, imports can be accounted for in the CRM mechanism either implicitly or explicitly.

- Implicit consideration entails merely taking into account the statistic contribution of Member States. This is for example the approach that has been taken in the first auction called in the context of the UK's CRM.
- Explicit consideration involves signing reliability contracts with neighbors. Explicit participation allows to obtain larger benefits but also involves a higher level of complexity.

This higher complexity of explicit participation comes from the fact that there will be a financial and or physical commitment with a generator in another Member State. To effectively deal with this commitment it will be needed in some cases the presence of well-developed long-term cross-border products. But more importantly, in order to explicitly include generation from a neighboring system in a capacity mechanism, the TSO of the country launching the CRM (the CRM-system) must be sure that, during scarcity conditions, the foreign generation has to be able to fulfill its physical supply commitment linked to the capacity mechanism. Unfortunately this is not currently the case, basically because of two reasons.

- The first reason is related to the mistrust of the fulfilment of article 4.3 in the Security of Supply Directive (2005/89/EC), when it states that "in taking the measures referred to in Article 24 of Directive 2003/54/EC and in Article 6 of Regulation (EC) No 1228/2003, Member States shall not discriminate between cross-border contracts and national contracts". This mistrust is based on the existence in most electricity laws and national network codes in force in the Member States of clauses that maintain that exports to other countries will be interrupted in case of a domestic emergency of supply. Therefore, in case of concurrent scarcity conditions, the TSO of the foreign country will surely limit the flow through the interconnection, thus impeding the foreign agent to fulfil its capacity mechanism contract.
- The second reason is that a strict application of the so-called Target Model would result in the automatic allocation of the entire transmission capacity through the short-term market clearing algorithm, being the flows through the interconnections determined by the equilibrium between generation and demand in the different zones. This approach would

[21] This section relies on Mastropietro et al, 2014.

could impede the fulfilment of capacity mechanism contracts by foreign agents during system stress events (particularly, this could be the case when there are concurrent scarcity conditions). If this is the case, it is even possible that, during these concurrent scarcity conditions in the regional system, national generation which could have committed in the CRM could “slip out” through the interconnection driven by price differentials with neighboring countries. This would mean that the presence of cross-border interconnection could increase the amount of capacity to be procured and could result in overinvestment in the country implementing the CRM.

### 6.1.2 Low emission energy (deployment of required RES generation through several possible mechanisms)[22]

From the EU energy policies, it can be expected a long term renewable support, together with market competition. That means that RES will take part in the Market as any other technology.

The TM will have to provide these economic operation price signals, to ensure that Short Term operation is always scheduled in the most efficient way. Most probably, generators will have a schedule from either forward markets or day-ahead markets and will have the chance to modify it within intradaily or ancillary services markets. The TM must ensure that these markets and services are appropriate to provide efficient operation signals. There will be a true-up afterwards when deviations from scheduled energy will have to be paid. Deviation prices should be cost-reflective and must be paid by any generator (RES or any other technology) or demand.

But the TM must as well provide investment signals in the long term. There are evidences that energy only markets do not present enough incentives for RES investors, a parallel can be drawn with the discussion in section 6.1.1. The concept of price cannibalization by RES has been already seen in several countries. According to it, prices earned by RES generation in short term energy markets are significantly lower than average ones. This is due to the downward pressure on prices produced by RES generation bids, which are very low (in line with their variable production costs), and replaces in the energy dispatch more expensive generation setting the market price in hours where RES power production is scarce. Forward markets do not provide a solution to this problem. Prices in well functioning forward markets should reflect the value that energy contracted in the long term should have in the operation time frame, i.e. they will reflect the expected value of that energy in the short term market. Hence, given that the price at times when RES power production is abundant is significantly lower than average prices, prices earned by RES generators selling their energy in forward markets should be low. Therefore, although forward markets should be strengthened on a general basis, they may probably not provide strong enough signals for investments in RES generation.

[22] CO2 pricing mechanisms, which are an alternative to direct RES-subsidy, are not discussed here.

There may, therefore, be a missing clean energy incentive if the mechanisms to attract large enough amounts of RES generation are not put in place. This may, of course, affect to a larger extent some generation technologies than others. Thus, a large share of the hydro generation is largely competitive due, among other things, to the controllability of its output related to the possibility to store power in water reservoirs. Wind generation is currently close to be competitive in many systems. However, the progressive implementation of ever more ambitious targets of emission reductions may largely aggravate the problem of cannibalization discussed above. This would result in a significant decrease in the average level of prices earned by this type of generation. Achieving the profitability of investments is even more challenging for others technologies, given their low load factors or high installation cost.

Some of the currently existing RES technologies may turn out not to be necessary in the future, since other clean technologies may end up being more efficient in meeting environmental targets. However, there should probably be in place market mechanisms allowing, first, the development of most promising RES technologies, and then the massive deployment of those that would allow us to comply with environmental requirements at the lowest possible cost, see (Olmos et al., 2012). There is a reasonable doubt that currently existing energy markets as promoted in the TM will suffice to achieve this.

The provision of large enough amounts of clean Energy needs to be placed in the wider context of a competitive and efficient, supply of electricity in Europe. This exercise is needed to ensure an efficient, safe and sustainable functioning of the system, both now and in the future. Thus, if market designs currently envisaged in the TM are not able to guarantee the appropriate amounts of generation capacity from the portfolio of RES technologies that will be needed in the future, complementary markets may need to be implemented. This should not come as a non market based support for RES generation, but as market mechanisms allowing authorities to match the supply and demand in the system for the needed products.

Currently, the TM is only considering the existence of energy and balancing markets in the short and very short term complemented by the sale of transmission capacity products in the long term. However, additional long term markets may need to be developed to ensure investment in RES generation. Just like it may have to be developed to support the deployment of capacity of other technologies providing firm capacity, possibly in the forms of CRMs. RES generation deployments would have to be organized through a competitive mechanism (auctions, for example), which should be designed to determine which facilities are to be built and the income that they need.

This way, the TM shall allow market agents to have several sources of income related to the several products they provide depending on their features. Together with the energy market income, there might be an income related to the firm capacity provided, another income that might depend on the manageability of the facility, or another one that will correspond to the sale of clean energy. These incomes could probably take the form of products traded in a long term market arrangement.

By providing the appropriate sources of income, the TM should produce strong enough signals for investment in technologies with the desired characteristics, providing either firm power, energy or flexibility. For example, if a system needs to ensure the provision of balancing power already in the long term, the Target Model should create a way to ensure the coverage of that need. As all technologies shall compete freely, all might get a higher or lower income from different markets, plus the income they may get from the energy market based on short terms operation prices. Logically, some technologies will receive a higher share of total income from one side, whilst others will obtain revenues from other sides, depending on the characteristics of each technology.

The need for additional markets to the short and very-short term energy and balancing ones, as already included in the TM, is assessed in the current section (6), as well as later in the project in WP4 and WP5. Another relevant issue to address is whether additional long term clean energy markets should target specific technologies or, rather, they should just foster competition among all clean technologies. A framework where all these technologies would bid the incremental amount of revenues they would need to cover the cost of providing a certain amount of clean energy. One should be aware that all markets devised should be designed to work smoothly together. However, targeting specific clean technologies may be needed to foster the deployment of promising technologies that, have not achieved by then a high enough level of maturity.

#### 6.1.3 Provision of flexibility in the long term

Agents must be free to evaluate themselves how to take part in each market, or, for instance, the benefits of investing in equipment needed to manage their load to provide balancing energy. And then, decide whether it is worth or not to make that investment decision. The TM must ensure that the most efficient solution is used to provide required services, regardless the technology employed for this. It must encompass the development of markets and services adapted to the technical capabilities of the agents, showing service demands and/or price signals that encourage agents to evolve in line with the needs of the system.

Then, balancing markets in the short term need to be assessed regarding whether long term signals they produce are strong enough to drive the installation of flexible generation or equipment needed for load and generation to provide the balancing services that will be required. Prior to this, short term balancing markets should be reformed to work efficiently. Again, the functioning of all markets should be assessed in an integrated manner, since revenues produced by them combine to create operation and investment incentives for agents. The TM must ensure that all technologies receive a total income proportional to the value of their contribution to required system services, and that no technology is over-paid.

### 6.2 Short term

#### 6.2.1 Target model – as represented by CACM

The development of the target model and corresponding roadmap was initiated by the Florence Forum in 2008. Main pillars include, among other things, integrated markets for day-ahead, intra-day, and balancing by 2014. Whereas the main pillars are still the same, the detailed specification of processes and procedures for achieving those goals, and specific legislation for how the markets should operate, are still under development. Therefore, before actually assessing the adequacy of specific characteristics of the target model, there is a need for clarifying what we actually mean by the target model. In the following we will assess the institutional arrangements as they are drafted in the network code on Capacity Allocation and Congestion Management (CACM) at 5th December 2014 (EC, 2015), which has already been described in details in the section 3.1 .As a reminder, the CACM NC includes specifications i.e. for day-head market and intra-day market, which we call short-term markets in this report, and in particular how cross-zonal capacity should be dealt with in the market-clearing procedures for those markets.

#### Efficient energy trading

Before considering the specifics drafted in CACM, it can be useful to clarify also what we mean by efficient energy trade. In general, allocation of scarce resources is efficient if no so-called Pareto improvement is possible, i.e. it is not possible to improve the welfare for anyone without reducing the welfare for somebody else. However, most changes will produce an outcome that is better for some but worse for others. Therefore, individual utilities are often summarized to total economic surplus i.e. by representing utility by willingness to pay, and the total surplus is then the sum of consumer surplus and producer surplus. The basic idea here is that a Pareto improvement in principle could be obtained through subsequent redistribution of welfare. An efficient allocation will then maximize the total economic surplus for the considered market. If it can be demonstrated that e.g. the total system costs in some cases are not minimized when applying the institutional arrangements (including markets) as specified in CACM, then those arrangements are not efficient.

#### Multi-market setting

The actual production and consumption occurs only real-time, during operation and not day-ahead or even intra-day. Therefore, the concept of efficiency cannot be applied in a meaningful way to an assessment of the day-ahead or the intra-day market without also taking into consideration how other institutional arrangements affects the actual operation of the system after the closing of the short-term markets. For instance, if the TSO is carrying out efficient re-dispatching / countertrade, this can at least partly reduce inefficiencies caused by a single zonal price that do not take into account the exact location – and impacts of how altered injection affects congestion - within a bidding zone. Still, the institutional arrangements for day-ahead and intra-day will have an impact on the final outcome, which can be discussed also in relation to the full multi-market context.

#### Market clearing in CACM

In CACM the development of new roles and functions (e.g. Market Coupling Operator - MCO, Nominated Electricity Market Operators - NEMIs and Capacity calculation regions) are described together with the development of new tools (e.g. individual grid models, common grid models, generation shift keys) and some structure for the actual optimization procedure to be carried out in the end (e.g. equal price in zones, flow-based optimization, integration of adjacent capacity calculation regions). Figure 5-3 is an interpretation of some of the structure, which is lined up in CACM. However, we do not claim that this is the exactly intended or only possible specification in consistence with CACM.

First of all, with relevance for efficiency, a regional optimization is carried out for each of the capacity calculating regions, which are merged when possible. The regional optimization is carried out by the MCO – or rather it is a MCO function that can be assigned to power exchanges in practice. The regional optimization maximize social welfare, subject to specified generation shift keys (when deviating from a forecast which the system is calibrated towards), balance constraints for changes in net positions of different zones, and flow-based constraints identifying flows on specific elements as a function of initial flow, changed injection and so-called Power Transfer Distribution Factors (PTDFs) that maps from injection to flows. The welfare is calculated by utilizing submitted bids which are collected by NEMIs, which in practice are power exchanges. The TSOs are providing forecasts for net injection and generation shift keys (to derive which units will actually adjust injection if net position for a zone is adjusted), whereas the flow-based constraints are built up by utilizing a common grid model for Europe that will be built up by individual grid models as submitted by national TSOs. The TSOs also decide the security margins in which the flow can be operated, and they provide the location for units in each zone to be mapped in the individual grid model they provide. The outcome of the optimization is a set of net balances for each bidding zone. This information is then utilized by NEMIs to calculate the balance price for each bidding zone, and only one market-clearing price is calculated for each bidding zone. The exact configuration of capacity calculation regions and possible within-region bidding zones are not specified in CACM. However, the process involving TSO cooperation for agreeing upon regions and bidding zones is described. Also, formal procedures for solving disputes if necessary as well as revisions of the configuration of the system are described.

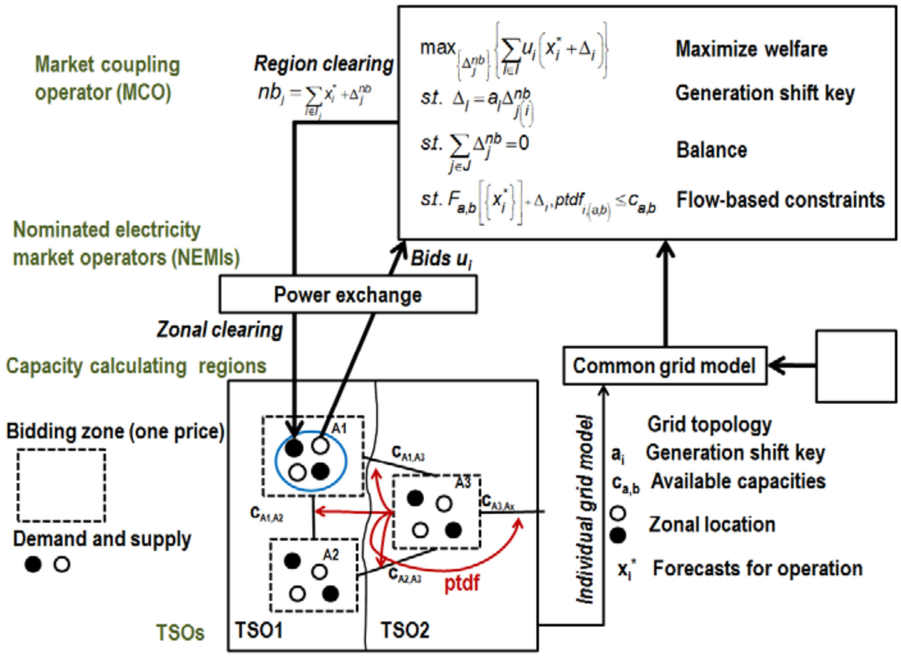


Figure 6-3 -An interpretation of the market-clearing process described in CACM

As illustrated in Figure 3, CACM indicates a procedure where the net injection for each bidding area is optimized, subject to a predefined generation shift key for each bidding zone that distributes calculated injection changes to specific within-zonal locations/units. By calculating the generation shift key on basis of a single zonal price, the zonal price becomes in reality a constraint in the flow-based optimization carried out by the MCO. In an ideal optimization, however, there could be a unique price for each location in the pan European grid model. Then the MCO optimization would have to optimize each individual net injection (generation minus consumption), and then apply the individual PTDFs to calculate effects of altered injections on congested transmission lines.

### 6.2.2 Is the indicated model efficient?

The MCO maximizes welfare subject to bids, balances, flow-based constraints (if applied) and generation shift keys. This is very close to the definition of an ideal cost-efficient allocation in a power system including detailed power-flow constraints. The question is therefore not if mechanisms for providing efficiency are taken account; those mechanisms are obviously included. Therefore, the question is rather if the allocation could be improved further by adjusting the indicated system somehow. In the following, we discuss the two methodologies for calculating cross-zonal capacity, and the utilization of bidding zones is a possible source of inefficiencies. An interesting analysis of the efficiency driven by the TM is provided in (Keay, 2015).

**Flow-based methodology versus Coordinated Net Transmission Capacity**

The flow-based methodology optimizes the utilization of the grid account taken for the actual flow when changing the injection from specific units or zones, whereas the Coordinated Net Transmission Capacity specifies a predefined cross-zonal capacity which a single-price clearing on each side of the border can utilize in a joint optimization. In order to deal with uncertainties in physical flows, system security margins must be set accordingly. Therefore, the flow-based approach typically allows an increase in cross-order transmission capacity where it is most needed because it more accurately reflects the actual situation in the grid (ENTSO-e, 2015). Both methodologies ensure integration of power markets and coordination in market-clearing and allocation. However, greater efficiency can often be obtained by utilization of flow-based approaches.

CACM opens for utilizing both principles when determining cross-zonal capacity. However, whereas the flow-based methodology is preferred, the coordinated NTC methodology can be applied in special cases (within Capacity calculation regions) where cross-zonal capacity is less interdependent and it can be shown that the flow- based approach would not bring added value. Therefore, unless it can be qualified that the flow-based approach will not bring added value, it shall be utilized. Possibly, the coordinated NTC approach could be considered for some areas on the borders of Europe with a more radial grid topology.

### 6.2.3 Bidding zones

The EU Electricity Target Model envisages a zonal design which addresses network congestions between "properly defined bidding zones". A biding zone is deemed to be a copper plate from power exchange point of view. All trades between nodes within a bidding zone are supposed to not be limited by the physical grid. If needed, the operational security of the electricity system at any node within a bidding zone must be maintained by other instruments than the day-ahead price. In Article 33 of European Commission guideline on allocation and congestion management, the criteria for reviewing bidding zone configurations is discussed. According to this article, if a review of bidding zone configuration is carried out, at least the following criteria shall be considered: a) network security b) overall market efficiency and c) stability and robustness of bidding zones.

However, a badly-designed bidding zone might cause market inefficiencies which we will discuss in this paragraph. A flow-based approach for allocation of scarce transmission capacity specified in TM takes into account the impacts of cross-border exchanges on network security constraints. Thus, this approach optimizes the market flows which maximize social welfare. This ensures efficient use of the part of the infrastructure capacity that is available for cross-zonal trade. However, the efficiency of using the inter-zonal infrastructure is not included in this approach and a badly-designed bidding zone configuration might affect the physical ability of the grid to transmit locally inside the zone. Trading inside zones may therefore happen alter cross-zonal trade by the loop flow effect. In an inefficient bidding zone configuration, these types of trade may implicitly be prioritised over cross-border trading flows and deteriorate the efficiency of CACM. Loop flows may cause discrimination between internal and cross-zonal exchange and have a negative impact on the overall social welfare and the distribution of benefit among market participants located at different geographical points in the network.

**The aspects that should be considered in the bidding zone configuration**

If bidding zones are sources of inefficiencies, why are bidding zones applied? According to CACM, "Bidding zones reflecting supply and demand distribution are a cornerstone of market-based electricity trading and are a prerequisite for reaching the full potential of capacity allocation method including the flow based method."

Whereas bidding zones have been a cornerstone of market-based electricity trading so far, it must still be explained why this is a prerequisite for efficient trading. Arguments are mentioned later in CACM in the discussion about the revisions of bidding zones. Among other things, the following aspects are mentioned:

a) Market liquidity
b) Market concentration and market power
c) Price signals for building infrastructure
d) Transaction and transition costs

Issue a), refers to the number of market participants active on the power exchange in day-ahead and intra-day markets, which is somehow a structural issue. If any given agent shall plan the operation in short-, medium- and long-term, it needs forecasts for prices to carry out the planning efficiently. If there is low liquidity, there will possibly be larger price-volatility and perceived randomness, which may lead to less efficient planning outcome. Smaller bidding zone reduces the size of the relevant market, and this can result in lower liquidity. However, also other factors such as structure, concentration and design of markets are important.

Reduced turnover in the market can also increase the risk of misuse of market-power, cf. b). This is probably the largest obstacle for considering a higher level of grid granularity. On the other hand, reduction of bidding zone size can result in a better evaluation of the network congestion in CACM process which can increase the possibilities to trade. Hence, it is important to assess the market power based on a trade-off between the size of the bidding zone and the level of the grid granularity. This gives a trade-off when considering the size of bidding zones.

A large and persistent price-difference between two areas is a signal that it would be profitable for the overall system to increase the transmission capacity. However, if the responsible TSO receive the congestion rent this can create a dis-incentive for actually carrying out those investments. The application of congestion rent revenues is limited by Regulation 714/2009 and regulated by NRAs. It is highly unlikely that a TSO would make a decision to postpone investments based on the fact that they would reduce the amount of congestion revenue obtained. Having two bidding zones with price differential is a correct price signal sent to producers to build generation infrastructures in the highest price bidding zone while with a single bidding zone no such price signal exists, cf. c).

A power producing company may have assets at many different locations, and there is a need for developing plans for operation, expansions/maintenance and other planning for each plant. If each plant is exposed to unique price structures and forecasts, the optimization task becomes more extensive. Hence, all kinds of administrative costs may increase when the number of market-segments increases, cf. d).

When defining an institutional structure aiming at maximizing efficiency, one also have to consider those kinds of aspects mentioned in a) – d). There are indeed important arguments for the view that zonal pricing is a prerequisite for efficient trading at least in a liberalized market.

On the other hand, a) – d) does not justify any possible zonal configuration. Instead, the needs for a fine granularity to find a close-to-optimal solution in a flow-based optimization must be balanced towards the needs for well-functioning local markets.

One possible alternative is to apply countertrade in large bidding zones, and possible optimization of this procedure to obtain an efficient allocation of the transmission capacity. However, it is important to take into account that the intention of the target model is different. The intention is that the efficiency of the planning of scarce transmission capacity should be enforced by the day-head and intra-day markets. In this way, one does not have to rely on the specifics and efficiencies in TSOs countertrade within large bidding zones. Also, more flexibility is likely to be available in practice by utilizing efficient mechanisms in day-ahead and intra-day markets. Bidding zones covering several large European countries are therefore not efficient. Thus, such bidding zones should not be considered as a part of the target model, even though there actually may be some large zones during the early stages of implementation.

Bidding zone configuration affects prices and therefore the incentives of price signals for operation and investment. If well-designed, the bidding zones can give yield efficient market signals for both operation and investment. If the bidding zone is highly dominated by renewable energy sources, prices will tend to be low or zero when these energy sources are operating at full capacity. This is a challenge for providing sufficient incentives for alternative flexible capacity, and also for remunerating investment in RES if current incentives are weakened. On the other hand, setting aside the pricing mechanism to producers e.g. by providing feed-in tariffs can lead to large additional costs for the system.

### 6.2.4 Timing for updating of bidding-zone borders

Two different processes are defined for considering bidding zone configuration.

- Every three years, ENTSO-E shall draft reports on current bidding zone configuration and its impact on market efficiency to ACER.
- In addition, a review of the existing bidding zone configuration may be launched by each of the following:
    - ACER, see (ACER, 2015)
    - Several regulatory authorities, pursuant to a recommendation from ACER
    - TSOs of a capacity calculation region, considering this region
    - Single TSOs, considering its control area
    - Member states, considering its capacity calculation region

The development process of the target model will take many years before a full implementation possibly exists. Moreover, even though the structural characteristics of the power system are changing rapidly, major changes occur over years and decades, not months. A full review every third year, combined with additional reviews launched when needed, is therefore likely be a sufficient institutional focus for this particular part of the target model.

### 6.2.5 Timing of Short Term markets

The timing of Short Term markets foreseen in the Target Model is one in which there is a Day-Ahead market producing results around 14:00 CET for the next day followed by a continuous intraday market in which trade can occur till at least one hour before real time. For the intraday it is allowed the co-existence of complementary regional intraday auctions as long as they don't hinder the functioning of the European continuous market.

While for the Day-Ahead market most national markets are already aligned with the European timings (a large number of countries makes already part of the Market Coupling operation), for the intraday, solutions are more diverse and the implementation of the European Intraday continuous market is still under way.

One of the questions to be analyzed is whether these timings of short term market should and could be adapted.

For the Day-Ahead, the evolution of European markets has been more or less similar amongst European countries. Indeed, the price for the following day was set in a single auction. The timing is such that it allows, on the one hand, making all subsequent TSO processes (communication of schedules, technical validation, etc.) and on the other hand gives enough timing to launch intraday markets for adjustments. The timing established for the market coupling operation is such that market players are able to submit bids and offers until 12:00 CET. This timing has allowed for market players to have reasonable forecasts on the operational conditions of its power plants, on demand forecasts of its consumers and, at the same time, has allowed TSOs to have on time a clear picture of what will be the following day operation look like and to validate it.

For these reasons, it doesn't appear to exist evidence that a change in day-ahead market timings would bring significant improvements to the market nor that market parties will strongly advocate it. Indeed, one must take into account that the day-ahead market is the cornerstone reference of electricity markets so in terms of prices and produced schedules. Moving the first short-term market closer to real time, while it could improve marginally the forecast accuracy of market players, could at the same time endanger a secure operation of the system so it should be rejected. On the other hand, moving this market away from real time would not bring high advantages for TSOs since they can cope with the existing timings while it would not be accepted by market parties.

For intraday markets there is a wider heterogeneity between national markets, so the discussion might be more open. Nevertheless, the Guideline CACM points out that the Gate Closure Time of Intraday markets should be at maximum, one hour before real time. This seems to be the compromise reached so that the gate closure time could be the closest possible to real time, allowing market players to adjust their schedules with the last available information, and, at the same time, giving enough time for TSOs to run system operation processes and to organize balancing markets.

In principle, by moving the intraday gate closure time closer to real time it will allow market participants to produce more accurate forecasts, namely for intermittent generation and for consumption and to, consequently, adjust their market schedules so that there is a better match with actual production and consumption. The degree to which there will be an improvement in market schedules compared to actual production and consumption can only be measured with actual implementation of the timing of markets.

Another relevant issue that needs to be evaluated with implementation of continuous intraday markets is liquidity. Theoretically, having a market always open, in opposition to a closed auction, will give more opportunities for market participants to trade whenever they need to. However, some have argued the need for closed auctions as a measure for liquidity concentration and for the creation of a relevant reference price.

If a continuous market doesn't gain enough levels of liquidity and market deepness it might happen that a renewable producer needing to adjust its market schedule will face few offers available in the market and will have difficulties to adjust the former. In this situation a "blind" auction might provide a more robust and reliable market price. However, in an efficient market, it would be expected that the continuous market would be able to address the needs of adjustments and that the correct amount of bids and offers would be produced.

In terms of capacity allocation, the target model for day-ahead market is an implicit allocation method. In this method the capacity is not, in practice, allocated to one specific player, but is rather used by all the system with the most efficient pricing. Market participants holding capacities acquired in long term auctions will still be able to nominate or receive the Use-it-or-Sell-it compensation. For this reason, the timing of the day-ahead market doesn't seem a critical issue in terms of capacity allocation.

For the intraday market, it is still not clear how the capacity will be priced in a continuous market. However, the most relevant issue is if any capacity still remains available for intraday trading, so that it can be used by market participants consistently and in a firm manner between all bidding zones. This is the challenge to address if regional intraday auctions are to be implemented, so that market participants in one region are not discriminated in the capacity allocation in comparison to market participants in other regions.

## 6.3 Very-short term

In the very short-term, the TM aims at integrating balancing markets in order to increasing economic efficiency, while maintaining operational security. As discussed in 4.4.2, the NC EB should increase economic efficiency in electricity balancing markets by:

i) Optimizing balancing actions performed by the TSOs;
ii) Fostering competition (in particular across borders) in providing balancing services;
iii) Providing incentives on BRPs to balance themselves or to help reducing the electricity system imbalance.

In order to achieve these objectives, the NC EB should, together with the NC CACM, facilitate liquid intraday markets with gate-closures close to real time, where BRPs can efficiently balance their portfolios. In this sense, the NC EB should stress the importance of a liquid intraday market as a cornerstone for a well-functioning balancing market. Intraday trading as close as possible to power delivery not only improves significantly the predictability of wind energy and other variable RES generation, but it also increases the flexibility of power system operation and reduces the amount of balancing energy required during real-time operation.

The NC EB should also provide for the integration of balancing markets across borders by harmonizing their designs and products in order to facilitate trade. Integrated cross-border markets allow for the aggregation of wind and other RES power across larger geographical areas and smooth variability. As these areas may belong to different TSOs, harmonization of gate closure times for trading balancing energy, and standardization of products as much as possible are fundamental to ensure liquidity and transparency in the market.

In order to guarantee competition and liquidity in balancing services markets the NC EB should facilitate non-discriminatory and transparent access on a voluntarily and remunerated basis to all potential balancing services' providers, including RES producers, storage technologies and demand. Therefore, when defining the final design of balancing markets, the TM should take into account the intrinsic characteristics of those providers.

Finally, the NC EB should require that TSOs provide the necessary information to BRPs so as to enable them to support the system's balance. In this respect information on volumes and prices of all balancing energy bids and all activated balancing energy bids in the previous imbalance settlement periods should be published shortly after real time and be available to all market parties.

As described in Section 4.4, the main common rules and principles established in the NC EB for the integration of national balancing markets refer to: i) the models for the integration of national balancing markets, (ii) procurement of balancing services, (iii) cross-zonal capacity for balancing services, and (iv) the imbalance settlement. In the following, it is discussed whether the NC EB addresses the challenges related with the above-mentioned aspects of cross-border electricity balancing.

### 6.3.1 Models for the integration of national balancing markets

For the integration of national balancing markets, the NC EB establishes a smooth transition starting from the creation regional models (i.e. integration of TSOs' control areas from at least two different Member States) for the application of the imbalance netting process and until the creation of EU-wide common merit order lists for all FRR and RR balancing energy products (see Table 4.1). This "slower" integration process is justified by the high complexity of integrating balancing markets and the lack of previous implementation experiences, and it should not lead, by itself, to suboptimal solutions.

On the other hand, if balancing arrangements are not sufficiently harmonized, regardless the adoption of a slower or a faster approach, the integration of national balancing markets will not succeed in increasing the efficiency of procurement of balancing services. Consequently, the harmonization of balancing arrangements (i.e. procurement and remuneration of balancing products, settlement periods, imbalance pricing, etc.) should be a primary objective in the NC EB development.

### 6.3.2 Procurement of balancing services

Regarding the rules and principles for the procurement of balancing services, ACER provides some recommendations related to aspects defined (or not defined) in the NC EB that may hinder the participation of RES and other potential BSPs, see also (Vandezande et al, 2010), and prevent the achievement of the full potential for economic savings when integrating balancing markets. The aspects that may hinder the participation of all potential BSPs and compromise competition and liquidity in balancing markets include:

- The NC EB does not describe principles and minimum requirements for the pre-qualification procedures to undertaken in order to become a BSP;
- While BSPs should provide all the necessary data and information needed by TSOs to evaluate the correct balancing service provision, this evaluation should be based on common principles that should be defined by the NC EB in order to ensure a level playing field for all BSPs;
- The possibility foreseen by the NC EB of procuring balancing capacity in longer timeframes and linking upward and downward products' procurement should ensure that it does not hinder the participation of flexible and renewable resources and BSPs;
- The NC EB is not clear when establishing that (pre-qualified) BSPs without a contract for balancing capacity provision should always be allowed to provide balancing energy bids to TSOs;
- Unshared bids discourage market participation and do not allow for transparent price formation that ensures a well-functioning balancing market. TSOs should not be entitled to define the amount of unshared bids, but should be obliged to put forward a methodology for calculating the amount of unshared bids. Furthermore, the transitional nature of these arrangements should be clearly highlighted in the NC EB.
- The NC EB does not respect the maximum lead-time for the balancing gate closure as established in the FG EB (i.e. one hour before real-time) and allows TSOs to establish the gate closure for automatically activated balancing energy bids before the gate closure time of the intraday market. Furthermore, the harmonization of balancing gate closure times is an essential to the establishment of cross-border balancing markets as envisaged by the FG EB and to ensure liquidity in balancing markets. In this respect, the EB NC states basic design

principles for gate closure definition but it does not include harmonization requirements[23]. Gate closures have to be as close as possible to real time[24].

### 6.3.3 Cross-zonal capacity for balancing services

Reservation of cross-zonal transmission capacity for the exchange or sharing of balancing capacity is allowed by the NC EB and must be consistent with the NC CACM[25]. Due to the limited availability of cross-zonal transmission capacity, in principle it should be used for the purpose where it yields the largest benefit. Therefore, cross-zonal transmission capacity should be reserved for balancing purposes only if the benefits that can be yielded in this timeframe are higher than the benefits that can be achieved in previous timeframes. As discussed in Section 4.4, the NC EB foresees three alternatives through which transmission capacity can be reserved for the exchange or sharing of balancing capacity: 1) the co-optimization process; 2) the market-based reservation process, and 3) the reservation based on an economic efficiency analysis.

According to ACER, reserving cross-zonal transmission capacity for the exchange of balancing capacity may lead to an increase in economic efficiency and social welfare. However, efficiency in cross-border markets for balancing capacity is not proved yet, utmost care should be taken to ensure that any reservation of cross-zonal capacity is efficient. In particular, there is a concern regarding the assessment of the value of cross-zonal transmission capacity for the exchange of balancing capacity (and, if activated, balancing energy) based on forecast methods. In this sense, the NC EB should elaborate more on the development and regulatory approval of methodologies for transmission capacity reservation for balancing purposes.

In this respect, it is important to emphasize that increasing economic efficiency is the main objective of the integration of national balancing markets. Therefore, cross-border transmission capacity should not be reserved with the only purpose of integrating those markets, but rather when the integration of those markets (including reservation of cross-border capacity) increase overall economic efficiency.

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[23] Article 20.3, EB NC
[24] EWEA suggest less than forty five minutes prior to real time delivery.
[25] Article 29 (3)

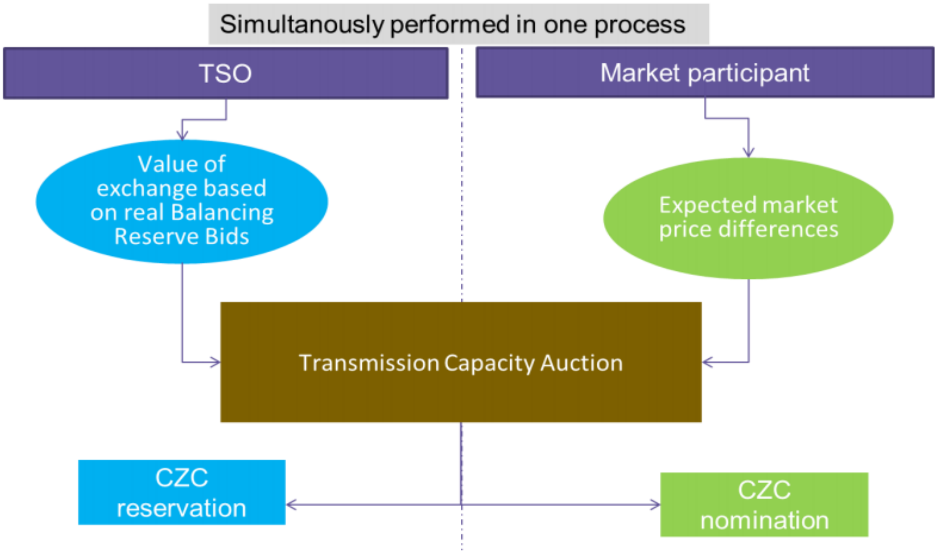


Figure 6-4: Reservation of cross-zonal capacity based on the Co-optimization process

### 6.3.4 Imbalance settlement & imbalance pricing

Regarding rules and principles for the imbalance settlement and imbalance pricing defined in the NC EB, some aspects should be further developed or improved in order to provide BRPs with sufficient incentives to balance themselves or to help reducing the system imbalance, see (Chaves-Avila et al, 2014). These aspects include:

- The harmonization of the imbalance settlement period. The NC EB is line with ACER FG guidelines, but the process will not be done until 2 years after entry into force of the NC EB and subject to a cost-benefit analysis. This reflects a long and complex process that does not enable the rate of deployment of RES to meet renewable energy and climate targets.
- The NC EB should ensure the publication of volumes and prices of all balancing energy bids and all activated balancing energy bids in the previous imbalance settlement periods shortly after real time. This, together with the application of single imbalance pricing based on the marginal price of activated balancing energy provides incentivize to BRPs to reduce the system imbalance and/or to restore its balance.
- In its current version, the NC EB allows for the use of single and dual imbalance pricing schemes based on either marginal and average prices of balancing energy. In general, the use of single imbalance price based on the marginal price of activated balancing energy provide the adequate incentives to BRPs, while it does not excessively penalized less flexible units, such as RES generators.

## 7 Conclusions

Achieving a well-functioning internal electricity market in the EU involves being able to supply load with a high enough level of security, at an affordable cost and prices, while achieving the sustainability of the system from a social, economic and environmental point of view. This is especially challenging since in order to comply with these objectives, the structure of generation and demand in the system will necessarily change. This will lead to a change, in turn, in the costs structure of most of the market agents.

The TM, developed by the European Commission in cooperation with the regulators and TSOs, represents a first attempt to adapt markets to the new system needs. Relevant stakeholders have managed to develop short-term energy markets that are gradually evolving towards a fully-integrated, efficient, pan-European one through the joint implicit auctioning of energy and transmission capacity in the day-ahead time frame. There are still aspects of short-term markets that need to be worked out in order for their functioning to be fully satisfactory, but the general design of these markets seems to be sound. Large progress has already been made in the implementation of day-ahead market coupling, which has allowed the coordinated dispatch of energy and interconnection capacity among systems in most of Western and Central Europe.

Aspects in short term markets that still need to be refined include:

- the definition of an appropriate level of granularity of the network model considered in the dispatch (currently, in the majority of Europe, each national system is considered a single node in the dispatch algorithm),
- the update of this network model;
- and the timing of energy markets, which relates, among other things, with the definition of the appropriate sequence of centralized auctions and continuous markets matching the needs of market agents.

Traditionally, long term transmission capacity products have been sold and subsequently traded to allow agents to manage the risk associated with the volatility in the price of access to the transmission grid. This, of course, is needed and is being already considered within the TM in FCA NCs. However, together with long term transmission capacity markets, other long term markets may need to develop. These potentially include “products” like long term firm generation capacity, clean energy and even balancing capabilities. These may be needed to ensure the appropriate amount of the corresponding products to be deployed. Otherwise, investment incentives may not be strong enough to trigger the installation of generation, demand and network assets required for the supply of these products.

A large number of national systems in Europe are already implementing capacity remuneration mechanisms, also called adequacy systems. However, the deployment of firm capacity in Europe should take place at a reasonable cost (including the system operational cost) This requires that solutions to contract capacity, if implemented, are applied in a coordinated way, thus allowing competition to take place among potential firm capacity providers all over Europe. Besides, remuneration schemes applied in long term capacity markets should not interfere with efficient signals in the short term.

As far as the supply of clean energy is concerned, this should be guaranteed in order to comply with environmental and RES objectives. The ability of currently existing energy markets to provide strong enough incentives to RES operators to install large enough amounts of this type of generation is dubious. Energy contracted in current markets does not need to be clean and the value of it at times when RES energy is available for its sale may not suffice to pay back investments in RES generation capacity. Thus, specific mechanisms may needed to contract the supply of clean energy. Long term supply schemes may be able to cover the increase in the costs of market agents associated with the provision of clean energy while allowing these agents to hedge against market price volatility. However, the supply of clean energy should in any case be arranged in a way that results in the lowest cost possible for the system in the short but also the long term. In this sense, signals resulting from these markets should not interfere with efficient short term, operation, signals.

Even the contracting of some balancing products in the long term may be considered, though the need for these remains to be seen.

Lastly, in the very short term, a perfect match between power supply and demand must be ensured at any time and it must take place in the most efficient way possible. Balancing markets are not new in Europe, but their functioning could be improved in several ways. Some of the changes to be made to balancing markets have to do with the need to achieve the integration of national ones. Others have to do with the need to integrate other resources than conventional providers such as energy consumers and RES generation both on the supply and on the demand side.

In order to achieve the integration of national balancing markets, issues to address include the harmonization of methods, or algorithms, used to trade balancing products and the harmonization of the features of balancing products themselves. This should increase the level of liquidity i and would avoid losses of efficiency from lacks of coordination among te several areas of the system. Besides that, access to interconnection capacity among systems in balancing markets should also be carefully thought in order to allow for cross border trade to take place while not impacting negatively the functioning of the other markets.

The participation of RES generation and demand in balancing markets should be achieved through abolition of unnecessary barriers (like minimum size ones, or prohibitions for them to aggregate into large entities like VPPs). Besides, authorities should promote the implementation of an efficient market scheme whereby prices earned for the provision of balancing services corresponds to their value, while payments reflect the responsibility of agents (BRPs) in balancing costs.

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