DAY-AHEAD MARKET

DETAILED MARKET DESIGN

JRC/PTT/2017/C.3/0017/OC

NL-Petten: Detailed Level Market Design of the Hellenic Forward, Day-Ahead and Intraday Markets and respective Market Codes and high-level IT

Task 2.1, version 3.0

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For the

Joint Research Centre
European Commission

November 17, 2017

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Revision History

Version	Date	Description: Forward Electricity Market
Version 0.5	08 July, 2017	ECCO First Internal Release
Version 1.0	13 July, 2017	ECCO First External Release
Version 1.5	18 August, 2017	ECCO Second Internal Release
Version 2.0	30 August, 2017	ECCO Second External Release
Version 2.5	06 November, 2017	ECCO Third Internal Release
Version 3.0	17 November, 2017	ECCO Third External Release

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Executive Summary

ECCO International ("ECCO") has been commissioned by the Joint Research Centre (JRC) of the European Commission to develop a Detailed Level Design, the Market Codes and the IT Functional Specifications for the Target Model-based energy market in Greece. This includes the Forward, Day-Ahead, and Intra-Day Markets for the Market Operator (LAGIE) and the Balancing Market for the Transmission System Operator, TSO (ADMIE). The proposed market design draws upon the High Level Market Design executed by ECCO in 2014.

This report is the **deliverable of Task 2.1 of this project**. The report analyzes the formation of the **Greek Day-Ahead Market and presents a Detailed Level Design of this market**, taking into consideration the procedures already established in the north-western European countries (Multi-Regional Coupling), the processes followed in the northern Italian borders and the special characteristics of the Greek electricity market.

According to the European Regulation 1222/2015 of 24 July 2015 establishing guidelines on capacity allocation and congestion management (hereafter referred to as CACM Regulation) it is obligatory to introduce a new Day-Ahead Market (DAM) design with specific rules in order to implement price coupling (implicit allocation of daily Physical Transmission Rights on the interconnections) in line with the provisions of the EU's Target Model. The current Greek market design does not support price coupling.

The restructuring of the Greek Day-Ahead Market is imposed under the CACM Regulation[1], which establishes guidelines on capacity allocation and congestion management and sets the requirements for the formation of a single internal day-ahead electricity market in Europe that will be cleared by a common price coupling market clearing algorithm (Article 38 of the CACM Regulation). As a Member State, Greece is obligated to fully comply with the European regulations and proceed with the restructuring of its Day-Ahead Market design, since such reform will lead to the maximization of the overall European social welfare through the efficient utilization of the scarce interconnection capacity and the effective allocation of the pan-European resources.

In the current (2017) Greek Day-Ahead Market design, daily Cross-Zonal Capacities are allocated through explicit day-ahead auctions in all interconnections. In compliance with the CACM Regulation, this should change to implicit auctions, implemented through the

[1] European Commission, Official Journal of the European Union, Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management. The Regulation is online available via the following link:

: http://eur-lex.europa.eu/legal-content/en/TXT/?uri=CELEX:32015R1222.

pan-European Day-Ahead Market coupling algorithm, EUPHEMIA[2]. The internal procedures and the standard corporate governance of the Multi-Regional Coupling (MRC) project shall be applied also in Greece. In this report we intend to further elaborate on the EUPHEMIA and the MRC since the Day-Ahead Market is solved by EUPHEMIA, developed on behalf of MRC and operated on daily basis by MRC.

All pre-coupling, coupling and post-coupling operations outlined in the CACM Regulation shall also be implemented by the Greek Market Operator and TSO.

Nevertheless, there will be a certain transitory period, in which only the Market Coupling (i.e. the implicit allocation of daily PTRs) with the Italian Borders shall be activated, whereas daily explicit auctions for the allocation of daily PTRs shall continue to be implemented for the Greek northern interconnections. During this period, there shall be a hydrid schema, under which Participants shall be able to submit import/export Orders in the Greek Day-Ahead Market only for the physical implementation of their traded quantities in the northern interconnections using explicitly allocated daily PTRs. Of course, Participants shall be able to submit import/export Orders in the Greek Day-Ahead Market for energy transactions with all neighboring countries using their allocated Long-Term (Yearly and Monthly) PTRs, according to the provisions of the Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA Regulation).

The timing of the Day-Ahead Market shall be in CET hours, namely the 24 hours starting from 01:00 EET of day D and ending at 01:00 of day D+1 shall be valid.

The participation in the Day-Ahead Market is mandatory only for the Producers who shall participate on a unit-basis. Participation is optional for RES Producers who can participate either on a unit-basis (per RES Unit) or on a portfolio-basis but only for their own RES Units; RES Aggregators may participate on portfolio basis per RES category and Load Representatives may participate on portfolio-basis for their whole portfolio. Nevertheless, it should be noted that the Participants shall be able to submit both Sell and Buy Orders for all entities they own/represent, namely:

1) Producers, RES Producers and RES Aggregators (representing physical assets) would normally submit Sell Orders in the Day-Ahead Market, but they will be able to submit also Buy Orders, in order to correct their Market Schedule stemming from the forward contracted energy quantities, and

2) Load Representatives would normally submit Buy Orders in the Day-Ahead Market, but they will be able to submit also Sell Orders, for the same reason as noted above

[2] Price Coupling of Regions, EUPHEMIA Public Description, December 2016. This description is online available via the following link:
https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf

in (1).

The selected possible Order types allowed to be submitted by the Participants in Greek Day-Ahead Market are the following.

a) Simple Orders (linear piecewise or step-wise curves), and

(b) Block Orders (including user-defined or MO-defined simple and profile Block Orders), as in most European markets[3],

The Greek Day-Ahead Market shall include two types of Orders (Simple and Block Orders), in order to increase the Producers' options to optimize their assets. By using only Simple Orders, it is difficult for Producers to attain feasible schedules for their Generating Units, due to the volatility of the Day-Ahead Market prices, the simplistic format of the Orders (for example lack of inter-temporal conditions, etc.), and the fact that EUPHEMIA (the software platform that clear the Day-Ahead Market) does not take explicitly into account the various unit operational constraints.

Participants are free to choose their own strategies and select the Orders that best optimize their assets. The Block Orders are more likely to result in feasible schedules for the Generating Units (if they are submitted appropriately by the Producers), and they can be submitted with an Order price that covers both the variable (operating) and fixed (start-up) cost of the unit.

It should be noted that Block Orders are currently used only in Day-Ahead Markets with portfolio-bidding participation. Nevertheless, their structure does not exclude the possibility to be also used in Day-Ahead Markets with unit-based participation, as is the case of the Greek market.

Moreover, the Producers are obligated (per Decision in the Law 4425/2016) to offer the remaining of the total production availability of the conventional Generating Units they represent in the Day-Ahead Market, in order to ensure the liquidity of the Day-Ahead Market and prevent physical withholding (semi-compulsory wholesale market). In this context, there is no possibility for Producers to "by-pass" the Day-Ahead Market and participate mainly (or solely) in the Intra-Day Market.

RES Producers and RES Aggregators (collectively called RES Operators) shall be able to submit all types of Orders, but:

[3] EPEX SPOT, EPEX SPOT Market Rules and Regulation - EPEX SPOT Operational Rules: https://www.epexspot.com/en/extras/download-center/documentation

Nordpool Spot, Elspot Market Regulations / Product Specifications:

http://www.nordpoolspot.com/TAS/Rulebook-for-the-Physical-Markets/Nordic-Baltic/

a) for Non-Dispatchable RES Portfolios (e.g. older wind plants, PV stations) and the specific features of the assets they own/represent (inherent variability and uncertainty) they may deem appropriate to only deploy Simple Orders,

b) for Dispatchable RES Portfolios (e.g. biomass and co-generation plants), Block Orders may be a good choice for the respective RES Operators.

Concerning the Load Representatives representing demand Entities, Simple and Block Buy Orders seem to be the most appropriate choices for the Greek Day-Ahead Market. Additionally, Load Representatives shall be able to submit any type of Sell Order (e.g. Simple Orders or Block Orders); upon clearing, these Sell Orders will constitute virtual energy production quantities, or equivalently demand reduction quantities. Participants are not confined by the MRC algorithm features for such options.

Concerning the Order feasibility in the Day-Ahead Market, the following feasibility checks shall be performed by the Trading Platform of the Market Operator on the Sell Orders at the Orders' submission phase prior to the market clearing:

a) **Generating Unit and RES Unit margin:** Even though the Sell Orders are economically binding, the Trading Platform of the Market Operator shall perform a validation check (as also implemented in the Italian market) to ensure that the offered quantities can be actually produced by the concerned Generating Units and RES Units. Therefore, at the submission process, the Trading Platform of the Market Operator shall validate per Generating Unit and RES Unit that the sum of Sell Orders submitted to the Day-Ahead Market, along with the validated Physical Delivery Nominations of Exchange Based Forward Market Contracts and Bilateral OTC Contracts, are exactly equal to the Available Capacity of the Generating Unit. Otherwise, curtailment rules on the DAM offers shall apply, or in case of Sell Block Orders they shall fully rejected.

b) **Import / export margins**: The Market Operator shall calculate the import/export margins, namely the maximum energy quantities to be offered for imports and exports in the non-coupled interconnections. More details about the calculation of the margins for imports and exports can be found in Section 6.3.6 of this report

Finally, it is important to note that in the current market structure of the Greek wholesale electricity market there is a dominant Market Participant that still has exclusive access to less expensive generation (taking aside the running of the current virtual power plant auctions) and the largest share in the retail sector. Theoretically, under these conditions, the dominant Participant may have a strong motive to engage in Bilateral OTC Contracts between its own production assets and its represented demand, thus draining the liquidity of the Day-Ahead Market and creating serious problems in the market price discovery process. In order to avoid such situation, ECCO has proposed in the HLMD Project of 2014 the implementation of a maximum percentage (threshold) of demand to be covered from Forward Contracts by the Participants bearing a large market share of end-consumption. In this way, (a) the liquidity of the Day-Ahead Market is secured, and (b) the attained Day-Ahead Market prices express the short-term marginal cost of the electricity to be produced / consumed, which is crucial in terms of market price discovery and market pricing efficiency. Extensive treatment of this maximum percentage threshold is provided in the LOT-3 Project.

The above-stated rule should be applied for a transitory period, in order to secure the smooth transition of the current market structure to a market where more Participants shall be vertically-integrated and/or participate with significant portfolios in the wholesale and retail markets in Greece. The regulatory-defined threshold can be increased (gradually relaxed) over time upon a regulatory decision, depending on the market conditions, until it is full cancelled.

It should be noted that this transitory rule is intended to cover only the anti-competitive behavior that can be possibly exercised by the former incumbent when engaging in forward contracting; respective rules have not been imposed for more complex cases of oligopolistic behavior of several generation companies. The latter cases are usually captured and penalized through market monitoring processes performed either by the Market Operator or by the Regulatory Authority. These entities monitor closely the strategic behavior of the Participants (one at a time or in groups performing concerted practices) for exercising market power and/or setting extraordinary high or low prices. In such cases, the Regulatory Authority has the power to impose strict sanctions on the concerned Participants, giving appropriate signals to all Participants to withdraw from any unlawful or anti-competitive practices.

1 Introduction

In the current (2017) Greek market structure, cross-border capacities in the Day-Ahead Market are allocated through explicit day-ahead auctions (i.e., auctions for the acquisition of daily PTRs in the day-ahead timeframe). The term "explicit auctions" means that cross-border capacity markets are independent from the energy markets of the countries/zones in question. It is up to the skill of traders to ensure that all profitable – and thus welfare-enhancing – arbitrage transactions are carried out successfully, which in turn requires that the equilibrium price for cross-border capacity – as it is determined in the day-ahead cross-border capacity auctions – is perfectly in line with the price difference between the neighboring zones' Day-Ahead (energy) Markets.

Obviously, when Day-Ahead Markets for capacity and for energy are cleared separately, it is very hard to bring about such an outcome. For one, it requires perfect foresight on the traders' part. When bidding for cross-border capacity, they should already be perfectly aware of the supply-demand conditions in the two zones and be able to predict with full accuracy the effect of cross-border trading on the energy price differences of the zones. Only then, they can assess the appropriate arbitrage transactions which contribute to the efficient use of the network infrastructure. **These assumptions are clearly unrealistic and as we expect, cross-border capacity is in general not used to its full effect, or sometimes is even used in the "wrong" direction. Empirical evidence in the Greek borders supports this observation.**

There is, however, a more efficient way of allocating cross-border capacity. When Day-Ahead Markets work as auctions (as they mostly do by deploying Power Exchanges or Power Pools), the clearing of the two neighboring Day-Ahead Markets can be performed jointly, automatically enabling supply and demand Orders to be available from the other zone as well, as long as cross-border transmission capacity is available. This mechanism is the so-called **Market Coupling mechanism**.

When two markets are coupled, all cross-border capacity between them is automatically allocated to the transactions with the highest arbitrage potential. Thus, the cross-border transmission capacity is allocated implicitly.

> **When two markets are coupled *the price of cross-border transmission capacity is equal to the energy price difference of the two zones.***

In a sense, cross-border trading by Participants, as it has been understood and practiced up to now, ceases to exist. Each Participant sells and buys energy in its home market, and inter-zonal arbitrage opportunities are exploited automatically by the Market Coupling mechanism. The money earned from this arbitrage is transferred to the TSOs (in agreed proportions), as the **Congestion Income** from operating the network.

By definition, implicit capacity allocation through Market Coupling calls for extensive harmonization across involved markets (in terms of gate closure times, operational procedures, types of products available, etc.). When these conditions are met, it is also relatively straightforward to extend the Market Coupling to any number of interconnected Bidding Zones.

Figure 1-1 illustrates the various elements of the Target Model with emphasis on the Day-Ahead Market.

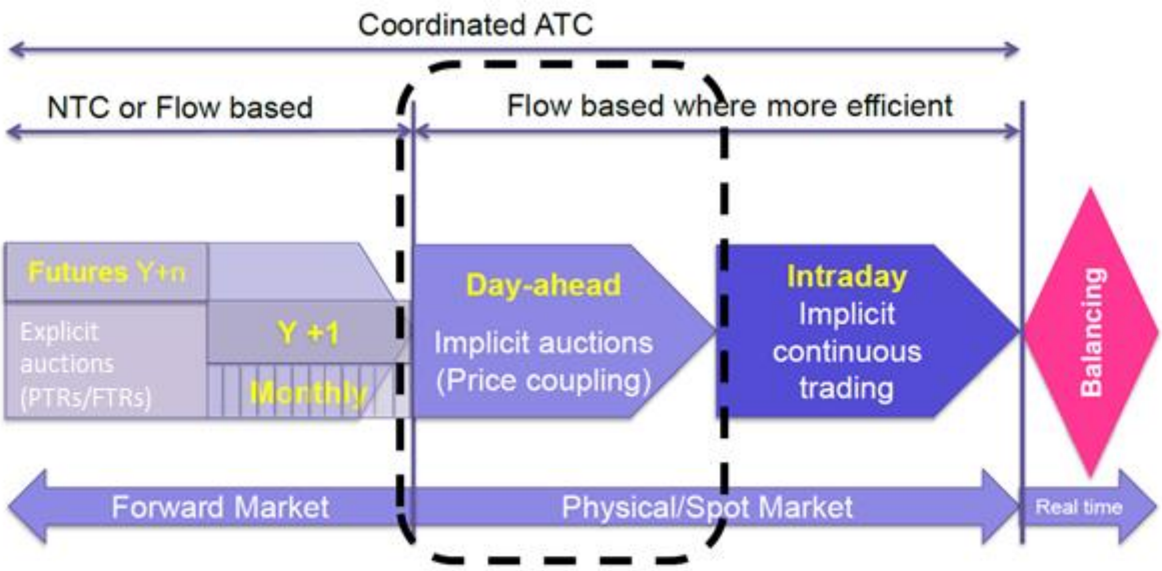

Figure 1-1: Day-Ahead Market in the context of the Target Model

The logic and expected benefits of coupling markets is reflected in the CACM Regulation, which represents the culmination of a long period of work involving the European Commission, ACER, TSOs, national regulators and stakeholders to develop a single energy market architecture for Europe.

The CACM Regulation outlines the architecture which needs to be in place to allow continuously traded Intra-Day Markets and implicit Day-Ahead Market auctions to take place, and provides rules for the operation of both these markets. **Specifically, for the Day-Ahead Market, the CACM Regulation prescribes implicit allocation of Cross Zonal Capacities through Market Coupling as the only acceptable method for the day-ahead Cross-Zonal Capacity allocation, except from the cases of coupling failure when explicit "shadow auctions" are performed as a fallback procedure. It also sets rules for defining and reviewing Bidding Zones and for calculating capacities in a coordinated manner.**

The implicit allocation of Cross-Zonal Capacities through Market Coupling at the day-ahead timeframe will result in the changing role of the trading process as follows:

1) **Daily Auctions for PTRs shall be replaced by implicit capacity allocation**, meaning that the accepted Orders across the European Bidding Zones shall define the usage of the Cross-Zonal Capacity of the interconnections, and the daily Physical Transmission Rights shall be acquired implicitly by the Participants through their accepted Orders for selling / buying energy.

2) Based on the above, **the Traders shall be excluded from participating in the coupled interconnection in the day-ahead timeframe**, and shall be able to trade in these interconnections only through long-term (yearly and monthly) PTRs.

3) Nevertheless, in the new market environment **the long-term PTRs nominations can be used by Traders to cover the forward contracted energy quantities** (corresponding to concluded transactions from the Exchange Based Forward Market and/or the Bilateral OTC Market).

In order the scope and rules, set in the CACM Regulation, to be implemented in a pan-European level and leverage the extensive experience acquired mainly by the north and CWE Day-Ahead Markets the initiative of Price Coupling of Regions[4] (PCR) was signed in June 2012, by seven partner Power Exchanges. These Power Exchanges are APX, Belpex, EPEXSpot, GME, Nordpool Spot, OMIE and OTE and cover the Day-Ahead Markets in Austria, Belgium, Czech, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxemburg, Netherlands, Norway, Poland, Portugal, Spain, Slovenia, Sweden and Great Britain. Specifically:

1) The common algorithm gives a fair and transparent determination of day-ahead electricity prices and a Net Position of a Bidding Zone across Europe, respecting the capacity of the Critical Network Elements (in the flow-based model). The algorithm is developed respecting the specific features of the various power markets across Europe and the critical electricity network constraints. It optimizes the overall welfare and increases transparency, efficiency and liquidity. This is crucial in order to achieve the overall EU target of a harmonized European electricity market.

   The new algorithmic solver used by the involved countries in the PCR initiative for the pan-European Day-Ahead Market coupling is called "Euphemia".

2) The PCR process is based on decentralized sharing of data, providing a robust and resilient operation.

3) The PCR Matcher and Broker service enables exchange of anonymized Orders and electricity network constraints among the Power Exchanges to calculate prices and Net Positions of all included Bidding Zones.

After several years of actual operation, the Day-Ahead Market design and operational

[4] Price Coupling of Regions. Accessed 01.07.17: https://www.epexspot.com/en/market-coupling/pcr

procedures rules have stabilized across Europe, in accordance with the CACM Regulation, and most markets in Europe are currently operating through harmonized rules / gate closures / product formats, and through a common Market Coupling algorithm (clearing the coupled Day-Ahead Markets) – Euphemia, as shown in Figure 1-2.

The CACM Regulation briefly describes the roles of the stakeholders in the Day-Ahead Market, including:

- pre-coupling operations,
- coupling operations, and
- post-coupling operations.

The details concerning these three distinct phases along with the detailed design of the Greek Day-Ahead Market are described in this report.

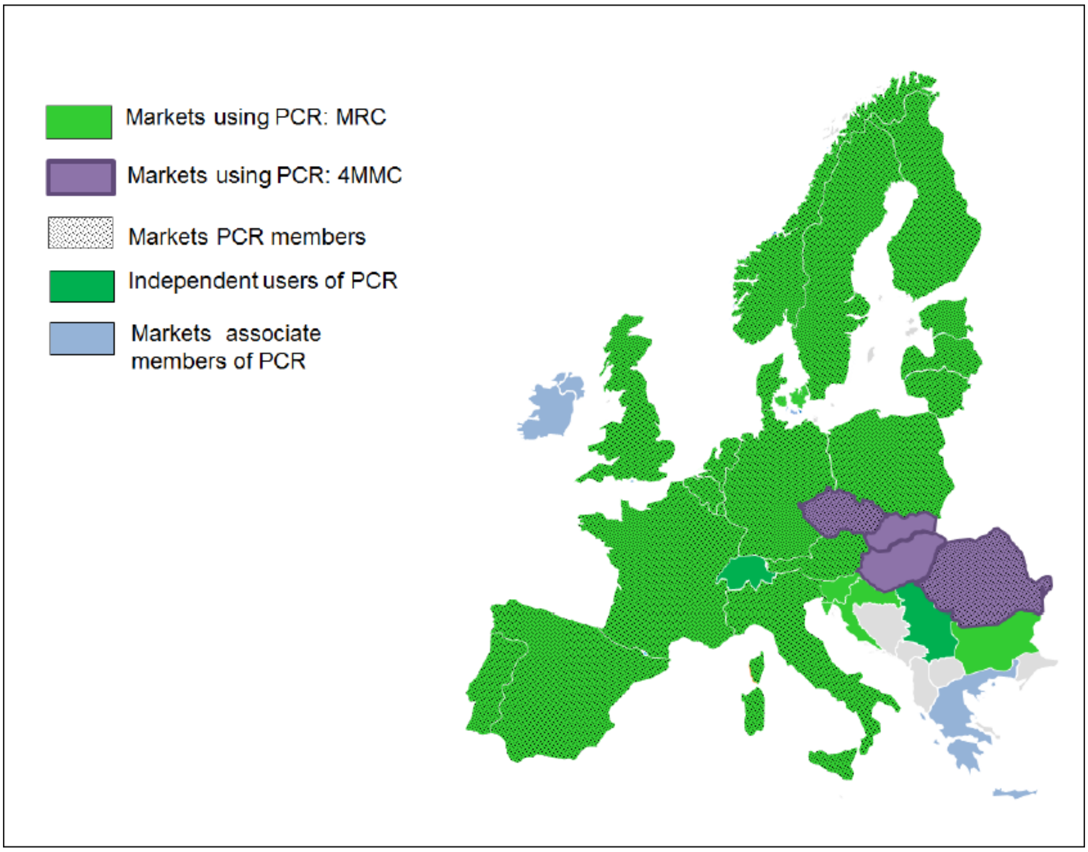

Figure 1-2: Price Coupling of Regions

We expect that the incorporation of the Greek Day-Ahead Market in the PCR project will have the following positive impacts on the Greek wholesale electricity market:

- Increase competition and reduce market concentration and market power issues, leading to more effective competition;
- Create a level playing field which fosters cross-border trade opportunities to large and smaller Participants alike;
- Optimally use existing transmission capacity and clearly signal the demand for new transmission capacity;
- Provide a clearer and more stable framework that can reduce barriers to entry into the market; and
- Remove arbitrary distortions and disincentives to trade caused by differential market rules with neighboring countries.

It should be noted that the target of this document is mainly not to describe the PCR internal processes, but to:

- analyze the operation of the Greek Day-Ahead Market (including pre-coupling, coupling and post-coupling procedures, gate closures),
- record all the stakeholders participating in the Day-Ahead Market in Greece along with the categorization of the Entities they represent, and the respective registries kept by the Market Operator, the Transmission System Operator and the RES and CHP Units Registry Operator,
- describe the tradable Products in the Day-Ahead Market, along with their respective Clearing rules,
- describe the interfaces of the Day-Ahead Market with the Forward and Intra-Day Markets, <u>**as well as with the Clearing House**</u>, and
- present the measures adopted to ensure the liquidity of the Day-Ahead Market, (and hence the price discovery process) namely a maximum percentage of Forward Contracts to cover a demand portfolio can be imposed onto Load Representatives with significant retail market shares.

The structure of this report is as follows:

Chapter 2 prescribes to the roles of the stakeholders, as stated in the CACM Regulation.

Chapter 3 presents the Participants of the Day-Ahead Market, the Entities represented, the Registries kept by the Market Operator, the Transmission System Operator and the RES and CHP Units Registry Operator, the Energy Trading System operated by the Market Operator and used for the Day-Ahead Market processes and the respective participation requirements, rules and fees applicable in the Greek wholesale electricity market.

Chapter 4 elaborates on the interfaces of the Day-Ahead Market with the Exchange Based Forward Market and the Bilateral OTC Market. More specifically, it describes the process for achieving the physical delivery of the contracts concluded in the Forward Market.

Chapter 5 presents the format and type of Orders that shall be tradable in the Greek Day-Ahead Market, taking into account all the types of Orders applicable in the European electricity markets.

Chapter 6 introduces the timeline and basic processes of the Day-Ahead Market in Greece, including the information concerning the Order Limits imposed in the framework of the Greek Day-Ahead market, the information transfer between the respective stakeholders during the trading and pre-coupling operations, the market clearing and coupling operations and the post-coupling operations.

Chapter 7 presents the interface of the Day-Ahead Market with the Intra-Day Market, namely the information that shall be transferred from the Day-Ahead Market to the Intra-Day Market.

Chapter 8 presents the Day-Ahead Market Settlement procedure followed by the Clearing House for the calculation of the Debits and Credits and for the application of non-compliance charges in case of a) unlawful submission of Sell Orders with respect to the Available Capacity and b) non-compliance on behalf of the Load Representatives with the criterion regarding the maximum percentage of the forward contracted quantities.

Chapter 9 presents the fallback procedures that shall be followed in case a Partial or Full Decoupling is experienced during the Market Coupling process.

Annex A describes the basic features of the ATC-based and flow-based congestion management models, along with the calculation of the respective parameters (ATCs and flow-based parameters, respectively).

Annex B presents the basic information concerning the Day-Ahead Market matching process, based on Euphemia public description (version December 2016).

Finally, *Annex C* presents the categorization of RES and DR resources, based on the legal framework in Greece (Law 4414/2016).

It should be noted that the terms used with capital letters in this report shall for all purposes of this report have the meanings specified in the separate document entitled "Definitions". Also, all timings included in this report are in Eastern European Time (EET), unless explicitly stated differently.

2 Roles of Stakeholders in the Market Coupling Process

In this Chapter, we describe the roles of the main European stakeholders, along with their main responsibilities during the pre-coupling, coupling and post-coupling operations in the Day-Ahead Market, as described in the CACM Regulation. In the IT functional specifications document we present the interfaces between the Market Operator and the PCR Organization for the DAM operations. However, note, internal documents and/or IT specifications of the PCR, are not publicly available. Hence details about their systems/platforms are not presented. Further, note, the PCR Organization for the DAM Operation is currently transferred to the All NEMOS MCO Plan + the relevant All NEMOS Day-Ahead Operational Agreement (ANDAOA).

Figures 2-1 to 2-4 below illustrate the basic information flow between the stakeholders, while Table 2-1 includes a brief description of each process presented in these Figures. It should be noted that the last column of this Table corresponds to the respective Article of the CACM Regulation for easy tracking purposes. In the context of these Figures, the roles of the main stakeholders are the following:

- ❖ **Transmission System Operators (TSOs)**

The TSOs must define the Bidding Zones within their responsibility area; it should be noted that:

a) in the ATC-based model, within the territory of each Bidding Zone no intra-zonal congestion is considered at the Day-Ahead and Intra-Day Markets, whereas the inter-zonal corridor constraints among the Bidding Zones is respected.

b) in the flow-based model, even intra-zonal Critical Network Elements are considered, and their respective flow based parameters (their estimated zonal PTDFs and their RAMs) are inserted in the constraint set of the Day-Ahead Market problem formulation.

In addition, the TSOs have a significant role mainly in the pre-coupling and post-coupling operations.

In the **pre-coupling operations**:

a) A designated TSO or designated TSOs should receive the Individual Grid Models of each Control Area by the respective TSOs, and combine them into a single Common Grid Model (CGM)[5]. The Individual Grid Models include

[5] A detailed technical analysis of the European Merging Function can be found in the following link:

information from generation and load units. The TSOs submit the CGM to the Coordinated Capacity Calculator (CCC).

b) TSOs shall provide the Coordinated Capacity Calculators and all other TSOs in the Capacity Calculation Region the following items: operational security limits, Generation Shift Keys, remedial actions, reliability margins, allocation constraints and previously allocated Cross-Zonal Capacity, as per paragraph 1 of Article 29 of the CACM Regulation.

c) TSOs establish and perform capacity calculation in accordance with Articles 14 to 30 of CACM Regulation, as per paragraph 2(c) of Article 8 of the CACM Regulation.

d) Each TSO shall validate and have the right to correct Cross-Zonal Capacity relevant to the TSO's Bidding Zone borders or Critical Network Elements (CNE) provided by the Coordinated Capacity Calculators. Each TSO may reduce Cross-Zonal Capacity during the validation of Cross Zonal Capacity for reasons of operational security, as per paragraph 3 of Article 26 of the CACM Regulation.

e) Each TSO shall send its capacity validation and allocation constraints to the relevant Coordinated Capacity Calculators and to the other TSOs of the Capacity Calculation Regions.

f) TSOs shall receive the nominations of long-term PTRs submitted by the Participants, for the purposes of computing and matching the Cross-Zonal Capacities.

In the coupling operations TSOs perform the following activities:

- receive the preliminary results from the NEMO (Scheduled Exchanges or / and Net positions). TSOs check the preliminary results and send confirmation of the preliminary results to the local NEMO.

In the **post-coupling operations**, TSOs perform the following activities:

a) TSOs receive from the Scheduled Exchange Calculator information on the Scheduled Exchanges, and send to the neighboring TSOs the full-set of cross-border Scheduled Exchanges (cross-border energy quantities cleared in the Day-Ahead Market, along with the already matched nominations of long-term schedules) for matching purposes, in the notification and congestion income process of the post-coupling phase.

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https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/cacm/cgmm/European_Merging_Function_Requirements_Specification.pdf

b) TSOs receive the Market Coupling results from the Market Coupling Operator (MCO) and verify the single Market Coupling results.

c) In accordance with Article 73 of CACM Regulation, TSOs shall distribute the Congestion Income according to a specific methodology jointly proposed and developed by all TSOs and accepted by ACER[6].

❖ **Coordinated Capacity Calculator (CCC)**

The CCC is an entity that undertakes the task of calculating Cross-Zonal Capacity within a Capacity Calculation Region (CCR)[7]. The CCC is a role of an entity assigned by the relevant TSOs, and is active in the **pre-coupling operations** regardless of the capacity calculation methodology. Under normal conditions:

➢ If the flow-based approach is implemented, then the CCC receives the CGM (with the European Merging Function requirements), and computes (actually estimates) the zonal Power Transfer Distribution Factors (PTDFs) and the Remaining Available Margins (RAMs) that should be inserted in the Market Coupling algorithm using the Generation Shift Keys (GSKs) and the Critical Network Elements (CNEs) from TSOs. (Article 29, CACM). **The CCC submits this information to the relevant NEMOs for publication purposes, according to paragraph 1 of Article 46 of the CACM, and the NEMOs submit this information to the Market Coupling Operator (MCO). More details about the calculation of the flow-based parameters can be found in Annex A.**

➢ If the ATC-based approach is implemented, then the CCC, using the CGM, the European Merging Function requirements, the Generation Shift Keys and contingencies, calculates the maximum power exchange on Bidding Zone borders and the Cross-Zonal Capacity values. **These cross-border capacity constraints are respected in the Market Coupling algorithm, while intra-zonal constraints are neglected.**

After the calculation, the CCC submits the Cross-Zonal Capacity to the TSOs for validation purposes. Then the TSOs perform the activities that were described in the pre-coupling operations, point (c) of this section.

After the validation process and according to Article 46 (1) of the CACM Regulation the

6 All TSOs' Proposal for a Congestion Income Distribution (CID) methodology in accordance with Article 73 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management.

7 According to All TSOs' proposal for Capacity Calculation Regions (CCRs) in accordance with Article 15(1) of the Commission Regulation (EU) 2015/1222, Greece is involved in two CCRs, namely in CCR 5 including the Greece – Italy borders and in CCR 10 including the Greece – Bulgaria borders.

CCC shall ensure that Cross-Zonal Capacity and allocation constraints shall be provided to the relevant NEMOs on time.

- ❖ **Participants**

The Participants are active in the **pre-coupling operations**. They submit their Orders to the Nominated Electricity Market Operators (NEMOs), through a Trading Platform, according to the special bidding rules in their Bidding Zone(s).

In the **post-coupling operations**, the Participants receive the market results (successfully matched/cleared Orders) from the NEMOs.

- ❖ **Nominated Electricity Market Operators (NEMOs)**

The NEMOs shall be active in the **pre-coupling operations**. They shall collect the Orders submitted by the Participants through a Trading Platform, and they shall deliver anonymously these Orders to the Market Coupling Operator (MCO). In the ATC-based model, they may also receive the ATCs from the TSOs.

In the **post-coupling operations**, NEMOs shall perform the following activities:

a) They shall receive the Market Coupling results (for final verification) from the MCO.

b) They shall send the final results to the Participants active in their Bidding Zones.

c) They shall publish for relevant Participants at least the status of execution of Orders.

d) They may act as Central Counter Parties for clearing and settlement purposes, in case this role is not assigned to a third party.

NEMOs provide the interface for the submission of the Orders in the Day-Ahead and Intra-Day Markets.

In the PCR internal organization, there is a possibility for NEMOs to become either "PCR full members", namely to have full access to all PCR data and properties (Euphemia solver, PMB, testing environment, checking of results, etc.) and perform the tasks of the Operator and the Coordinator/Backup Coordinator or a "PCR serviced member", namely to be serviced for the usage of the PCR Market Coupling assets by a "PCR full member". In addition, under the "All NEMO proposal for the MCO Plan" it is specified that NEMOs can participate in Market Coupling by granting a license for using MCO function assets ("licensee" option) under a fee. A licensee can perform the tasks of the Operator and the Coordinator/Backup Coordinator.

- ❖ **Market Coupling Operator (MCO)**

The MCO is a NEMO, and is active in the **coupling operations**. The MCO:

a) receives the anonymous Orders from a dedicated IT platform (cloud), where the NEMOs (PXs) have transferred the Orders after they have been submitted by the Participants to the Local Trading Platforms of each NEMO,

b) performs the matching of the submitted Orders for all Bidding Zones, taking into account the allocation Constraints and the Cross Zonal Capacity, and thereby implicitly allocating capacity for the day-ahead timeframe, and

c) sends the Market Coupling results to all NEMOs (PXs), Coordinated Capacity Calculators and all TSOs.

It should be noted that the MCO is governed by the provisions set out in the Market Coupling Operation Functions (MCO Plan) that has been proposed by all NEMOs and been approved by all National Regulatory Authorities (see RAE Decision 533/2017) pursuant to article 7(2) of the CACM Regulation. This MCO Plan details the governance and cooperation rules among the NEMOs and outlines the relationship with third parties. The MCO Plan also defines the transition from the current day-ahead and intra-day Market Coupling initiatives to the Single Day-Ahead and Intra-Day Market Coupling that forms the cornerstone of the European Target Model for Electricity. The governance structure proposed in this MCO Plan includes the following contracts: one “All NEMO Cooperation Agreement” (the “ANCA”), two "NEMO Operational Agreements” (one for the day-ahead and one for the intra-day), plus a set of contracts between NEMOs and third party service providers needed for the delivery of the MCO Functions. The MCO Functions consist of developing and maintaining the algorithms, systems and procedures for the Single Day-Ahead and Intra-Day Market Coupling process, processing input data on Cross-Zonal Capacity and Allocation Constraints provided by the Coordinated Capacity Calculators, operating the price coupling and continuous trading algorithms and validating and sending single day-ahead and intraday coupling results to NEMOs.

❖ **Central Counter Party (CCP)**

The CCP is active in both pre-coupling and post-coupling operations. In general, the CCP provides financial services to the Participants, NEMOs and to the TSOs.

In the **pre-coupling operations**, the CCP performs the risk management process (validity check) for the Orders submitted by the Participants within the frame of the Day-Ahead Market.

In the **post-coupling operations**, the CCP:

a) Performs the clearing (including netting processes), settlement, invoicing and liquidation (money transfer) of the trades.

b) Receives the cross-border Scheduled Exchanges from the Scheduled Exchange Calculator (SEC).

c) Interacts with the Shipping Agent for the exchange of energy. The Shipping Agent can be either a separate entity, or the CCP itself (as for example ECC in France and Germany), or the TSO (as for example TERNA in Italy).

d) Provides the Congestion Income to the TSOs. In accordance with Article 68 of CACM Regulation, CCPs or Shipping Agents shall collect the Congestion Income arising from the Single Day-Ahead/Intra-Day Market Coupling and shall ensure that collected Congestion Incomes are transferred to the TSOs.

❖ **Scheduled Exchange Calculator (SEC)[8]**

Typically, according to the CACM Regulation the SEC is a role of a TSO, and is active mainly in the **post-coupling operations**. The Scheduled Exchange Calculator shall be established at least at the Capacity Calculation Region level (as defined by Article 2(3) of the Regulation 2015/1222) only by those TSOs which intend to calculate Scheduled Exchanges, as per Article 43 of the CACM Regulation. The establishment and the existence of this entity is provisioned by the CACM Regulation, but it has no obligatory character. **It is noted that according to Article 2(32) of the CACM Regulation a "Scheduled Exchange" means an electricity transfer scheduled between geographic areas, for each Market Time Unit and in a given direction.**

Hence there are two categories defined depending on whether the respective TSO intends or not to use the results of the Single Day-Ahead Market Coupling algorithm (e.g. the allocation flows). Those TSOs which intend to calculate Scheduled Exchanges shall use as input into the Scheduled Exchange calculation the allocated capacities in the form of allocated power flows received from the relevant NEMOs as a result of the Market Coupling results, as stipulated under Article 3 of the Day-Ahead Scheduled Exchanges Calculation Methodology[9]. While TSOs which do not intend to calculate Scheduled Exchanges using the Day-Ahead Scheduled Exchanges Calculation Methodology shall validate and use the Scheduled Exchanges resulting from the Single Day-Ahead Market Coupling and consequently they do not apply the Day-Ahead Scheduled Exchange Calculation Methodology. (All TSOs, according to Article 43 of the CACM Regulation, are expected to develop and submit such a methodology for further discussion.) The Scheduled Exchange Calculator role shall evolve along with the Day-Ahead Market coupling operations moving towards market integration at pan-European level. The Day-Ahead Scheduled Exchanges Calculation shall be initiated upon receipt of the items included within the list of requirements from relevant NEMOs.

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8 The Scheduled Exchange Calculator may under conditions be incorporated in the PCR, based on current discussions in the NEMO Committee.

9 All TSOs' proposal for a Methodology for Calculating Scheduled Exchanges resulting from single day-ahead coupling in accordance with Article 43 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

The Relevant NEMOs, as an output of the Market Coupling algorithm, should provide the information listed (and presented below) in Article 3 of the Day-Ahead Scheduled Exchanges Calculation Methodology to the Scheduled Exchange Calculator and all TSOs by 13:00 market time day-ahead but not later than 15.30 market time day-ahead. The Scheduled Exchange Calculator shall notify the results of the Day-Ahead Scheduled Exchanges Calculation to relevant NEMOs, Central Counter Parties, Shipping Agents and TSOs within 15 minutes after delivery of the information listed in Article 3 by the relevant NEMOs. The results of the Scheduled Exchange Calculator shall be (for each Market Time Unit):

- Bilateral Scheduled Exchanges per DC network element, per Scheduling Area border, per Bidding Zone border and between NEMO Trading Hubs;
- Multilateral Scheduled Exchanges per Scheduling Area, per Bidding Zone and per NEMO Trading Hub[10].

The Relevant NEMOs shall provide the following information, resulting from the Single Day-Ahead Market Coupling algorithm to the Scheduled Exchange Calculator and all TSOs, for each Market Time Unit, in order to perform the Day-Ahead Scheduled Exchanges Calculation. (Note, the actual time interval is not specified consistent with Article 40(2) of the CACM Regulation):

- Rounded and unrounded Net Position per Scheduling Area;
- Rounded and unrounded Net Position per Bidding Zone;
- Rounded and unrounded Net Position per NEMO Trading Hub;
- A single clearing price for each Bidding Zone and Market Time Unit in €/MWh;
- Allocated capacities, in the form of allocated flows into and out of individual relevant DC network elements (difference in flows in/out reflecting losses where applicable);
- Allocated capacities, in the form of allocated flows on relevant Bidding Zone borders (flows in/out reflecting losses where applicable).

The receipt of this information is essential in order for the Scheduled Exchange Calculator to perform the calculation of Scheduled Exchanges.

[10] Multiple NEMO trading hubs are not applicable in the Greek energy market since there is only one NEMO..

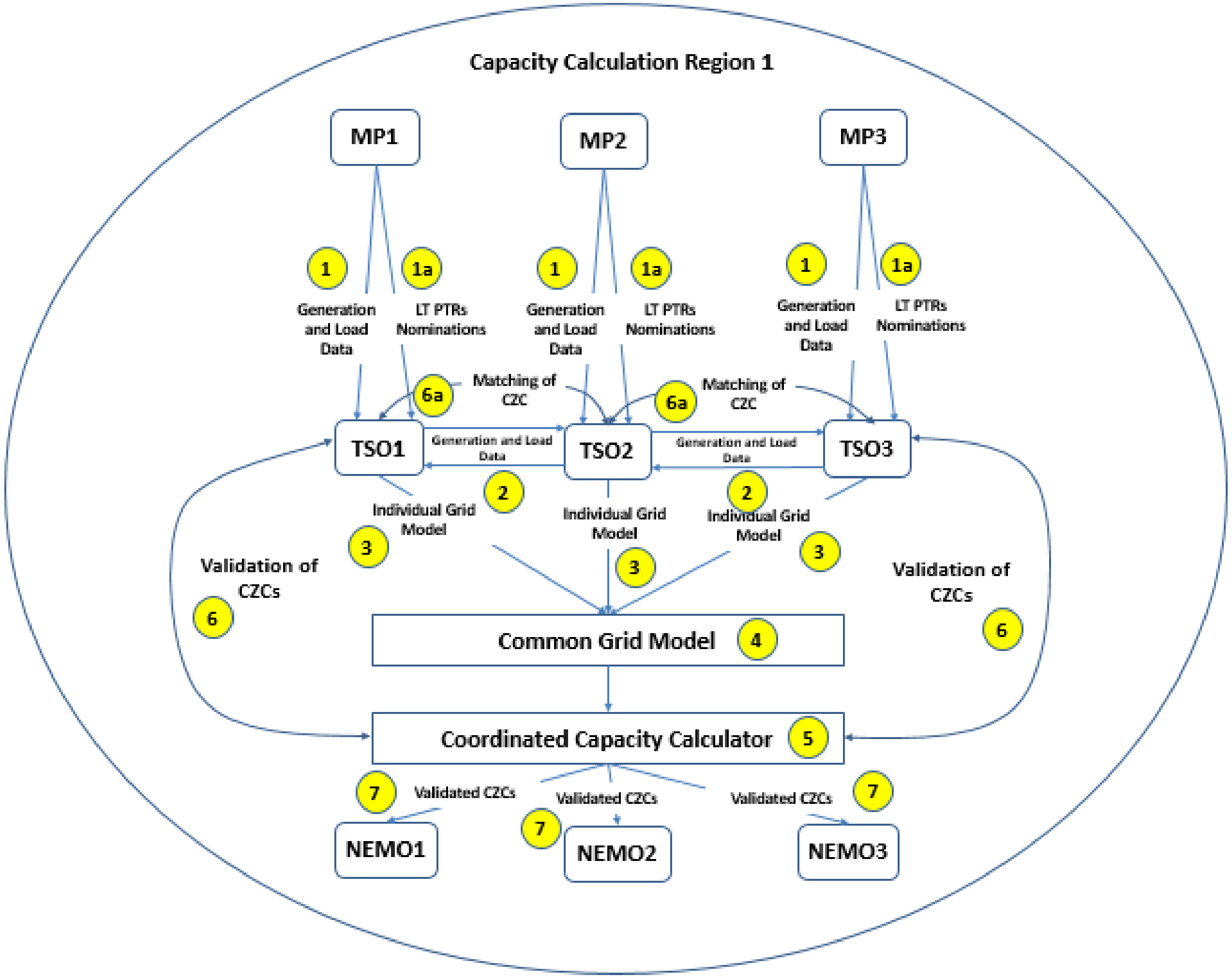

Figure 2-1: Pre-Coupling Operations concerning the Regional Capacity Calculation

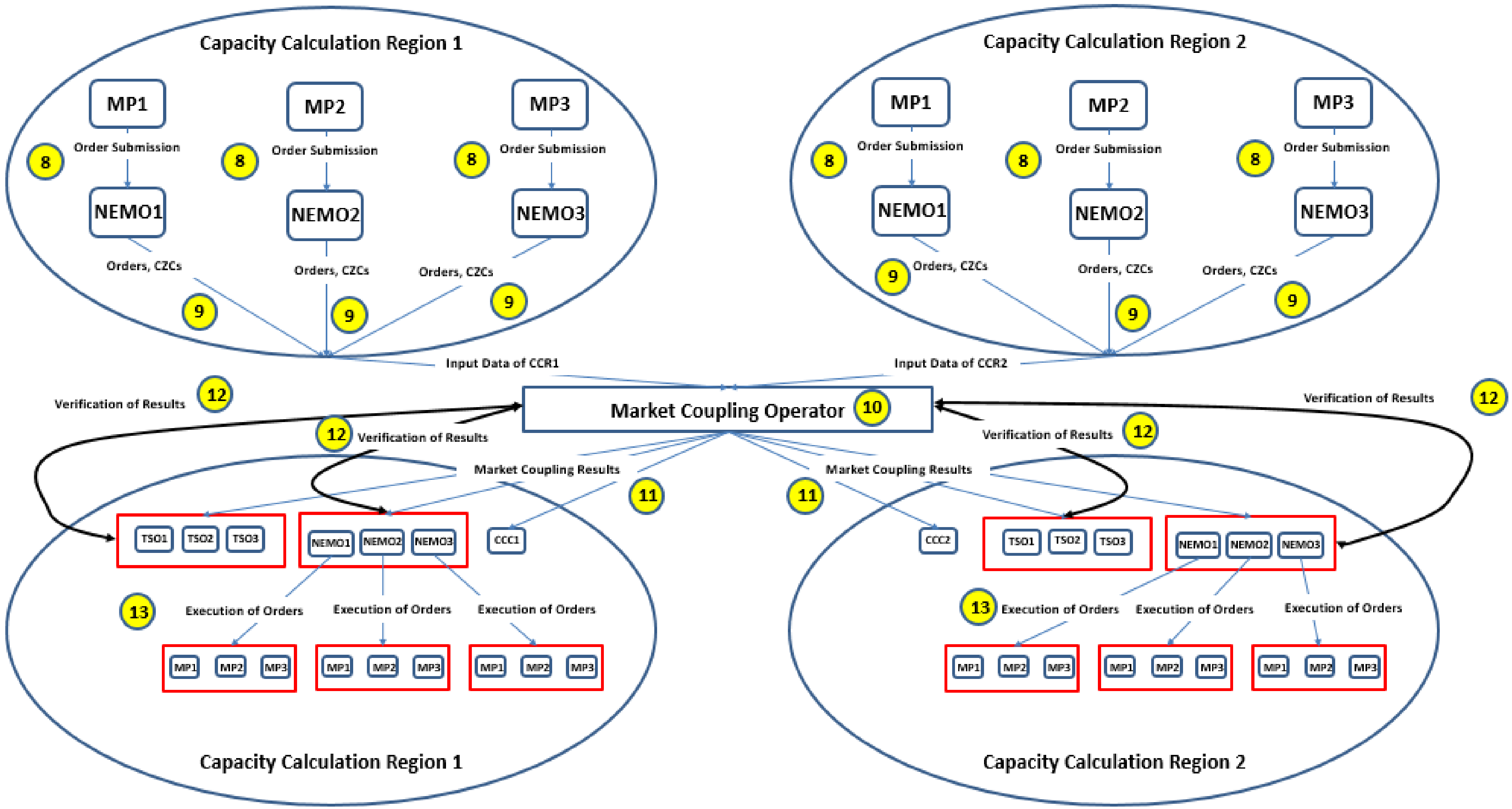

Figure 2-2: Pre-Coupling, Coupling and Post-Coupling Operations concerning the derivation of the Market Coupling Results

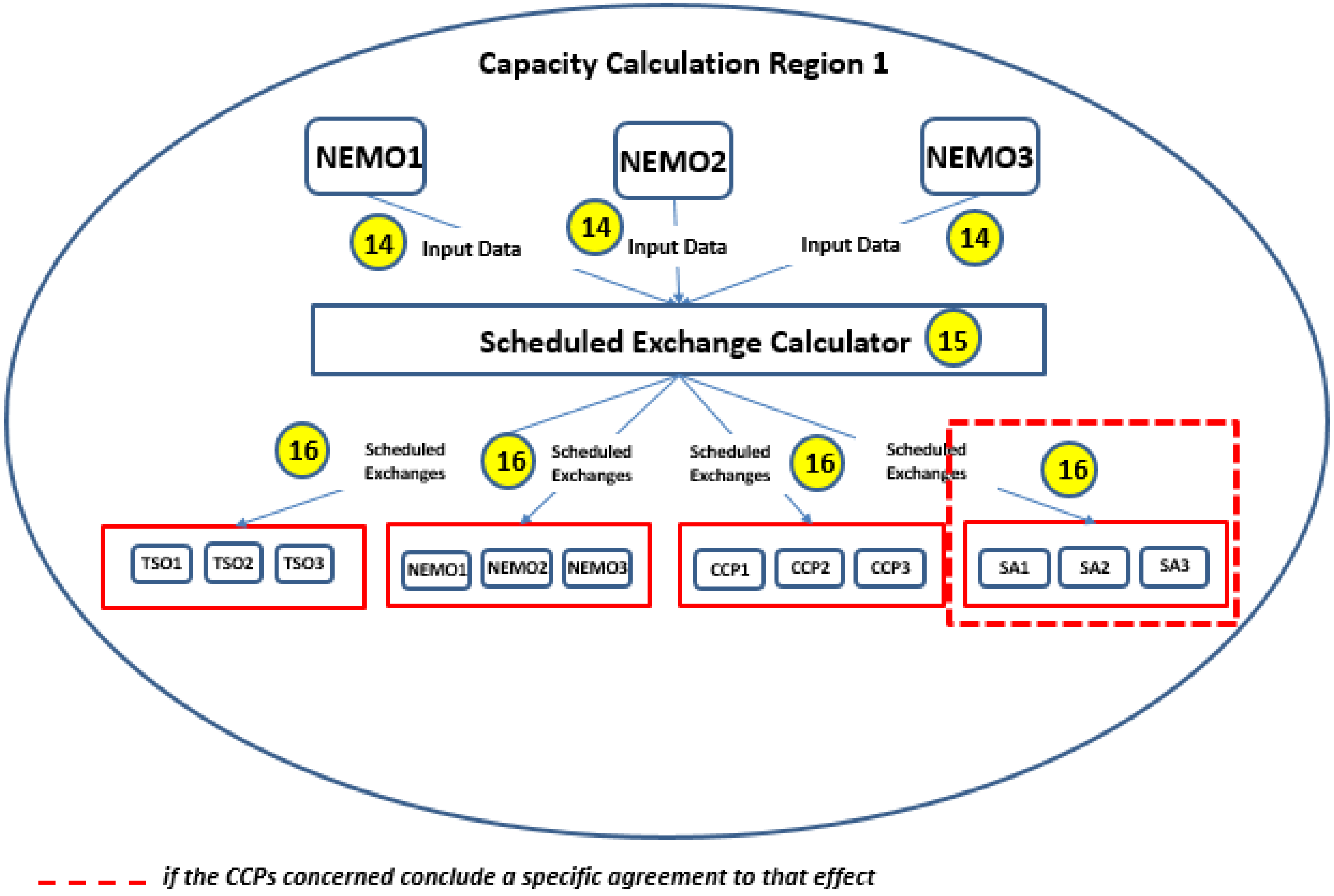

Figure 2-3: Post-Coupling Operations concerning the calculation of the Scheduled Exchanges

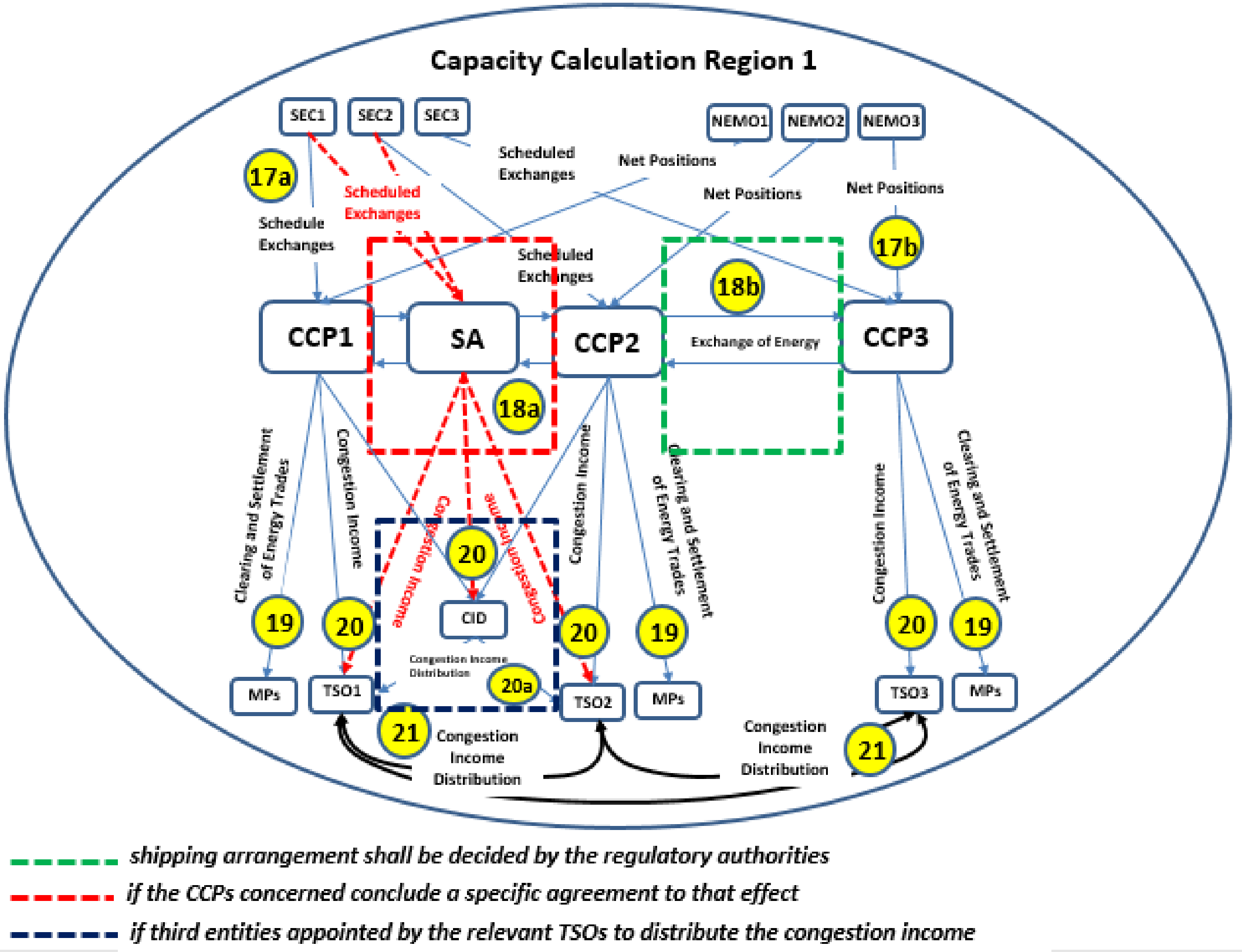

Figure 2-4: Post-Coupling Operations concerning the Clearing and Settlement of Trades

No	Process	From	To	Description	CACM Regulation
1	Generation and Load Data Provision	Participants	TSOs	Each generator or load unit shall provide the data specified in the generation and load data provision methodology to the TSO responsible for the respective control area.	Article 28 (1)
1a	LT PTR nominations	Participants	TSOs	Each Participant nominates the LT PTRs to the respective TSO.	
2	Share of Generation and Load Data between TSOs	TSO	TSO	Each TSO shall use and share with other TSOs the information to be provided by generation units and loads to TSOs.	Article 16 (5)
3	Creation of Individual Grid Model	TSO	-	Each TSO in the Bidding Zone shall provide an Individual Grid Model for its Control Area.	Article 19 (1)
4	Creation of the Common Grid Model	TSO responsible for merging the Individual Grid Models	-	Each TSO shall deliver to the TSOs responsible for merging the Individual Grid Models into a Common Grid Model the most reliable set of estimations practicable for each Individual Grid Model.	Article 28 (4)
5	Regional Capacity Calculation Process	Coordinated Capacity Calculator	-	Each Coordinated Capacity Calculator shall perform an operational security analysis applying operational security limits by using the Common Grid Model created.	Article 29 (2)
6	Validation of Cross Zonal Capacities	Coordinated Capacity Calculator	TSOs	Each TSO shall validate the results of the regional capacity calculation for its Bidding Zone borders or Critical Network Elements.	Article 30 (1)

6a	Matching of CZC	TSO	TSO	Matching of Cross-Zonal Capacity in both directions	
7	Provision of Validated Cross Zonal Capacities	Coordinated Capacity Calculator	NEMOs	Each Coordinated Capacity Calculator shall ensure that Cross-Zonal Capacity and Allocation Constraints shall be provided to relevant NEMOs.	Article 46 (1)
8	Order Submission	Participants	NEMOs	Participants shall submit all Orders to the relevant NEMOs before day-ahead market gate closure time.	Article 47 (3)
9	Sending of Input Data for Market Coupling	NEMOs	MCO	Each NEMO shall submit the Orders received to the MCO.	Article 47 (4)
10	Market Coupling	MCO	-	The MCO performs the process of the Market Coupling by using the price coupling algorithm.	Article 37
11	Sending of Market Coupling Results	MCO	TSOs, NEMOs, CCCs	The MCC shall deliver the Market Coupling results to all TSOs, all CCCs and all NEMOs.	Article 48 (1)
12	Validation of Market Coupling Results	TSOs	-	Each TSO shall verify that the Market Coupling results of the price coupling algorithm have been calculated in accordance with the Allocation Constraints and validated Cross-Zonal Capacity.	Article 48 (2)
		NEMOs	-	Each NEMO shall verify that the Market Coupling results of the price coupling algorithm have been calculated in accordance with the Orders.	Article 48 (3)
13	Sending of Orders'	NEMOs	Participants	Each NEMO shall inform Participants on the execution status of their Orders.	Article 48 (4)

	Execution				
14	Sending of Input Data for the Calculation of the Scheduled Exchanges	NEMOs	SEC	Each NEMO shall provide the relevant SEC with the necessary information for the calculation of the Scheduled Exchanges.	Article 43 (2)
15	Calculation of the Scheduled Exchanges	SEC	-	Each SEC shall calculate Scheduled Exchanges between Bidding Zones for each Market Time Unit.	Article 49 (1)
16	Sending of the agreed Scheduled Exchanges	SEC	TSOs, NEMOs, CCPs, SAs	Each SEC shall notify relevant NEMOs, CCPs, SAs and TSOs of the agreed Scheduled Exchanges.	Article 49 (2)
17a	Sending of the Scheduled Exchanges in terms of the Clearing and Settlement	SEC	CCP	Each SEC shall notify relevant CCPs of the agreed Scheduled Exchanges.	Article 49 (2)
17b	Sending of the Net Positions in terms of the Clearing and Settlement	NEMO	CCP	The clearing and settlement process shall also consider the NOME products.	
18a	Share of Exchanges of Energy	CCP	CCP	CCPs shall act as counter party to each other for the exchange of energy between Bidding Zones with regard to the financial rights and obligations arising from these energy	Article 68 (3)

				exchanges.	
18b	Share of Exchanges of Energy	SA	CCPs	A SA may act as a counter party between different CCPs for the exchange of energy, if the parties concerned conclude a specific agreement to that effect	Article 68 (6)
19	Clearing and Settlement of Energy Trades	CCP	Participants	The CCPs shall act as the counter party to Participants for all their trades with regard to the financial rights and obligations arising from these trades.	Article 68 (1)
20	Transfer of Congestion Income	CCP or SA	Congestion Income Distributor	All CCPs or SAs shall ensure that collected congestion incomes are transferred to the TSOs.	Article 68 (8)
20a	Transfer of Congestion Income	CID	TSO	The CID distributes the Congestion Income to the TSOs according to the agreed sharing key.	
21	Congestion Income Distribution	TSO	TSO	TSOs shall distribute Congestion Incomes.	Article 73 (3)

Table 2-1: Timeline of processes pursuant to the provisions of the CACM Regulation

3 Participation in the Greek Day-Ahead Market

In this Chapter we record all the stakeholders participating in the Day-Ahead Market in Greece along with the categorization of the Entities they represent and the respective registries kept by the Market Operator, the Transmission System Operator and the RES and CHP Units Registry Operator.

3.1 Entities

The elementary programming unit bearing a Market Schedule in the context of the Greek Day-Ahead Market analyzed in this document is referred to as the Entity. The set of Entities includes all physical assets connected to the Transmission System or the Distribution System, as follows:

a) **Generating Unit:** Conventional Dispatchable Generating Unit with an installed capacity above 5 MW, which can follow Dispatch Instructions by the TSO. This category includes also the Dispatchable CHP Units above 35 MW, as referred in the Hellenic Transmission System Operation Code, and the Auto-Producer Conventional Units, namely the conventional dispatchable Generating Units of Auto-Producers (or Self-Supplying Consumers).

   Representative Participant: Producer

b) **Non-Dispatchable Load Portfolio**: Portfolio (aggregation) of individual loads which **cannot** follow Dispatch Instructions by the TSO.

   Representative Participant: Load Representative

c) **Dispatchable Load Portfolio:** One individual load or a portfolio of individual loads which **can** follow Dispatch Instructions by the TSO.

   Representative Participants: Load Representative for the energy supply and for adjusting its demand based on economic signals (demand-response)

d) **RES Unit:** An individual RES Unit which directly participates in the wholesale electricity market. A RES Unit comes under one of the categories 1(b), 2, 3(b), 4, 5 or 6 presented in Annex C.

   Representative Participant: RES Producer or RES Aggregator

f) **Dispatchable RES Portfolio:** Portfolio (aggregation) of RES Units of a specific RES category (e.g. wind plants, PV stations, etc.) located in a specific Bidding Zone, which participates in the wholesale electricity market and which (based on its technical capability) **can** follow Dispatch Instructions (on a portfolio basis) by the TSO. The RES units included in a Dispatchable RES Portfolio come under one of the categories 1(b) 2, 3(b), 4, 5 and 6 presented in Annex C.

Representative Participant: RES Aggregator, Last Resort Aggregator, RES Producer[11]

f) **Non-Dispatchable RES Portfolio:** Portfolio (aggregation) of RES Units of the same RES category (e.g. wind plants, PV stations, etc.) located in a specific Bidding Zone, which participates in the wholesale electricity market, but which **cannot** follow Dispatch Instructions by the TSO. The RES Units included in a RES Portfolio come under one of the categories 1(b), 2, 3(b), 4, 5 and 6 presented in Annex C.

Representative Participant: RES Aggregator, Last Resort Aggregator, RES Producer

g) **RES FiT Portfolio:** Portfolio (aggregation) of RES Units which shall not participate directly in the wholesale electricity market. The RES Units included in the RES FiT Portfolio come under one of the categories 1(a) or 3(a) (remuneration under a Feed-in-Tariff regime) presented in Annex C.

Representative Participant: RES and CHP Units Registry Operator

h) **Generating Unit in Commissioning or Testing Operation**: Generating Unit that has declared to the TSO a specific energy production schedule for the Delivery Day, due to commissioning operation or testing operation.

Representative participant: Transmission System Operator

i) **RES Unit in Commissioning or Testing Operation**: RES Unit that has declared to the TSO a specific energy production schedule for the Delivery Day, due to commissioning operation or testing operation.

Representative participant: Transmission System Operator

We should note the following, regarding the Entities presented above:

1) The RES Aggregator referred in the above list can alternatively be the Last Resort Aggregator referred in the recent Greek Law 4414/2016 (concerning the new remuneration scheme of RES units in Greece). **For simplification purposes, in the remaining of this report we will use only the term RES Aggregator when referring to the representative of a RES Portfolio, without excluding the possibility for the representative to be the Last Resort Aggregator or a RES**

[11] A RES Producer can represent the RES Units registered in its Participant Account only, either on a unit-basis, or on portfolio-basis.

Producer.

2) An individual RES Unit can be also represented by a RES Aggregator (or the Last Resort Aggregator), but as a single Entity (being itself a RES Portfolio).

3.2 Participants

The Participants representing one or more Entities are the following:

a) Producers representing (on a unit basis) Generating Units (including Auto-Producer Conventional Units),

b) Load Representatives representing Non-Dispatchable Load Portfolios and/or Dispatchable Load Portfolios,

c) RES Producers representing Dispatchable and Non-Dispatchable RES Portfolios (i.e., a Portfolio of RES units of the same RES category located in a specific Bidding Zone),

d) RES Aggregators representing Dispatchable and Non-Dispatchable RES Portfolios,

e) the Last Resort Aggregator representing Dispatchable and Non-Dispatchable RES Portfolios,

f) TSO representing RES Units in Commissioning or Testing Operation and a Generating Units in Commissioning or Testing Operation, and

g) RES and CHP Units Registry Operator representing the RES FiT Portfolio and High-Efficiency Cogeneration Dispatchable Unit.

3.3 Registries

For the scope of the Forward Market, Day-Ahead Market and Intra-Day Market operation, the Market Operator shall keep a registry for all Participants.

In addition, the Transmission System Operator shall keep separate registries for the Generating Units, the Dispatchable Load Portfolios, the DR portfolios, the Dispatchable RES Units and the Dispatchable RES Portfolios; the TSO shall pass to the Market Operator the necessary information of these registries, for the purposes of the herein described Day-Ahead Market operation. The registries maintained by the TSO are analytically described in the detailed design of the Balancing and Ancillary Services Market.

Finally, the RES and CHP Units Registry Operator shall keep separate registries for the Dispatchable RES Units, the Non-Dispatchable RES Units, the Dispatchable RES Portfolio, the Non-Dispatchable RES Portfolio, the RES Units in Commissioning or Testing

Operation and the Dispatchable CHP Units. The RES and CHP Units Registry Operator shall pass to the Market Operator the necessary information of these registries, for the purposes of the herein described Day-Ahead Market operation.

3.4 Energy Trading System

The Market Operator shall operate an Energy Trading System, which shall comprise of a Trading Platform, a Registration and Nomination Platform and a Clearing Platform depending on the selection of the Clearing House.

Trading shall take place through the Trading Platform. Participants shall submit Orders from their respective workstations to the Market Operator's Trading Platform by electronic means. The Trading Platform shall be used for receiving, validating and storing of Orders, anonymizing and sending the Orders to the Market Coupling Operator that is responsible for the matching of the Orders for the Day-Ahead Market Coupling, receiving the anonymized market coupling results, decrypting the results with respect to the Participants and the Entities concerned, and notifying the market results to the Participants. The Trading Platform shall also be used in case of enforcement of the fallback procedures described in Chapter 9 of this report.

The Registration and Nomination Platform shall be used for the registration of the Forward Contracts and the submission of Physical Delivery Nominations and Physical Offtake Nominations by the Participants, which shall be submitted to the Day-Ahead Market with Priority Price-Taking Orders as detailed in Section 6.3.3. The accepted Sell and Buy Orders of the Day-Ahead Market Results, beyond the Priority Price-Taking Orders related to the Physical Delivery Nominations and Physical Offtake Nominations, are also transferred to the Registration and Nomination Platform.

Finally, the Clearing Platform shall be used for the Clearing, Settlement and Risk Management procedures of the Clearing House.

Access to the Trading Platform, the Registration and Nomination Platform and the Clearing Platform is provided by the Market Operator for the Certified Users of the Participants according to the relevant provisions of the Registration and Participation Rules. Access to the Clearing Platform may be subject to additional rules set by the Clearing House.

Access to the Registration and Nomination Platform is provided by the Market Operator for the Certified Users of the Transmission System Operator for the purpose of fulfillment of its obligations according to the provisions of the respective Market Codes.

3.5 Participation Requirements

Participation in the Day-Ahead Market prerequisites:

a) a valid Participation Agreement with the Market Operator;

b) a valid and duly signed Financial Agreement either directly or indirectly (through a Clearing Member) with the Market Operator or the Clearing House; and

c) a valid and duly signed Balancing Contract with the Transmission System Operator.

3.6 Participation Rules

First of all, it should be noted that participation in the Day-Ahead Market is optional for all Participants except from the Producers. The Day-Ahead Market constitutes a compulsory market for Producers, which are obligated to submit Sell Orders in the Day-Ahead Market for the Available Capacity of the Generating Units they represent, which has not been already allocated via Physical Delivery Nominations of Exchange Based Forward Market Contracts and Bilateral OTC Contracts. More specifically, participation in the Day-Ahead Market shall mean in particular:

a) the submission of Sell Orders by Producers for each Generating Unit registered in their Participant Account for energy injection up to the Generating Unit's Available Capacity which is not allocated via Physical Delivery Nominations;

b) the submission of Buy Orders by Producers for each Generating Unit registered in their Participant Account for Physical Delivery Position Correction and/or energy withdrawal for the Auxiliary Loads of the Generating Units registered in their Participant Account;

c) the submission of Sell Orders by RES Producers for each Dispatchable and Non-Dispatchable RES Portfolio registered in their Participant Account for energy injection up to the sum of the Available Capacities of the RES Units included in the RES Portfolio, which is not allocated via Physical Delivery Nominations;

d) the submission of Buy Orders by RES Producers for each Dispatchable and Non-Dispatchable RES Portfolio registered in their Participant Account for Physical Delivery Position Correction and/or energy withdrawal for the Auxiliary Loads of the RES Units included in the RES Portfolio;

e) the submission of Sell Orders by RES Aggregators for each Dispatchable and Non-Dispatchable RES Portfolio registered in their Participant Account for energy injection up to the sum of the Registered Capacities of the RES Units included in the RES Portfolio, which is not allocated via Physical Delivery Nominations;

f) the submission of Buy Orders by RES Aggregators for each Dispatchable and Non-Dispatchable RES Portfolio registered in their Participant Account for Physical Delivery Position Correction and/or energy withdrawal for the Auxiliary Loads of the RES Units included in the RES Portfolio;

g) the submission of Buy Orders by Suppliers and Self-Suppliers, acting as Load Representatives for local consumers for each Dispatchable and Non-Dispatchable Load Portfolio registered in their Participant Account, for energy withdrawal which is not allocated via Physical Offtake Nominations;

h) the submission of Sell Orders by Suppliers and Self-Suppliers, acting as Load Representatives for local consumers for each Dispatchable and Non-Dispatchable Load Portfolio registered in their Participant Account, for Physical Offtake Position Correction;

i) the submission of Sell Orders by Traders, Suppliers and Self-Suppliers which have acquired Long-Term Physical Transmission Rights in coupled interconnections and Long-Term and Short-Term Physical Transmission Rights in non-coupled interconnections, for Imports which is not allocated via Physical Delivery Nominations;

j) the submission of Buy Orders by Traders, Suppliers, Producers, RES Producers and RES Aggregators which have acquired Long-Term Physical Transmission Rights in coupled interconnections and Long-Term and Short-Term Physical Transmission Rights in non-coupled interconnections, for Exports which is not allocated via Physical Offtake Nominations;

k) the submission of Priority Price-Taking Sell Orders by the Transmission System Operator for the scheduled production of each Generating Unit in Commissioning or Testing Operation and each RES Portfolio for RES Units in Commissioning or Testing Operation and for the Mandatory Hydro Injections for each Hydro Unit;

l) the submission of Priority Price-Taking Buy Orders by the Transmission System Operator for the forecasted Transmission System Losses;

m) the submission of Priority Price-Taking Sell Orders by the Last Resort RES Aggregator for the forecasted production of each RES Portfolio;

n) the submission of Priority Price-Taking Sell Orders by the RES and CHP Units Registry Operator, for the forecasted production of each RES FiT Portfolio and for the Priority Declarations of each High-Efficiency Cogeneration Dispatchable Unit;

o) the submission of Priority Price-Taking Sell /Buy Orders by the Market Operator for the energy quantities of the Exchange Based Forward Market that have been nominated in the Registration and Nomination Platform through validated Physical Delivery Nomination /Physical Offtake Nominations; and

p) the submission of Priority Price-Taking Sell /Buy Orders by the Market Operator for the energy quantities of Bilateral OTC Contracts that have been nominated in the Registration and Nomination Platform through validated Physical Delivery Nomination /Physical Offtake Nominations.

Additional participation rules that shall be implemented in the framework of the Day-Ahead Market are the following:

a) Producers shall submit Techno-Economic Declarations for each Generating Unit registered in their Participant Account according to the provisions of the Balancing Market Code.

b) Producers and RES Producers shall submit Total or Partial Non-Availability Declarations for each Generating Unit and RES Unit registered in their Participant Account, respectively, according to the provisions of the Balancing Market Code.

c) RES Aggregators representing Dispatchable and/or Non-Dispatchable RES Portfolios are not required to submit Total or Partial Non-Availability Declarations.

d) The energy quantities included in the Sell Orders are deemed to be injected at the Meter Point.

e) The energy quantities included in the Buy Orders are deemed to be withdrawn at the Transmission-Distribution Boundary.

3.7 Participation Fees

The Participants shall pay fees for the trading services provided by the Market Operator. The overall fees shall comprise the following components:

A) Annual Fee, separately for each market (Forward, Day-Ahead and Intra-Day Market); the Annual Fee represents the cost of trading services for the participation in the markets, and it shall be a fixed amount per year,

B) Membership Fee, separately for the Forward Market and for the spot market (Day-Ahead and Intra-Day Markets);

C) Transactions Fee, for each MWh traded (both bought and sold) by each Participant.

The Membership Fee constitutes a one-off payment to all newly-admitted Participants. The Membership Fee shall be due on the Participation Commencement Day.

The Annual Fee in the first year shall be due on the Participation Commencement Day. The annual fee for every subsequent year Y shall be due five (5) Working Days before the start of the calendar year Y. No refund shall be given by the Market Operator to the Participant in case of termination during a year.

The Transactions Fee shall be charged to the Participants for the execution of Orders. Thus, transaction fees depend on the executed volume in Megawatt hours (MWh). The Transactions Fee shall be due in the 5th Working Day of calendar month M+1 for the energy transactions concluded in calendar month M.

The fees shall be collected directly by the Market Operator, following the issuance of a respective invoice to each Participant.

The values of the above fees (Membership Fee, Annual Fee and Transactions Fee) shall be established for each calendar year by a decision by the Regulator following a proposal of the Market Operator.

4 Interface of the Forward Market with the Day-Ahead Market

4.1 Introduction

This Chapter presents the interface of the Forward Market with the Day-Ahead Market, namely the process followed for the Physical Settlement of the Forward Contracts. Furthermore, this Chapter briefly describes the process corresponding to the Financial Settlement of the Forward Contracts.

4.2 Physical Settlement of Forward Contracts: Registration

This Section presents the methodology used for calculating the Net Delivery Positions and the process for the registration of these Positions separately for the Exchange Based Forward Contracts and the Bilateral OTC Contracts by the Clearing House.

4.2.1 Forward Contracts Registration

As already discussed in the Detailed Design Report of the Greek Forward Market, Participants have the obligation of arranging for the actual **Physical Delivery** of the electricity as expressed in their overall Net Delivery Position in the forward timescale, in the Day-Ahead Market. In the following we present a brief review of the procedures concerning the arrangements for the Physical Delivery of the transacted quantities in the forward timescale.

Standard Year Contracts and Standard Quarter Contracts ultimately cascade into Standard Month Contracts. **Thus, the Physical Settlement of any Forward Contract (year, quarter, month) refers to the arrangements that take place for the actual delivery of the electricity underlying each (cascaded) Standard Month Contract (arrangements for the injection or withdrawal of energy in the Transmission System during the Delivery Period).**

> **The Exchange Based Forward and the Bilateral OTC Contract quantities are contracted on a portfolio basis.**

Standard Month Contracts as well as Bilateral OTC Contracts shall be physically settled, through registration on a **dedicated Registration and Nomination Platform** of the electricity underlying each contract. First of all, the Market Operator shall determine the **Exchange Based Net Delivery Position (NDP_X)** and the **Bilateral OTC Net Delivery Position (NDP_{BOTC})** of each Participant, with regard to all the Delivery Hours of the Delivery Day D as described in the subsection 4.2.2. The relevant NDPs computations shall be made in the Registration and Nomination Platform, immediately after the Forward Contracts Registration Gate Closure Time in day D-2, as shown in Figure 4-1.

As mentioned above, the Market Operator operates an electronic Registration and Nomination Platform where the Clearing House acting on behalf of the Participants having traded energy quantities on the Forward Market must register the corresponding energy quantities for all Delivery Periods of each Delivery Day depending on the calculated NDPs. The Exchange Based Forward Contracts and the Bilateral OTC Contracts shall subsequently be physically settled through Physical Delivery Nominations and Physical Offtake Nominations (to be inserted as Priority Price-Taking Orders in the Day-Ahead Market).

The electronic platform shall be open (a) for the submission of registration of the Forward Contracts and (b) for the submission of the Physical Delivery / Offtake Nominations (see below in Section from 10:00 EET 30 calendar days before the Delivery Day to 10:00 EET one calendar day before the Delivery Day (D-1) for the energy quantities (both of the Exchange Based Forward Contracts and the Bilateral OTC Contracts) corresponding to the Delivery Periods of Delivery Day D.

4.2.2 Calculation of the Net Delivery Positions

For each Delivery Hour *h* of the Delivery Day D, the Exchange Based Net Delivery Position (NDP_X) for each Participant *p* shall be calculated as the sum of the purchase minus the sale of the Exchange Based Forward Contracts that include the said Delivery Period, concluded by the Participant in the Exchange Based Forward Market.

For each Delivery Hour *h* of the Delivery Day D, the Bilateral OTC Net Delivery Position (NDP_{BOTC}) for each Participant shall be calculated as the sum of the purchase minus the sale of Bilateral OTC Contracts concluded by the Participant.

The above mentioned calculation, that requires the registration of every Forward Contract that has been concluded in the forward timescale in the Registration and Nomination Platform, will ensure the stability of all the forward processes and consequently the security of the power system. It will underpin the process of transferring volume-related data concerning the forward procedures directly to the Day-Ahead Market operation by the Market Operator.

4.3 Physical Settlement of Forward Contracts: Nomination

All the forward processes shall be performed by the Participants on a portfolio basis, meaning that Orders in the Forward Market shall refer to the participants' portfolio, without ex-ante defining the Entities that shall be involved in the energy trading.

4.3.1 Physical Delivery Nominations

As far as the Physical Delivery of the forward quantities is concerned, the Producers, RES Producers, RES Aggregators and Traders performing imports utilizing their Long-Term PTRs must allocate the energy quantities included in the Forward Contract Registrations to their production resources or to imports per interconnection, for the physical settlement of the electricity underlying the Exchange Based Net Delivery Position (NDP_X) and the Bilateral OTC Net Delivery Position (NDP_{BOTC}). Participants having multiple roles may include in their Physical Delivery Nominations any possible set of Generating Units, RES Units and RES Portfolios and imports, in order to cover the sum of their positive amounts of NDP_X and NDP_{BOTC} under the condition that the sum of the nominated energy quantities included in the Physical Delivery Nominations is exactly equal to their NDP_{pos} as calculated in Section 6.2 of the Detailed Design Report of the Forward Market.

The Physical Delivery Nominations shall be allocated at the latest by the Physical Delivery Nomination Gate Closure Time in day D-1 for the Delivery Day D which is 10:00 EET in day D-1, as follows:

a) per Generating Unit by the Producers,

b) per RES Unit or per RES Portfolio registered in the Participant Account of a RES Producer ,

c) per RES Portfolio represented by a RES Aggregator,

d) per border by the Participants utilizing their long-term import PTRs.

Physical Delivery Nominations shall include at least the following information:

a) the Delivering Participant EIC Code;

b) the Generating Unit EIC Code or RES Unit EIC Code or RES Portfolio EIC Code or interconnection EIC Code;

c) the Delivery Day and Delivery Period; and

d) the energy quantity to be generated / imported, in MWh up to 3 decimal points.

Physical Delivery Nomination may be submitted many times by each Participant. The most updated Physical Delivery Nomination submitted by the Physical Delivery Nomination Gate Closure Time (10:00 EET in day D-1) is considered as the Physical Delivery Nomination for the corresponding Entities.

The Physical Delivery Nominations must respect each Generating Unit's and RES Unit's Available Capacity.

4.3.2 Physical Offtake Nominations

Offtake is electricity absorption (demand) through a system node. As we have discussed in the Detailed Design Report of the Forward Market, speculation opens the window so that Forward Contracts have an option of physical delivery, which is against the Law 4425/2016. For this reason, penalization is opted here. This applies to delivery nominations and to offtake nominations.

With respect to Physical Offtake of the forward quantities, the Suppliers, Self-Suppliers and Traders performing exports utilizing their Long-Term PTRs must allocate the energy quantities included in the Forward Contract Registrations to their load entities or to exports per interconnection, for the physical settlement of the electricity underlying the Exchange Based Net Delivery Position (NDP_X) and the Bilateral OTC Net Delivery Position (NDP_{BOTC}). Participants having multiple roles may include in their Physical Offtake Nominations Auxiliary Loads of their Generating Units, RES Units, and RES Portfolios, energy withdrawal for Dispatchable and Non-Dispatchable Load Portfolios acting as Load Representatives and exports, in order to cover NDP_{neg} under the condition that the sum of the nominated energy quantities included in the Physical Offtake Nominations is exactly equal to their NDP_{neg}.

The Physical Offtake Nominations shall be allocated at the latest by the Physical Delivery Nomination Gate Closure Time in day D-1 for the Delivery Day D which is 10:00 EET in day D-1, as follows:

a) per Dispatchable Load Portfolio and/or Non-Dispatchable Load Portfolio by Suppliers and Self-Suppliers;

b) per Generating Unit or per RES Unit for the Auxiliary Loads by Producers and RES Producers, respectively; and

c) per border by the Participants utilizing their long-term export PTRs.

Physical Offtake Nominations shall include at least the following information:

a) the Participant EIC Code;

b) the Non-Dispatchable Load Portfolio EIC Code or Dispatchable Load Portfolio EIC Code or Generating Unit Offtake EIC Code or RES Unit Offtake EIC Code or the interconnection EIC Code;

c) the Delivery Period and the Delivery Day; and

d) the energy quantity to be consumed or to be exported, in MWh up to 3 decimal points.

Physical Offtake Nominations must be submitted at the latest by the Physical Delivery Nomination Gate Closure Time. Physical Offtake Nomination may be submitted many times by each Participant. The most updated Physical Offtake Nomination submitted by the Physical Delivery Nomination Gate Closure Time is considered as the Physical Offtake Nomination of the corresponding load entities or exports per interconnection.

4.3.3 Information provided by the TSO to the Market Operator in terms of the Validation Checks

The TSO provides the following information to the Market Operator during calendar day D-1 for the Delivery Day D:

1) the nominated Long-Term Physical Transmission Rights (LT PTRs) per border and per direction for both imports and exports for each Delivery Period of the Delivery Day D, until thirty (30) minutes after the latest[12] LT PTRs Nomination Gate Closure Time at day D-1;

2) the Available Capacity of each Generating Unit and each RES Unit for each Delivery Period of the Delivery Day D, as analytically described in the Detailed Design Report of the Forward Market; and

3) the Entities registered in each Participant Account defining the Participant Portfolio.

4.3.4 Validation checks performed by the Market Operator

The Physical Delivery Nominations and Physical Offtake Nominations are submitted sequentially by each Participant. In each successful submission, the Registration and Nomination Platform recalculates for each Delivery Hour of the Delivery Day the remaining quantity, $NDP_{pos\text{-}rem}$ and $NDP_{neg\text{-}rem}$ respectively, to be covered through Physical Delivery Nominations and Physical Offtake Nominations for each Participant.

Following the submission of Physical Delivery Nominations and Physical Offtake Nominations by the Participants, the Registration and Nomination Platform of the Market Operator performs the following four (4) validation checks:

1st validation check: In case the energy quantity included in a Physical Delivery Nomination is higher than the remaining quantity $NDP_{pos\text{-}rem}$ for one or more Delivery Periods of the Delivery Day, then the Physical Delivery Nomination is considered as non-valid.

[12] In case there are more than one LT PTRs Nomination Gate Closure Times.

2nd validation check: In case the energy quantity included in a Physical Offtake Nomination is higher than the remaining quantity $NDP_{neg\text{-}rem}$ for one or more Delivery Periods of the Delivery Day, then the Physical Offtake Nomination is considered as non-valid.

3rd validation check: In case the energy quantity allocated to a Generating Unit by a Producer or to a RES Unit by a RES Producer is higher than the Available Capacity of such Generating Unit or RES Unit, respectively, then the Physical Delivery Nomination for this Unit is considered as non-valid.

4th validation check: In case the energy quantity allocated to an interconnection for imports or exports is higher than the nominated LT PTRs at the same interconnection, then this Physical Delivery Nomination and Physical Offtake Nomination, for the respective interconnection is considered as non-valid.

Immediately after performing the validation checks described above, the Registration and Nomination Platform informs the Participants concerning the validity or rejection of a Physical Delivery Nomination or a Physical Offtake Nomination. In each successful submission, the Registration and Nomination Platform recalculates for each Delivery Period of the Delivery Day the remaining quantity, $NDP_{pos\text{-}rem}$ and $NDP_{neg\text{-}rem}$ respectively, to be covered through Physical Delivery Nominations and Physical Offtake Nominations for each Participant.

4.3.5 Actions of the Market Operator in case of failed validation checks

Following the above-mentioned validation checks and after the Physical Delivery Nomination Gate Closure Time, the Market Operator issues either:

a) a confirmation that the submitted Physical Delivery Nominations and Physical Offtake Nominations fully covers the $NDP_{pos\text{-}rem}$ and $NDP_{neg\text{-}rem}$ respectively; in such case, the Participant is not allowed to perform any changes in the submitted and validated Physical Delivery Nominations and Physical Offtake Nominations; or

b) a notification that the submitted Physical Delivery Nominations and Physical Offtake Nominations do not fully cover the $NDP_{pos\text{-}rem}$ and $NDP_{neg\text{-}rem}$ respectively, stating the $NDP_{pos\text{-}rem}$ and $NDP_{neg\text{-}rem}$ per Delivery Period; in such case, the Participant is obliged to submit additional Physical Delivery Nominations and/or Physical Offtake Nominations at the latest thirty (30) minutes after the Physical Delivery Nomination Gate Closure Time;

   in case:

   (1) the Participant does not submit additional Physical Delivery Nominations, or

(2) the submitted additional Physical Delivery Nominations, do not fully cover the $NDP_{pos\text{-}rem}$, then the Market Operator calculates for each Participant p and for each Delivery Period t of Delivery Day d the Participant Positive Forward Market Mismatch Quantity, $PPFMMQ_{p,t,d}$, as follows:

$$PPFMMQ_{p,t,d} = NDP_{pos} - \sum_{i=1}^{N} PDN_i$$

where *N* is the total number of Physical Delivery Nominations submitted for the Delivery Period *t*, and *i* is the index of Physical Delivery Nominations submitted for the Delivery Period *t*.

Then, the Market Operator applies a Non-Compliance Charge calculated equal to the product of the absolute value of the Participant Positive Forward Market Mismatch Quantity, $PPFMMQ_{p,t,d}$ and an Administratively Defined Position Nomination Penalty Price.

In case:

(1) the Participant does not submit additional Physical Offtake Nominations, or

(2) the submitted additional Physical Offtake Nominations do not fully cover the $NDP_{neg\text{-}rem}$, the Market Operator calculates for each Participant p and for each Delivery Period t of Delivery Day d the Participant Negative Forward Market Mismatch Quantity, $PNFMMQ_{p,t,d}$, as follows:

$$PNFMMQ_{p,t,d} = NDP_{neg} - \sum_{i=1}^{N} PON_i$$

where *N* here is the total number of Physical Offtake Nominations submitted for the Delivery Period *t*, and *i* is the index of Physical Offtake Nominations submitted for the Delivery Period *t*.

Then, the Market Operator imposes a Non-Compliance Charge calculated equal to the product of the absolute value of the Participant Negative Forward Market Mismatch Quantity, $PNFMMQ_{p,t,d}$ and an Administratively Defined Position Nomination Penalty Price.

The value of the Administratively Defined Position Nomination Penalty Price shall be proposed by the Market Operator and approved by the Regulator. Such decision shall be taken at least two months prior to the end of a calendar year, it shall be in force for the next calendar year and it cannot be modified within such year

➢ **Example**:

Suppose that a Participant A, which is registered in Greece, acquires 10 MW yearly PTRs for imports in the interconnection of Bulgaria, and 5 MW monthly PTRs for imports in the same interconnection, for month April.

Suppose now, that this Participant A has sold 15 MWh/hour for a whole certain day D of April to another Participant B, through a bilateral OTC transaction. As it is clearly established, the Clearing House should register this bilateral transaction till 17:00 EET in day D-2 to the Registration and Nomination Platform, in order to effectuate this transaction and notify the Market Operator and the TSO.

Suppose also, that with regard to this certain day D of April, until the Long-Term PTRs Nomination Gate Closure Time in day D-1, the Participant A has nominated 13 MW (out of the 15 MW of PTRs) for imports to Greece for the whole day D, specifying his counterparty in the Bulgarian side (Participant C). In this context, the Participant A has three options:

1. *either to use the imports of 13 MWh/hour (using his long-term PTRs), in order to effectuate the Physical Delivery of the bilateral OTC transaction with Participant B, for the Delivery Day D, along with the use of another source to cover the remaining 2 MWh/hour of the bilateral OTC transaction,*

2. *or to use one or more of his Generating Units (if any) to cover the 15 MWh/hour of his bilateral OTC transaction with Participant B, for the Delivery Day D,*

3. *or not to declare any source for the sold energy quantities until the Physical Delivery Nomination Gate Closure Time (namely, until 10:00 EET in day D-1), in which case he will be speculating in the Forward Market (knowing that he is subject to the Day-Ahead Market price volatility). This situation (speculation) is not acceptable, and the Participant A shall be subject to a non-compliance charge, as described in this Section 4.3.5 above.*

Obviously, any possible combination of the first two above-mentioned options to cover the bilateral contracted energy of 15 MWh/hour is also acceptable (e.g. 8 MWh/hour from imports and 7 MWh/hour from his Generation Units).

Now, in case the Participant A declares until the Physical Delivery Nomination Gate Closure Time (namely, until 10:00 EET in day D-1) the use of e.g. 15 MWh/hour from imports from Bulgaria, in order to cover the bilateral contract with Participant B for the Delivery Day D, then the Registration and Nomination Platform shall reject the submitted nomination. The Participant has another thirty (30) minutes to correct the nomination and submit it again to the Registration and Nomination Platform. In case a non-valid nomination is finally submitted, the Participant is subject to the non-compliance charge described above.

4.3.6 Physical Delivery of the validated Physical Delivery and Offtake

Nominations

The energy quantities of the validated Physical Delivery and Offtake Nominations shall be physically settled through the submission of Priority Price-Taking Orders in the Day-Ahead Market by the Market Operator on behalf of the Participants and their acceptance in the Day-Ahead Market results.

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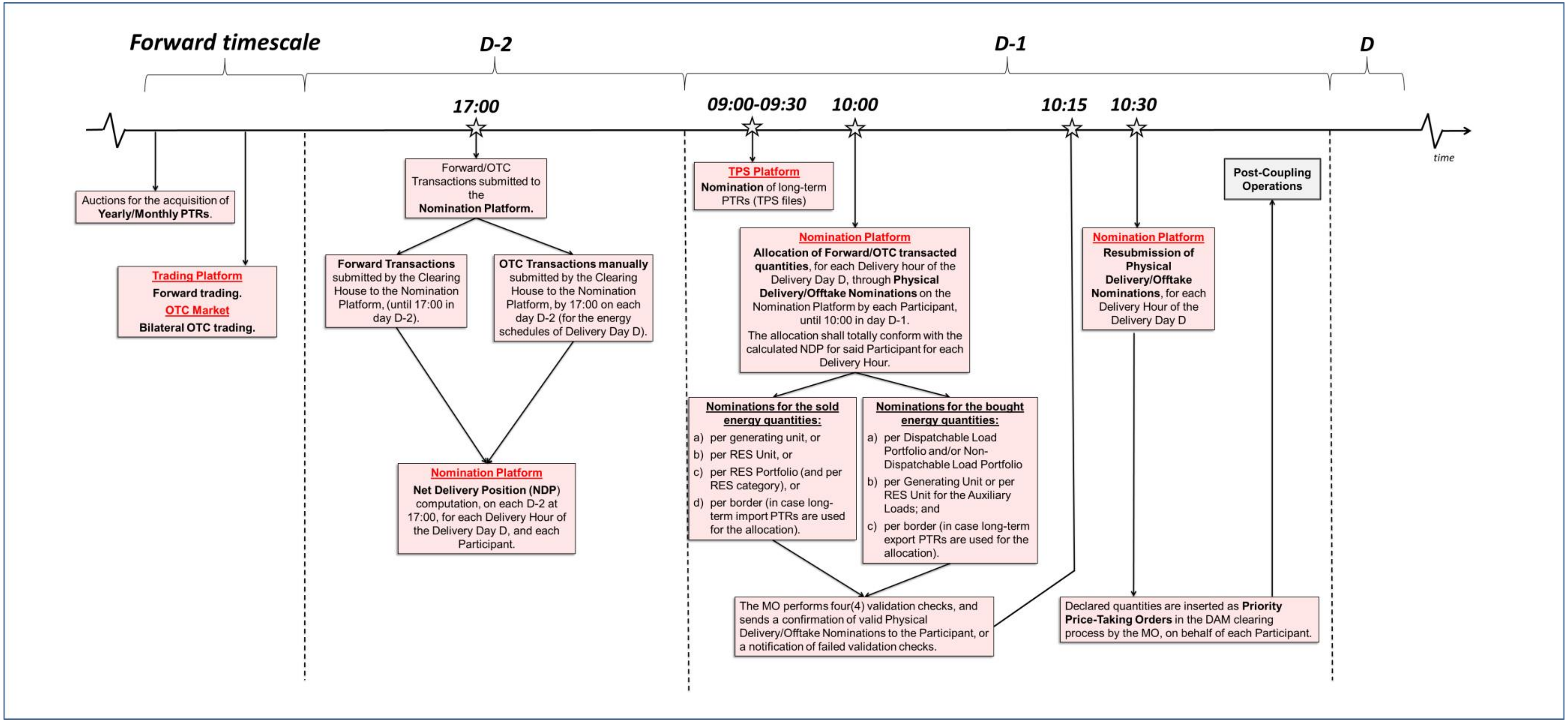

Figure 4-1: Basic timeline and processes in the Forward Market (timing is in EET in this Figure)

4.4 Financial Settlement of Forward Contracts

As regards the Financial Settlement procedures in the Forward Market, as already discussed in the detailed design report of the Forward Market:

a) The contracted quantities in the Forward Market are settled only with the Variation Margins in the forward timeframe and the spot-referenced settlement procedure during the Delivery Period of each Forward Contract. **Therefore, the declared / allocated forward quantities will also have to be settled in the Day-Ahead Market clearing and settlement process (using the Day-Ahead Market prices).**

b) **This is not the case with the Bilateral OTC Contracts, which are financially settled through the Clearing House. In this context, no settlement of bilateral declared quantities shall be performed in the Day-Ahead Market using the respective market prices.**

The following example is intended to clarify the above-mentioned procedure with regard to a Forward Transaction, along with the Financial Settlement for the Participants involved. For simplicity, only one Forward Transaction is considered below.

Suppose that the following Forward Transaction has been made in the Exchange Based Forward Market: Participant A has sold 20 MW for 50 €/MWh on the baseload Standard Month Contract, for the month of July.

The following Figure, illustrates the procedures and timelines with regard to the calculation of the NDPs for said Participants, the allocation of the forward quantities (Participant A declares to produce 20 MW from his Generating Unit in the North zone, while Participant B declares to consume 20 MW in the South zone of Greece), and the insertion of the declared quantities as "Priority Price-Taking" Orders in the Day-Ahead Market.

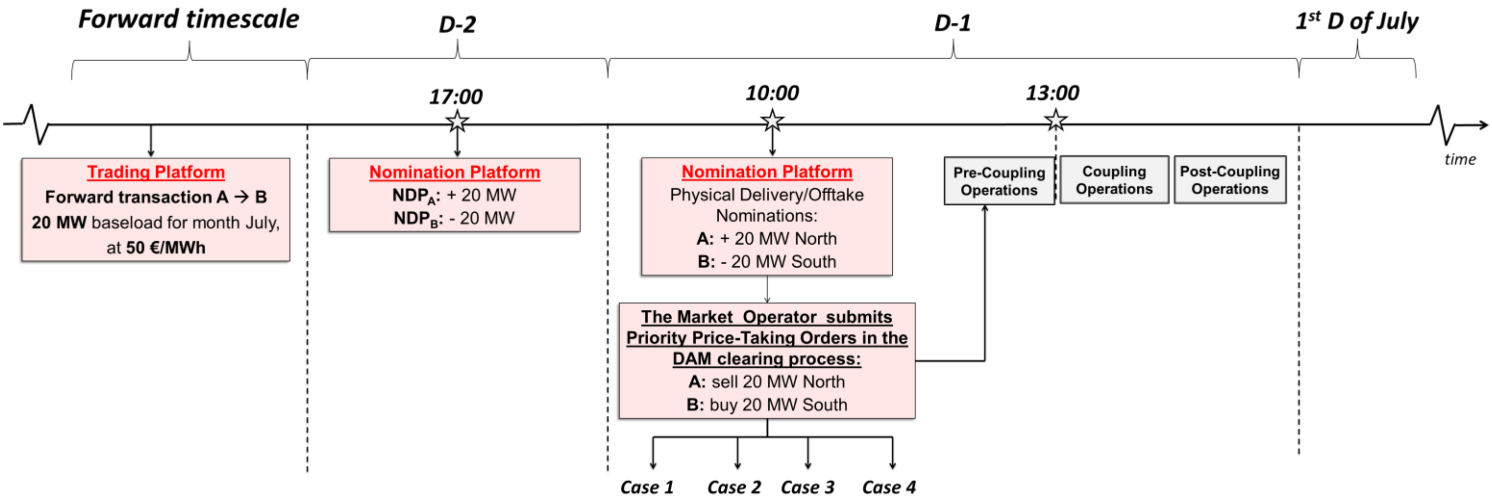

Figure 4-2: Example - Forward Contracts Registration and Nomination and submission of Priority Price-Taking Orders in the Day-Ahead Market (timing is in EET in this Figure)

Cases 1, 2, 3, 4 in the following, present the Financial Settlement in both the Exchange Based Forward Market (FM) and the Day-Ahead Market (where the Physical Delivery of the forward transacted quantity takes place) for the Participants involved in the Forward Transaction. For simplicity, we present the corresponding profits and losses, only with regard to a random hour of the first Delivery Day of July. Of course, we assume that the Clearing House intermediates in all settlement procedures.

***Case 1**: The DAM clears at 40 €/MWh, both in the North and the South zone.*

$$\text{Participant } A: \left.\begin{cases} FM: \ (50-40) \text{ €/MWh} * 20 \text{ MWh} = +200 \text{ €} \\ DAM: \ +40 \text{ €/MWh} * 20 \text{ MWh} = +800 \text{ €} \end{cases}\right\} \text{Total}: +1000\text{ €}$$

$$\text{Participant } B: \left.\begin{cases} FM: \ (40-50) \text{ €/MWh} * 20 \text{ MWh} = -200 \text{ €} \\ DAM: \ -40 \text{ €/MWh} * 20 \text{ MWh} = -800 \text{ €} \end{cases}\right\} \text{Total}: -1000\text{ €}$$

***Case 2**: The DAM clears at 60 €/MWh, both in the North and the South zone.*

$$\text{Participant } A: \left.\begin{cases} FM: \ (50-60) \text{ €/MWh} * 20 \text{ MWh} = -200 \text{ €} \\ DAM: \ +60 \text{ €/MWh} * 20 \text{ MWh} = +1200 \text{ €} \end{cases}\right\} \text{Total}: +1000\text{ €}$$

$$\text{Participant } B: \left.\begin{cases} FM: \ (60-50) \text{ €/MWh} * 20 \text{ MWh} = +200 \text{ €} \\ DAM: \ -60 \text{ €/MWh} * 20 \text{ MWh} = -1200 \text{ €} \end{cases}\right\} \text{Total}: -1000\text{ €}$$

***Case 3:** The DAM clears at 40 €/MWh in the North zone and at 45 €/MWh in the South zone. The unconstrained System Marginal Price[13] is 42 €/MWh.*

$$\text{Participant } A: \left.\begin{cases} FM: \ (50-42) \text{ €/MWh} * 20 \text{ MWh} = +160 \text{ €} \\ DAM: \ +40 \text{ €/MWh} * 20 \text{ MWh} = +800 \text{ €} \end{cases}\right\} \text{Total}: +960\text{ €}$$

$$\text{Participant } B: \left.\begin{cases} FM: \ (42-50) \text{ €/MWh} * 20 \text{ MWh} = -160 \text{ €} \\ DAM: \ -45 \text{ €/MWh} * 20 \text{ MWh} = -900 \text{ €} \end{cases}\right\} \text{Total}: -1060\text{ €}$$

***Case 4**: The DAM clears at 55 €/MWh in the North zone and at 60 €/MWh in the South zone. The unconstrained System Marginal Price is 57.5 €/MWh.*

[13] Unconstrained System Marginal Price: the DAM SMP when the inter-zonal constraints are relaxed.

$$Participant\ A: \begin{cases} FM:\ (50-57.5)\ €/MWh\ *\ 20\ MWh = \text{-}150\ € \\ DAM:\ +55\ €/MWh\ *\ 20\ MWh = +1100\ € \end{cases} Total: +950\,€$$

$$Participant\ B: \begin{cases} FM:\ (57.5-50)\ €/MWh\ *\ 20\ MWh = +150\ € \\ DAM:\ -60\ €/MWh\ *\ 20\ MWh = \text{-}1200\ € \end{cases} Total: -1050\,€$$

It should be noted that no PUN Orders are present in the Greek Day-Ahead Market, so, in case of many Bidding Zones, even Load Representatives shall be cleared at the zonal market price (not at the production weighted average market price, as in Italy).

The hedging results as well as the "basis risk" of the Participants' participation in the Forward Market are revealed in this example.

In case a Seller is unable to allocate his NDP to his Entity(ies) due to technical unavailability (as submitted to and verified by the TSO through an Non-Availability Declaration and subsequently submitted to the Registration and Nomination Platform by the TSO), the Seller is able to buy this energy from the Day-Ahead Market in order to cover its Position and not to be imbalanced. The same applies for the Buyer who is able to correct his Physical Offtake Nomination Position by selling energy in the Day-Ahead Market.

5 Orders

5.1 Introduction

This Chapter presents the Orders allowed in the European Day Ahead Markets along with an analysis of their pros and cons. Further, this Chapter presents the types of orders allowed in the Greek Day-Ahead Market.

5.2 Orders Types in European Day-Ahead Markets

The types of Orders submitted in the European Day-Ahead Market for the DAM tradable products consist of the following:

- Simple step-wise and linear piecewise Orders,
- Block Orders (as in CWE, Nordpool, etc.), and
- Complex Orders (as in the Iberian market).

In the following, we present in detail each of the above types of Orders for generation and demand and provide an analysis of the advantages and disadvantages of each type for each role of the Participants. Inclusion of this analysis is critical to ensure that the Participants fully understand the new market instruments available to them to meet their objectives.

a. ***Simple Orders***

Simple Orders are increasing for generation and imports and decreasing for demand and exports, separate for each Market Time Unit of the Delivery Day.

Aggregated Sell and Buy Curves can be of the following types:

i. Linear piecewise curves (i.e. two consecutive points of the monotonous curve cannot have the same price, except for the first two points defined at the maximum / minimum prices of the Bidding Zone, as shown in *Figure 5-1*).

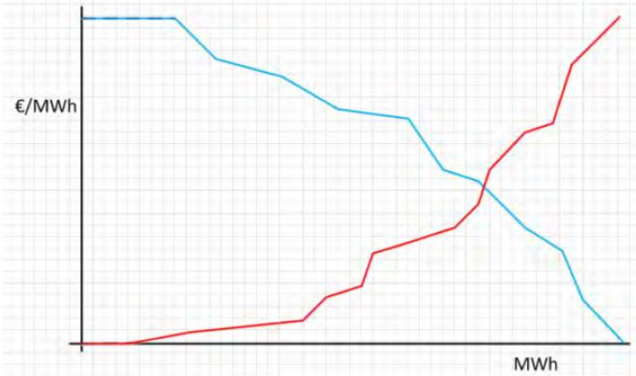

Figure 5-1: Linear Piecewise Curve

ii. Stepwise curves (i.e. two consecutive points always have either the same price or the same quantity, as shown in *Figure 5-2*).

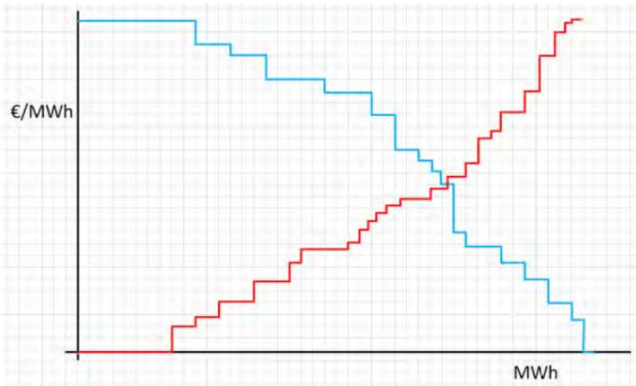

Figure 5-2: Stepwise Curve

iii. Hybrid curves (composed by both linear and stepwise segments).

The Simple Orders constitute the simplest way to submit Orders, but it is difficult for Producers to ensure feasible schedules and profitability for their Generating Units, due to the volatility of the DAM prices and the simplistic format of the Orders (lack of inter-temporal constraints, etc.).

Under perfect competition, we would expect to observe the following market characteristics under Simple Orders for generation and demand. First, Buy Orders will always be at or very close to marginal costs. Second, prices will almost always be above the marginal costs of most units that are generating and will sometimes rise quite high above the marginal cost of even the most expensive unit on-line. Third, not all units will be offered on-line during periods of low predicted prices.

> ***Simple Orders may not lead to feasible schedules or ensure profitability for the Generating Units.***

More precisely, in a world where all Producers act like perfect competitors, we would see the following kinds of bidding and generating behavior. **Generating Units would be bid into the market at or close to their marginal running cost, defined as (fuel cost) x (marginal heat rate) + variable operating and maintenance costs.** Generators such as gas turbines with no startup costs and no other non-convexities would be bid at exactly their marginal cost. Prices in this perfectly competitive world will be set according to a "system dispatch curve" established by stacking the marginal costs of all units in ascending order. As demand rises, higher cost units are brought in by raising the market-clearing price. Not coincidentally, this tracks the way a single integrated utility would dispatch its units. A generator will earn contributions to its fixed cost whenever its marginal cost is below the market clearing price. This is true even if the generator is never bid at more than its marginal cost. For example, base load units may bid in at zero or very close to zero and earn the hourly price each period. Bidding "higher than marginal cost to cover fixed costs" does not help them and in fact hurts their profitability. This observation is fundamental to the way marginal pricing works and the way it incents generators to bid their true marginal costs in the market.

> ***If there is persistent market power in a secondary market, or in another market (for example electricity vs gas), it can spill over to affect the bidding behavior of the Participants in the Day-Ahead Market.***

At times, the market-clearing price would rise above the marginal cost of any unit, sometimes dramatically so. This would occur when demand exceeded the capacity of all units scheduled to be on-line during that period. The only constraint on prices at such times, in a competitive unregulated market, is demand response. As prices rise, some customers would voluntarily reduce consumption rather than pay the higher price, thereby creating a sloping demand curve that crosses a vertical supply curve. This demand elasticity effectively closes the gap between the limited available supply and potential end-use demand. During such periods all units earn contributions to their fixed costs.

An important amendment to this exposition is required when a firm's opportunity cost of supplying to the market differs from its marginal production cost. Suppose, for example, that a small firm can sell into another geographical market or a subsequent downstream market, such as the ancillary services market, at a price sure to be higher than its marginal production cost. Then profit maximization dictates that the firm bid into the Day-Ahead Market at this higher price, which has become its opportunity cost of selling in the Day-ahead Market. Examples of such arbitrage have been observed in many instances between for example, electricity and gas markets. This behavior would set in motion the process of price arbitrage and the reallocation of resources between markets.

The above description fits a Generating Unit that can turn on and ramp up instantaneously and without cost, and that always runs at a constant thermal efficiency. Operators of such units can treat each hour independently. Most units have more complicated cost functions with inter-temporal effects and discrete costs for certain actions, so that their operators have to make plans across multiple hours. Typically, this is done with weekly or daily decisions by deploying a complicated process called "Unit Commitment", where a unit is optimally scheduled by taking into account unit commitment costs and various inter-temporal constraints.

We now discuss some of the resulting complications. **The biggest sources of complexity are startup costs, variable heat rates, and minimum loadings. These operating characteristics lead to non-convexities in the cost function where average variable costs can be above marginal cost**. To deal with startup costs and other non-convexities, operators make a unit commitment decision about which units to bring on-line. If a unit with a large startup cost (or a large gap between best and worst heat-rates) were called to generate for only a few hours during the week or during the day, it could cover its hourly marginal costs and yet still not earn enough to pay for startup costs plus the cost of running at minimum level during the hours it was not heavily loaded. A heuristic response to this problem would be to bid in this unit at a price somewhat higher than its marginal cost for each hour. This, however, is not profit-maximizing behavior for a perfect competitor.

A profit-maximizing perfect competitor would make decisions in two stages: the first stage is the unit commitment selection process and the second stage, given that the unit is on line, is the dispatch decision of the unit based on the bid prices set by the unit operator. At the start of each day, the operator would calculate the likely contribution margin (revenue minus variable costs, integrated over hours where price exceeds marginal cost) for the day, if the unit is bid in at marginal cost each hour. If this margin is greater than the startup costs plus low-load running costs, the operator would commit the unit. If the margin is less than those costs, the operator would not commit the unit. The operator would revisit the calculation each day using the latest forecasts of prices. Of course, this calculation should include all revenues from all markets, not just the Day-Ahead Market; once the unit is running, it provides a physical option that has value and can be sold as an Ancillary Service.

This unit-commitment logic implies that during weeks of low loads quite a few units may not be committed. Some would be undergoing seasonal maintenance, while others will not commit voluntarily. Therefore, even in low-load weeks prices would rise occasionally to at least the combustion-turbine level to induce participation of the gas turbines. If such prices were predicted for more than a few hours during the day, however, this would possibly persuade the operator of the next uncommitted steam unit to commit it for the next day. If prices behave unexpectedly during the day, suppliers could respond and change their unit commitment decisions in either direction, midway through the week. For example, if there are unplanned outages in a week where some units were not committed, that might provide sufficient expected profit to bring some other units on line midweek. If prices trend lower than expected during a week, an operator might decide to withdraw a unit early.

In the unit commitment process described above, price forecasts are very critical; but these forecasts are not perfect. Therefore when bidding the unit for Monday, the operator might choose to bid the unit even if it does not expect the unit to be called to generate. In this situation, and only in this situation (not currently planning to run that day), it would make sense to bid the unit at higher than the marginal fuel and operating and maintenance costs the generator would expect to incur if it had planned to run the unit. In this way the unit will be needed only if prices are higher than the operator's forecast. Note that despite non-convexities, once an operator has decided that a unit will be on-line the following day, the profit-maximizing bid (for a perfect competitor) is to bid the marginal cost in each hour, and to let the market decide when how much the unit will generate.

The above exposition gives credence to the claim that in essence the non-convexities are sunk costs for the day and should be ignored in setting the bids (in the second stage of the strategy of the profit-maximizing perfect competitor).

Substantial actual experience observed over many years has shown that if the effects of non-convexities are substantial, they will show up in unit commitment decisions (first stage of the strategy) by a perfect competitor, rather than in its bid prices.

Thus our benchmark for perfectly competitive behavior is that Producers will bid marginal costs for all Generating Units they control. When prices for a day are expected to be low they will not bring all units on line. Prices will sometimes rise above anyone's marginal cost; occasional high prices are not, by themselves, evidence of non-competitive behavior. The above analysis does not apply when a firm might behave if it is not a perfect competitor, but rather recognizes its ability to influence prices.

In any case the above analysis gives credence to the claim that the simple hourly Orders for generation and demand does not allow generating firms to obtain technical feasibility and ensure profitability for their generating units. The resolution of this complex problem requires the deployment of one of the following two solutions (or a combination of both):

- Implementation of several iterations that will allow the Participants to change their position to achieve feasibility (in the old market designs in the USA), or
- Deployment of more complex/block Orders to approximate the optimization of their "internal costs", i.e., inter-temporal constraints (currently deployed in EU).

In the following the second solution, implemented in several European markets, is further analyzed.

b. Block Orders

Most Power Exchanges in Europe allow Participants to submit, in addition to single or portfolio of Orders, combinatorial products called “Block Orders” that introduce inter-temporal constraints and mimic some of the unit technical (e.g. technical minimum) and operational constraints (e.g. fuel availability, especially for hydro units) and/or multi-period cost structures (start-up cost, shut-down cost, no-load or minimum-load cost). **Block Orders cannot be accepted for a volume less than their Minimum Acceptance Ratio. The Minimum Acceptance Ratio is the same for all Market Time Units in the Block Order.**

The Block Orders that are tradable in the Day-Ahead Markets comprise the following:

1. **User-defined Block Orders**: A user-defined Block Order consists of a fixed price limit (for selling or purchasing energy, respectively) and a fixed volume for a user-defined number of consecutive Market Time Units (block periods). Block Orders are accepted or rejected, depending on the average market clearing price along the block periods. Block Sell Orders are extremely helpful to portfolio managers with production assets, since they can spread out in many Market Time Units their units’ start-up and shut-down cost.

> ***Block Orders allow Participants achieve technical feasibility for their generation fleet but their presence complicates the electricity market clearing process.***

2. **Fixed Block Orders**: They are similar to the user-defined Block Orders mentioned above, except that the block periods (start, end) are pre-defined (by the Market Operator) and fixed. The definition of these blocks usually follows the system load curve (base, peak, off-peak) or it may follow a simple daily period slicing method (e.g. 00:00-06:00, 06:00-12:00, 12:00-18:00 and 18:00-24:00 or any other possible combination). The fixed Block Orders are similar in terms of simulation with the user-defined Block Orders.

3. **Linked Block Orders (LBO):** The clearing of these Orders is conditional and related to the clearing of their associated Block Order (called “parent block”). There are two possible relations between the “parent” and “child” block, (a) a tower-like parental relationship, and (b) a parallel parental relationship in each prioritization level, as shown in the *Figures 5-3* and *5-4*, respectively. The purpose of LBO is to help mainly Producers to schedule efficiently their Generating Units above their technical minimum.

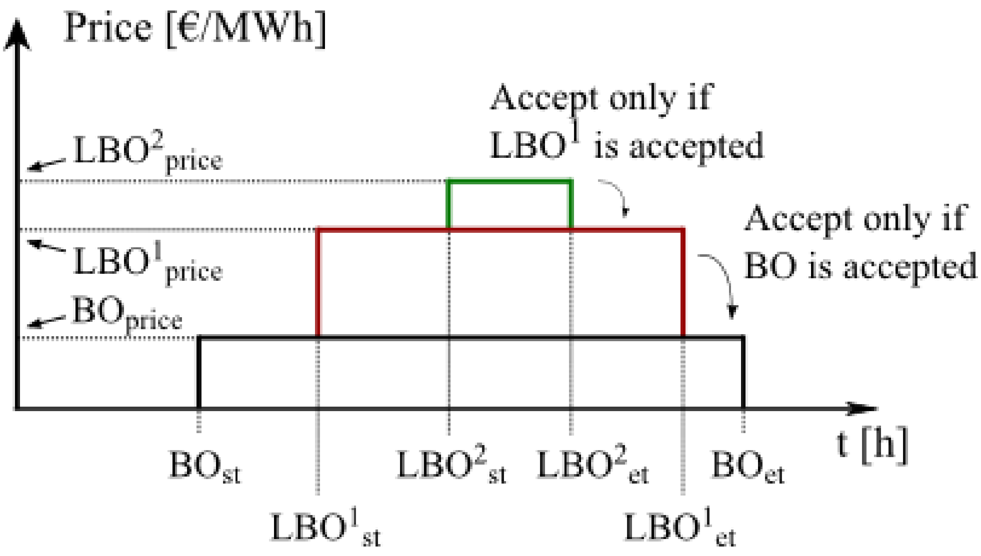

Figure 5-3: Tower-Like Parental Relationships

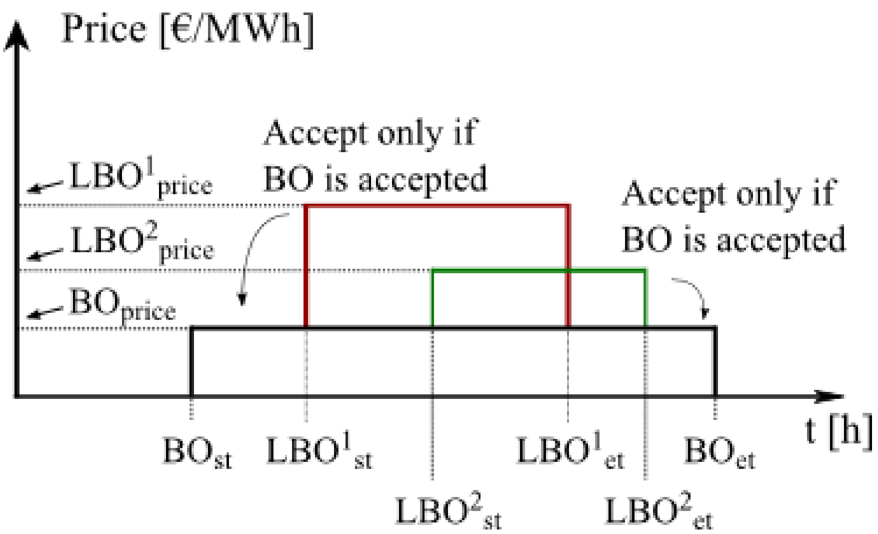

Figure 5-4: Parallel Parental Relationships in Each Prioritization Level

4. **Profile Block Orders**: A profile Block Order is similar with the simple Block Order, with the difference that it involves an energy profile during the subsequent Market Time Units, not a fixed energy quantity. The clearing of a profile block is based on the comparison between its Order price and the weighted average market clearing price for the specified set of Market Time Units. The purpose of Profile Block Orders is to help mainly Producers to schedule efficiently (using a certain production profile) their Generating Units above their technical minimum, using a Minimum Acceptance Ratio (corresponding to the technical minimum) and the offered quantity as the technical maximum of the Generating Unit.

   It is evident from the above that the Minimum Acceptance Ratio is a real number between a lower bound (e.g. 0.7) and a higher bound (usually equal to 1), and indicates the clearing level of the block.

5. **Exclusive group of Block Orders**: An "exclusive" group is a set of Block Orders for which the sum of the acceptance 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. Between the different valid combinations of accepted blocks, the algorithm chooses the one which maximizes the optimization criterion.

   The purpose of exclusive block Orders is to help mainly Producers to flexibly schedule their Generating Units within the daily period.

6. **Flexibly 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 Market Time Unit. The Market Time Unit is not defined by the Participant but will be determined by the algorithm (hence the name "flexible"). The Market Time Unit in which the Flexible Hourly Order is accepted is defined in the clearing results and is determined by the optimization criterion.

Table 5-1 summarizes the basic features of each type of Block Order.

No	Block Order Name	Description
1	User-defined Block Orders	Consists of a fixed price limit (for selling or purchasing energy, respectively) and a fixed volume for a user-defined number of consecutive Market Time Units.
2	Fixed Block Orders	Similar to the user-defined Block Orders mentioned above, except that the block periods (start, end) are pre-defined (by the Market Operator) and fixed.
3	Profile Block Orders	Similar with the simple Block Orders, with the difference that they involve an energy profile during the subsequent Market Time Units, not a fixed energy quantity.
4	Linked Block Orders	The clearing of these Orders is conditional and related to the clearing of their associated Block Order (called "parent block").
5	Exclusive group of Block Orders	An exclusive group is a set of Block Orders for which the sum of the accepted ratios is less than or equal to one. In case of blocks with a minimum acceptance ratio of one, at most only one of the blocks contained in the exclusive group can be accepted.
6	Flexible Hourly Orders	Cleared only on one Market Time Unit (typically hour) of the day; i.e. at the Market Time Unit that maximizes the social surplus.

Table 5-1: Types of Block Orders Tradable in the Greek Day-Ahead Market

The presence of Block Orders complicates the clearing of electricity auctions. In addition to constrained continuous variables for Simple Orders, a market clearing problem with blocks requires the inclusion of binary variables, in order to model "all-or-nothing" constraints of Block Orders. This leads to the formulation of Mixed-Integer Linear Programming (MILP) models. However, such formulations generally lead to inconsistencies between the cleared blocks and their clearing conditions. These cases have been referred many times as "**paradoxically accepted or rejected blocks**". These inconsistencies arise from the fact that blocks are indivisible (accepted or rejected in their entirety), so they cannot be marginal in the market clearing. Thus, the clearing of a block introduces a non-convexity in the solution space, and "price jumps" in the market prices for the block-related Market Time Units, when the block is marginally passing from an "accepted" to a "rejected" status and inversely.

Most Market Operators have historically adopted heuristic rules, iterative heuristic procedures and empirical simplifying criteria in order to handle the "paradoxically accepted or rejected blocks", reach a solution and obtain the clearing prices. An iterative process is used also by "Euphemia" (as described in Annex B), the Day-Ahead Market solver that is already used by the European PXs under the Multi-Regional Coupling (MRC) initiative.

c. *Simple Orders and Complex Orders (as in Spain)*

The types of Orders used in the Iberian Day-Ahead Market (Spain, Portugal) include even more complex bidding formats. Complex Sell Orders are those that incorporate complex sale terms and conditions and those which, in compliance with the simple Order requirements, also include one or some the following technical or economic conditions:

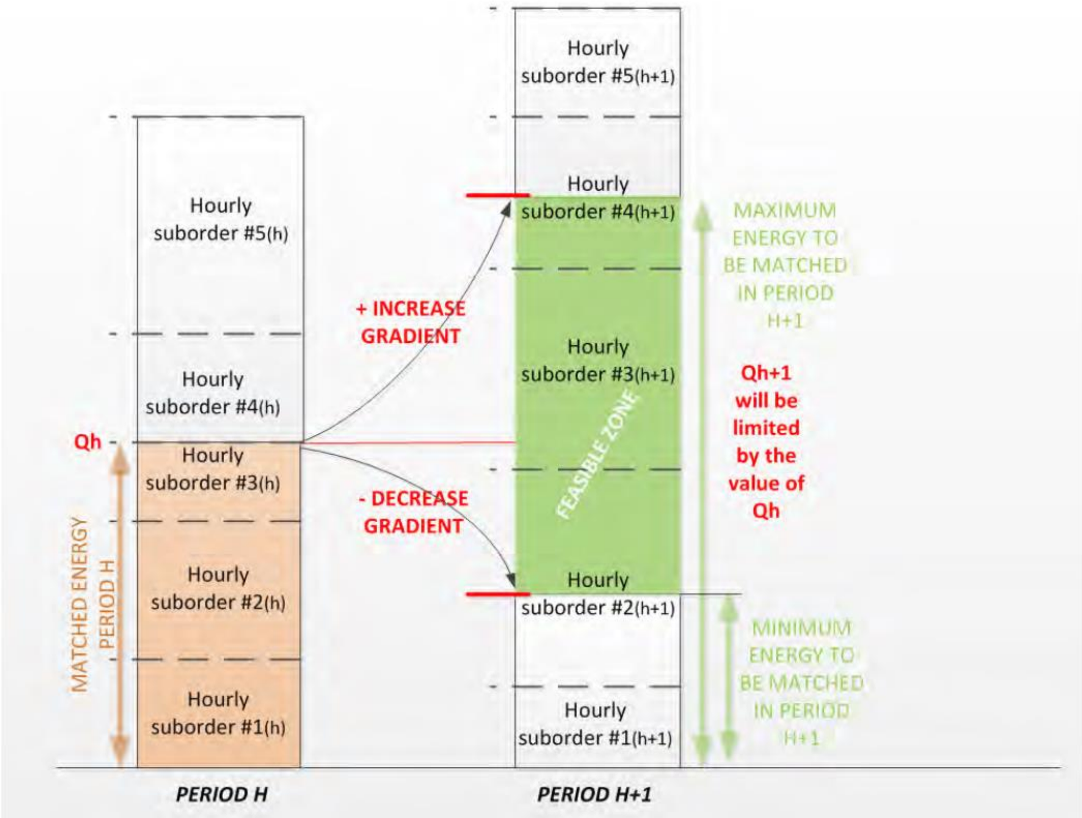

Figure 5-5: Load Gradient Orders

1. **<u>Load gradients</u>:** Complex Orders (with their set of hourly sub-Orders), on which a "load gradient" constraint applies, are called "load gradient Orders".

   Generally speaking, 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 (the same value for all periods). The Market Time Unit 1 is not constrained.

   This condition constitutes actually a maximum variation in output (in MW/minute, as a ramp rate) to ensure that matched output in consecutive Market Time Units is technically feasible.

2. **<u>Minimum income</u>**: Complex Orders (with their set of hourly sub-Orders) subject to "minimum income" condition constraints are called "minimum income condition" Orders (or MICs).

> ***Complex Orders allow Participants to cover their costs.***

Generally speaking, the "minimum income" economical constraint means that the amount of money collected by the Order in all periods must cover the Producer's production costs, which is defined by a fix term (representing the start-up 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).

The "minimum income condition" constraint is in short defined by:

- a fix term (in €), and
- a variable term (in € per accepted MWh).

In the final solution, MIC Orders are activated or deactivated (as a whole):

- In case a MIC Order is activated, each of the hourly sub-Orders of the MIC behaves like any other hourly Order, which means accepted if it is "in-the-money" and rejected if it is "out-of-the-money".
- In case a MIC Order is deactivated, each of the hourly sub-Orders of the MIC is fully rejected, even if it is "in-the-money" (with the exception of "scheduled stop", see below).

The final solution given by "Euphemia" will not contain active MIC orders not fulfilling their "minimum income condition" constraint (also known as paradoxically accepted MICs).

In essence, the MIC Order is cleared if its income level for the whole day is above an established fixed amount plus a variable payment for the cleared production quantity (in MWh).

3. **Scheduled stop:** In case the owner of a power plant which was running the previous day offers a MIC Order to the market, he may not want to have the production unit stopped abruptly in case the MIC is deactivated. This is activated when the "minimum income condition" is not fulfilled for the next day but the generator is scheduled to be producing in the last Market Time Unit of the current day. The generator has a maximum of 3 Market Time Units to stop producing on the next day (for which the "minimum income condition" was not fulfilled) so that it does not have to drop from full production at the end of one day to zero production at the start of the next day. The condition is implemented by accepting only the first step of the first 3 Market Time Units, as long as the production level decreases from Market Time Unit to Market Time Unit.

5.3 Pros and Cons of the Order Types

a. ***Producers:***

As mentioned and analyzed above, using Simple Orders it is difficult for Producers to attain feasible schedules for their Generating Units, due to the volatility of the DAM prices and the simplistic format of the Orders (lack of inter-temporal constraints, etc.). Thus, the more convenient options for Producers are (a) the Block Orders, and/or (b) the Complex Orders.

With respect to Block Offers we admit that it compromises the Bidding Zone price formation process in DAM (non-linear pricing) and may result in the need to introduce complementary market mechanisms or raise the re-dispatching costs at the ISP and Balancing Market. This is true in all markets worldwide where anything but simple Orders and no other non-convexities are part of the market problem formulation. This is a necessary condition to be able to implement a market design consistent with the constraints of the power system. Simplifications at many levels exist and have been implemented in various markets but the resulting market design deviates from actual operating conditions which creates its own more severe problems. Further analysis of this subject is outside the scope of this project. Euphemia has a specific way of handling these issues. Note, the in / out of the money Orders are analytically explained in Annex B of this report.

Their pros and cons are detailed below:

a) The Complex Orders (i.e. the “minimum income conditions”) have the advantage of covering both the fixed and variable cost of the Generating Units, but in case an order with a “minimum income condition” is accepted, it is not sure whether the cleared hourly quantities will result in a feasible schedule for the Generating Unit.

b) On the other hand, the Block Orders can always result in feasible schedules for the Generating Units (if they are appropriately submitted by the Producers), and they can be submitted with an offer price that can cover both the variable (operating) and fixed (start-up) cost of the Generating Unit, but this offer price is not so explicitly defined (variable plus fixed cost) as in Complex Orders. In case a Producer participates in the Forward/OTC Market, it is expected that, when submitting its Block Order in the Day-Ahead Market, it will take the Forward/OTC Contracts into account, in order to attain a feasible schedule for its Generating Units.

In all cases, if the portfolio management of the Producer fails to provide appropriate bidding for his Generating Units the following holds true:

a) in central-dispatch systems, the feasibility shall be enforced through the Integrated Scheduling Process run at the afternoon of day D-1, activating upward and/or downward balancing energy of the Generating Units; in central-dispatch systems, the Integrated Scheduling Process may even shut-down a Generating Unit which was “partially” scheduled in DAM, in case it is not competitive enough to cover the load and the system reserve requirements. **This fact puts the gas Producers at risk in terms of the flexibility allowed in their gas contracts**. Therefore, a close co-ordination of the gas providers and the Gas System Operator (DESFA) has been established, in order to allow more flexibility in the gas nominations of the producers within the day (currently there is possibility for 35 re-nominations during a gas day).

b) in self-dispatch systems, the Participant will be imbalanced, and he will be subject to the relative imbalance charges.

The above statements justify the clear superiority of Block Orders to attain feasible schedules for the Generating Units.

b. <u>Demand entities:</u>

Block Buy Orders are available in most European PXs for demand entities, which simulate technical constraints of the demand response facilities (most probably handled by an "aggregator"). These Block Buy Orders can be easily incorporated in the market framework and are already functional in "Euphemia" solver. So, when the necessary metering infrastructure is installed in end-consumers, potentially these Orders could be used for demand response purposes.

For the above reasons, simple hourly Orders and Block Orders shall be tradable for demand entities in the Greek Day-Ahead Market.

c. <u>RES Units and RES Portfolios:</u>

All types of Orders are available for all Participants. Nevertheless, RES Producers and RES Aggregators are not expected to submit Block Orders and Complex Orders, since the nature and design of such Orders fits only the conventional units, which have start-up costs, non-zero technical minimums and a significant variable cost. Simple hourly Orders are preferable also for non-controllable RES Units (e.g. wind plants, PV stations and small hydro units without a reservoir) and RES Portfolios, due to the variability and uncertainty of the production of these resources.

5.4 Orders Types in the Greek Day-Ahead Market

Considering the above analysis, **<u>the tradable Orders at the commencement of the Greek Day-Ahead Market shall be Simple Orders (step-wise and linear piecewise) and certain types of Block Orders</u>**. Additional types of orders may be introduced gradually as the market matures and the Market Operator gains more experience in managing these Orders.

The types of tradable Block Orders at the commencement of the Greek Day-Ahead Market shall be: fixed Block Orders, user-defined Block Orders and profile Block Orders. These Orders are particularly useful for Producers, so that they attain physically realizable schedules for their Generating Units.

At a second phase, linked Block Orders, exclusive groups of Block Orders and Flexible Hourly Orders can be included in the set of tradable Block Orders to provide additional options to the Participants.

It should be noted that currently the Block Orders are present only in wholesale electricity markets with portfolio-bidding. However, the structure of these Orders does not exclude the possibility to be applied also in unit-based markets. The minimum content of an Order submitted to the Trading Platform by a Participant shall be the following:

a) Participant EIC Code;

b) Entity EIC Code for which the Order is submitted;

c) Order type;

d) Sell Order or Buy Order;

e) Energy quantity and price for each step of a Step-wise Order or for each segment of a Linear piecewise Order or for each Block Order;

f) Market Time Unit(s) for which it is submitted; and

g) If applicable: any additional information as mandated by the Energy Trading System Rules or the prevailing functionality of the Trading Platform.

The Order prices are submitted in €/MWh with two (2) decimal places. The Order quantities are submitted in MWh with three (3) decimal places.

Each step-wise Order may include up to twenty (20) steps for each Market Time Unit.

Each linear piecewise Order may include up to twenty (20) segments for each Market Time Unit.

6 Day-Ahead Market Processes

6.1 Introduction

The Day-Ahead Market processes (pre-coupling, coupling and post-coupling operations) have been analytically discussed in *Chapter 2* of this report within the framework of the new market regime provisioned by the Target Model.

In *Chapter 5*, the proposed types of the Orders that will be submitted in the Greek Day-Ahead Market have been analyzed. The Sell/Buy Orders shall be submitted by the Producers per Generating Unit, by the RES Producers per Dispatchable and Non-Dispatchable RES Portfolio, by the RES Aggregators per Dispatchable and Non-Dispatchable RES Portfolio, by the Load Representatives per Dispatchable and Non-Dispatchable Load Portfolio and by the Traders, Suppliers and Self-Suppliers per interconnection and per direction. The format of the Sell/Buy Orders shall follow the format which is being described in *Section 5.4*.

The Buy Orders submitted by the Participants in the Day-Ahead Market shall be priced Orders, either with very high prices (price-taking Orders) or at competitive prices (price-making Orders) depending on the preference of the Participant.

Figure 6-1 illustrates the timeline for the Day-Ahead Market processes and the relevant information exchange between the Market Operator (Trading Platform), the TSO, the Participants (as Non-Clearing Members), the Clearing House and the Clearing Members.

Important note 1: Figure 6-1 does not include all information exchange between the Market Operator and the TSO during the pre-coupling and post-coupling operations, as described in Chapter 2, due to space limitations. The emphasis is given in this Figure in the information exchange between the Market Operator, the Clearing House, the Clearing Members and the Participants, and also between the TSO and the Participants. These elements are more important for the Participants, so that they comprehend better their obligations and the rules for participation in the Day-Ahead Market.

Important note 2: Figure 6-1 has been designed to present a contractual relationship between a Non-Clearing Member (which is implied as a Participant here) and a Clearing Member, which is supposed to be a financial institution (e.g. a commercial bank), registered with the Clearing House in order to provide services to the Participants. The case that a Participant is directly a Clearing Member constitutes a simplification of the above contractual relationship, and the respective information exchange (as in Figure 6-1) is straightforward.

Important note 3: Figure 6-1 presents the coupling operations in case of a normal process of Multi-Regional Coupling (MRC). In case of delays in the execution of the market coupling algorithm or in the publication of the results, respective delays shall take place in the post-coupling operations. Additionally, in case of partial- of full-decoupling of MRC, different processes shall be followed from 13:00 EET in day D-1 and onwards; such processes are described analytically in Chapter 9 of this report.

The obligations of the Participants as well as the information exchange between the stakeholders are further detailed in the following Sections of this Chapter.

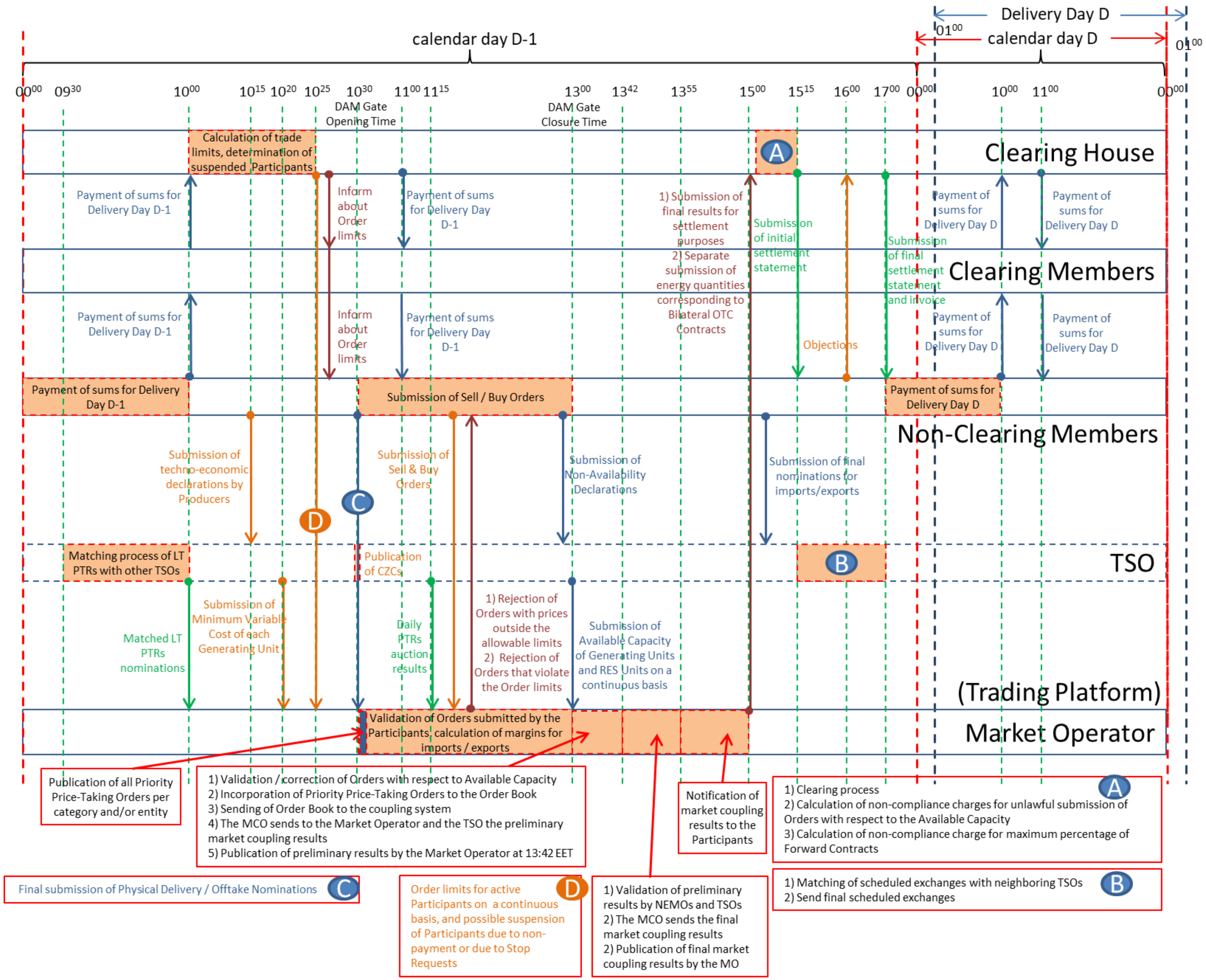

Figure 6-1: Timeline for the Day-Ahead Market processes and the relevant information exchange between the stakeholders (timing is in EET)

6.2 Information concerning Order Limits in the Greek Day-Ahead Market

Orders submitted by the Participants in the Trading Platform should comply with certain quantity and price restrictions. This Section presents both the quantity-based and the price-based limits that may be applied to the Participants.

6.2.1 Minimum and Maximum Order Price

The price of the Orders submitted by the Participants within the Day-Ahead Market shall be within an administratively defined range. More specifically, the Orders prices shall be greater than or equal to the Administratively Defined DAM Orders Lower Price and less than or equal to the Administratively Defined DAM Orders Upper Price. These two price limits shall be established by a relevant suggestion of the Market Operator which shall be approved by the enforcement of the above price limits.

6.2.2 Non-Availability Declaration

Producers and RES Producers must submit to the Transmission System Operator Total or Partial Non-availability Declarations for the Generating Units and RES Units respectively according to the provisions of the Balancing Market Code. RES Aggregators representing Dispatchable and/or Non-Dispatchable RES Portfolios are not required to submit Total or Partial Non-Availability Declarations.

A Total or Partial Non-Availability Declaration issued past the Day-Ahead Market Gate Closure Time for a Delivery Day for which Total or Partial Non-Availability is stated shall not entitle the Producer or the RES Producer to submit new Orders in the Day-Ahead Market. In this case, the updated Generating Unit or RES Unit Available Capacity shall be considered in the Intra-Day Market, in the Integrated Scheduling Process and in the Real-Time Balancing Market.

The most recent information submitted in the Total or Partial Non-Availability Declarations before the Day-Ahead Market Gate Closure Time determines the Available Capacity of Generating Units and RES Units.

The Transmission System Operator shall submit to the ETS, on a continuous basis upon receipt and acceptance of the Total or Partial Non-Availability Declaration of the Participant, the Available Capacity of the Generating Units and RES Units for the Delivery Day.

The last updated Available Capacity of Generating Units and RES Units is used by the

Market Operator for the validation process of the Day-Ahead Market Sell Orders

6.2.3 Minimum Variable Cost of Generating Units

The Minimum Variable Cost currently used for the validation of the Generating Units' Sell Orders prices in the Greek market is not applicable in most (or possibly all) European Day-Ahead Markets. **This constraint stems from the fact that the Greek electricity market is dominated by the incumbent, who owns the majority of generating units in Greece, and essentially all low-cost production units. The constraint has been applied in order to prevent the incumbent from exercising its market power and setting very low prices in the Day-Ahead Market.** Except from Greece and France, no other liberalized wholesale electricity market has similar characteristics. This is the reason that such constraint is not active in the European markets.

The pros and cons of this activity rules are the following:

Pros:

1) Undoubtedly this rule is the most important market power mitigation rule in the DAM market, given the current market conditions in Greece.

2) Mitigates the possible strategic bidding of the dominant participant ex-ante, which means that no ex-post monitoring process by the Market Operator and RAE is required. This is important given the burden that the ex-post monitoring process creates on the Market Operator Participants, depending on the specific conditions, may take months and may result in possible sanctions that can be challenged in a court of law.

3) The market is familiar with the application of this activity rule.

4) This rule allows for the enforcement of minimum Order prices for the hydro units, according to the new methodology applied in October 2016 [14].

5) It determines a predictable "minimum expected level of income" for the conventional thermal units.

6) It improves the price-discovery process in the DAM.

Cons:

[14] The methodology for calculating the minimum Order price for the hydro units is publicly available via the following link:
http://www.lagie.gr/fileadmin/groups/EDRETH/Hydro_Variable_Cost/RAE_207_2016.pdf

1) The activity rule is inflexible for the Participants.

2) It leads to more predictable DAM prices which can be manipulated by strategic bidding of Participants in neighboring bidding zones. For example, when a foreign producer knows that the price in a neighboring Bidding Zone is not expected to fall below e.g. 45 €/MWh, he may strategically increase his offers in order to take advantage of the expected price differential between his Bidding Zone and the neighboring Bidding Zone.

3) No other European country has a similar lower limit in the Sell Orders that are submitted by the Producers of Generating Units.

Alternatively, this activity rule can be relaxed, which means extensive ex-post monitoring procedures (by the Market Operator and RAE) need to be implemented and put in place from the commencement of the new market. In this case the reverse arguments can be made from the case above.

ECCO recommends to keep this activity rule active for a transition period of two (2) years. A simulation-based analysis tailored to the specific market and operational conditions in Greece is required to accurately determine the impact of this market activity rule on the market efficiency of the new market. Such a study is outside the scope of this project. It can be fully analyzed as an extension of the current project.

This administrative lower price for the priced Sell Orders of Generating Units is not directly connected or affected by the implementation of the Target Model in Greece, but it explicitly affects, as we discussed above, the trading performed in the interconnections. Specifically, the local IT system can implement this activity rule and the Sell Orders submitted to the MRC reflect the rule.

Implementation Details:

Important note 1: In order this validation check to be feasible by the Market Operator, the Participants must submit to the TSO Techno-Economic Declarations, according to the provisions of Section 8.5 of the Balancing Market detailed design document. Based on this information, the Transmission System Operator calculates the Minimum Variable Cost of each Generating Unit at the Generating Unit Meter Point for each Delivery Day, as defined in Chapter 6 of the Balancing Market Code. The Transmission System Operator shall inform the Market Operator concerning the Minimum Variable Cost of the Generating Units for each Delivery Day.

Important note 2: The above information exchange takes place before the gate open for the Day-Ahead Market Orders, so that the validation is executed on-the-fly (during the Orders' submission) by the Trading Platform. In case an Order passes the validation check, the Order is validated and inserted in the Local Order Book. Otherwise, the Order is automatically rejected by the Trading Platform, displaying a relevant rejection notification to the respective Participant.

6.2.4 Buy Order Financial Limits

According to the Day-Ahead Market Code provisions, the Clearing House shall set financial limits to its Clearing Members with regard to the Buy Orders of their Non-Clearing Members for participating in the Day-Ahead Market.

Clearing Members that provide financial settlement and coverage to Participants acting as Non-Clearing Members of the Clearing House, calculate and impose financial limits to the Participants with regard to the validation of the Participants’ Buy Orders submitted in the Day-Ahead Market. The Buy Order Limits shall be financial limits (cash limits), limiting the amount that will be paid by the Participant in case the submitted Buy Orders are accepted, depicting the maximum financial exposure up to which a Participant can buy energy from the Day-Ahead Market. Additionally, Participants may define more restricting Buy Order Financial Limits in order to proactively manage their risk exposure. In case such Buy Order Financial Limits entered by a Participant are more restricting than the respective limits enforced by its Clearing Member, then these more restricting limits shall apply.

Finally, the Clearing Members notify the Buy Order Financial Limits concerning each Non-Clearing Member to the Clearing House.

6.3 Day-Ahead Market Trading and Pre-Coupling Operations

6.3.1 Information Transfer from the Transmission System Operator to the Market Operator

The Transmission System Operator provides the following information to the Market Operator with respect to the operation of the Day-Ahead Market during calendar day D-1 for the Delivery Day D:

a) the information from the Balancing Market Registry for each Participant and for each Delivery Day D, until thirty (30) minutes before the Day-Ahead Market Gate Opening Time in day D-1;

b) the information from the Generating Unit Registry for each Generating Unit for each Delivery Day D, no later than thirty (30) minutes before the Day-Ahead Market Gate Opening Time in day D-1;

c) the nominated Long-Term Physical Transmission Rights (LT PTRs) of the Participants per border and per direction for each Market Time Unit of the Delivery

Day D, until thirty (30) minutes after the latest LT PTRs Nomination Gate Closure Time in day D-1;

d) the results of the daily auction for the allocation of Physical Transmission Rights at the non-coupled interconnections, until fifteen (15) minutes after the publication of the daily auction results to the Participants in day D-1;

e) the Available Capacity of each Generating Unit and each RES Unit for each Market Time Unit of the Delivery Day D, according to Section 6.2.2, on a continuous basis upon receipt and acceptance of the Total or Partial Non-Availability Declaration of the Participant; and

f) the Minimum Variable Cost of each Generating Unit for Delivery Day D, according to Section 6.2.3, until ten (10) minutes before the Day-Ahead Market Gate Opening Time in day D-1.

6.3.2 Information Transfer from the RES and CHP Units Registry Operator to the Market Operator

The RES and CHP Units Registry Operator provides to the Market Operator with respect to the operation of the Day-Ahead Market during calendar day D-1 for the Delivery Day D the information from the RES and CHP Units Registry for each RES Unit and CHP Unit and the relevant RES Aggregator Representation Declarations no later than thirty (30) minutes before the Day-Ahead Market Gate Opening Time at day D-1.

6.3.3 Priority Price-Taking Orders

The Priority Price-Taking Sell Orders are simple one-step Step-wise Sell Orders that are submitted with a price equal to the lowest acceptable price at the Day-Ahead Market, namely at the Administratively Defined DAM Orders Lower Price, minus a Priority Price Biasing Value. The Priority Price-Taking Buy Orders are simple one-step Step-wise Buy Orders that are submitted with a price equal to the highest acceptable price at the Day-Ahead Market, namely at the Administratively Defined DAM Orders Upper Price, plus a Priority Price Biasing Value.

The Transmission System Operator submits, on behalf of Participants, Priority Price-Taking Orders at the ETS of the Market Operator with respect to the Day-Ahead Market for each Market Time Unit of the Delivery Day D, as follows:

a) Priority Price-Taking Sell Orders for the scheduled production of Generating Units in Commissioning or Testing Operation and RES Units in Commissioning or Testing Operation;

b) Priority Price-Taking Sell Orders for the Mandatory Hydro Injections; and

c) Priority Price-Taking Buy Orders for the forecasted energy quantities of the Transmission System Losses

until the Day-Ahead Market Gate Opening Time in day D-1.

The Last Resort RES Aggregator submits Priority Price-Taking Sell Orders at the ETS of the Market Operator with respect to the Day-Ahead Market for each Market Time Unit of the Delivery Day D for the forecasted production of each represented RES Portfolio, until the Day-Ahead Market Gate Opening Time in day D-1.

The RES and CHP Units Registry Operator submits Priority Price-Taking Sell Orders at the ETS of the Market Operator with respect to the Day-Ahead Market for each Market Time Unit of the Delivery Day D for the following:

a) the forecasted production of each RES FiT Portfolio; and

b) the Priority Declarations of the High-Efficiency Cogeneration Dispatchable Units,

until the Day-Ahead Market Gate Opening Time in day D-1.

The Market Operator submits, on behalf of Participants, Priority Price-Taking Orders at the ETS of the Market Operator with respect to the Day-Ahead Market for each Market Time Unit of the Delivery Day D, as follows:

a) Priority Price-Taking Sell Orders for the energy quantities of the Exchange Based Forward Market that have been nominated in the Registration and Nomination Platform through validated Physical Delivery Nomination;

b) Priority Price-Taking Buy Orders for the energy quantities of the Exchange Based Forward Market that have been nominated in the Registration and Nomination Platform through validated Physical Offtake Nominations;

c)Priority Price-Taking Sell Orders for the energy quantities of Bilateral OTC Contracts that have been nominated in the Registration and Nomination Platform through validated Physical Delivery Nomination; and

d) Priority Price-Taking Buy Orders for the energy quantities of Bilateral OTC Contracts that have been nominated in the Registration and Nomination Platform through validated Physical Offtake Nominations;

until the Day-Ahead Market Gate Opening Time in day D-1.

6.3.4 Information Transfer from the Clearing House to the Market Operator

The Clearing House shall provide the following information to the Market Operator with respect to the operation of the Day-Ahead Market:

a) on a continuous basis the Buy Order Financial Limits of each non-suspended Participant; and

b) the list of suspended Participants, according to the relevant provisions of the Clearing House Rulebook, until five (5) minutes before the Day-Ahead Market Gate Opening Time in day D-1.

The latest updated data submitted by the Clearing House as per paragraph 1 is considered by the Market Operator in case of a failure in receiving the above information.

6.3.5 Information Transfer from the Coordinated Capacity Calculator to the Market Operator

The relevant Coordinated Capacity Calculator shall send to the Market Operator the Cross-Zonal Capacities and the Allocation Constraints no later than 12:00 EET in day D-1, according to paragraph 1 of Article 46 of the CACM Regulation.

In case the relevant Coordinated Capacity Calculator is unable to provide for Cross-Zonal Capacity and Allocation Constraints one hour prior to the Day-Ahead Market Gate Closure Time, the Coordinated Capacity Calculator shall notify the Market Operator, according to paragraph 2 of Article 46 of the CACM Regulation. The Market Operator shall immediately publish a notice for the Participants. In such cases, Cross-Zonal Capacity and Allocation Constraints shall be provided by the Coordinated Capacity Calculator no later than thirty (30) minutes before the Day-Ahead Market Gate Closure Time.

6.3.6 Calculation of Order Energy Quantity Margins

6.3.6.1 Imports and Exports for non-coupled Interconnections

Following the submission of the results of the daily auction for the allocation of Physical Transmission Rights at the non-coupled interconnections by the Transmission System Operator to the Market Operator, the Market Operator shall calculate the maximum energy quantities (i.e. margins) to be offered for imports and exports in all interconnections, as follows:

$$Margin_{p,i,h} = DailyPTRs_{p,j,h} + AvailForBid_{p,i,h} \qquad \forall\, p,i,h$$

where:

p	index of Participants
i	index of all interconnections
j	index of non-coupled interconnections, inclusive of the case of decoupling of coupled interconnections

h	index of Market Time Units
$DailyPTRs_{p,j,h}$	Daily PTRs acquired by Participant p for interconnection j for Market Time Unit h, in MW; the value of this parameter is equal to zero for all interconnections applying Market Coupling
$AvailForBid_{p,i,h}$	difference between the nominated long-term PTRs and the long-term PTRs used for the allocation of Forward Contracts with Physical Delivery Nominations and Physical Offtake Nominations, in MWh

Example:

Suppose a Participant A acquires 10 MW yearly PTRs and 5 MW monthly PTRs for month July, for imports in the interconnection FYROM-Greece. With regard to a certain day D of July and a certain Market Time Unit h, the Participant nominates the use of 12 MWh (out of the 15 MW long-term PTRs) until the long-term PTRs Nomination Gate Closure Time in day D-1, and declares until 10:00 EET D-1 that 9 MWh of these nominated imports shall be used to cover a bilateral OTC transaction for selling energy to another Participant B.

Suppose also, that the same Participant A acquires another 4 MW daily PTRs, from the respective daily auction, for imports in the interconnection FYROM-Greece.

In this context, the margin for the Participant's A import Offer to the Day-Ahead Market, with regard to the said trading hour and for the interconnection FYROM-Greece, should be set to:

$$Margin_{p,i,h} = DailyPTRs_{p,i,h} + AvailForBid_{p,i,h} = 4 + [12 - 9] = 7\ MWh$$

6.3.6.2 Generation Units

The Producers are obligated to offer the remaining of the Available Capacity of their Generating Units (what has not been already contracted in the Exchange Based Forward Market or through Bilateral OTC Contracts) in the Day-Ahead Market, in order to ensure the liquidity of the Day-Ahead Market and prevent physical withholding. Thus, there is no possibility for producers to "by-pass" the Day-Ahead Market and participate (to offer production availability) in the Intra-Day Market.

In this context, thirty minutes after the Physical Delivery Nomination Gate Closure Time the Market Operator shall calculate the maximum energy quantities (i.e. margins) to be offered in the Day-Ahead Market for each Generating Unit, as follows:

$$Margin_{i,h} = AvailCap_{i,h} - PDN_{i,h} \quad \forall\, i,h$$

where:

i	index of Generating Units
h	index of Market Time Units
$AvailCap_{i,h}$	Available Capacity of the Generating Unit *i* for Market Time Unit *h* in MW;
$PDN_{i,h}$	Validated Physical Delivery Nomination for Generating Unit *i* for Market Time Unit *h* in MWh.

The margins calculated by the Market Operator shall be used for the validation of the energy quantities of the Orders of the relevant Participants.

<u>Example:</u>

Suppose a Participant A owns a Generating Unit with a nominal capacity of 300 MW. For the month May, this Participant enters into a baseload Forward Transaction (in the Exchange Based Forward Market) to sell 120 MWh/hour.

Also, for a certain Delivery Day D of May, the said Participant enters into a Bilateral OTC transaction with another Participant B, to sell 12 MWh/hour for the whole day D. The Participant A declares by 10:00 EET in day D-1 the generating unit to cover both trades (forward & OTC).

For each Market Time Unit of this day D, the margin that should be set by the Market Operator for this generating unit for Day-Ahead Market Orders equals (300 – 120 – 12) MWh = 168 MWh.

<u>It should be noted that for hydro units with mandatory injections, this margin should be set for both the priced and "Priority Price-Taking" Sell Orders (if they have not been used previously to cover Forward Contracts) of these units.</u>

6.3.7 Day-Ahead Market Trading Days and Hours

Day-Ahead Market concerns wholesale trading on each calendar day D-1, where contracts for the supply of electricity are auctioned for each Market Time Unit of the Delivery Day D.

The Market Time Unit of the Day-Ahead Market is equal to one (1) hour.

The Delivery Day comprises of twenty-four (24) Market Time Units, starting at 01:00 EET on a calendar day, D and ending at 01:00 EET on the following calendar day, D+1. On the short-clock change day in March (beginning of summer savings time), there will be twenty-three (23) Market Time Units while on the long-clock change day in October (end of summer savings time), there will be twenty-five (25) Market Time Units.

The Day-Ahead Market Gate Opening Time for Delivery Day D shall be at 10:30 EET in day D-1, whereas the Day-Ahead Market Gate Closure Time shall be at 13:00 EET in day

D-1 for Delivery Day D. The Trading Platform shall not validate any Orders before the Day-Ahead Market Gate Opening Time.

The Market Operator shall be able to extend the Day-Ahead Market Gate Closure Time on any given day to the extent necessary, to maintain orderly trading conditions, for reasons related to full- or partial-decoupling.

6.3.8 Orders Submission, Validation and Correction Process

Participants that have been suspended by the Clearing House, due to non-payment of the due amounts or due to the enforcement of Stop Requests, according to the information provided by the Clearing House to the Market Operator as per Section 6.3.4, shall not be able to access the Trading Platform in order to submit Buy Orders at the Day-Ahead Market.

Participants shall submit their Orders and cancel or modify these Orders from the Day-Ahead Market Gate Opening Time until the Day-Ahead Market Gate Closure Time. The finally validated Orders that have been submitted lawfully shall be considered for inclusion in the Day-Ahead Market Local Order Book. The validated Orders included in the Day-Ahead Market Local Order Book are economically binding, meaning that in case of acceptance by the matching algorithm they shall be subject to a Financial Settlement.

The Trading Platform shall automatically reject a submitted Order by a Participant with respect to the Order price as follows:

a) when the Order price not corresponding to a Generating Unit is outside the range defined by the Administratively Defined DAM Orders Lower Price and the Administratively Defined DAM Orders Upper Price; and

b) when the Order price corresponding to a Generating Unit is outside the range defined by the Minimum Variable Cost of the Generating Unit for the Delivery Day and the Administratively Defined DAM Orders Upper Price.

In case of an automatic rejection of an Order, the Trading Platform shall automatically send to the respective Participant a rejection notice, including a justification for such rejection.

Furthermore, the Trading Platform shall automatically reject a submitted Buy Order by a Participant when the valuation of the Buy Order is higher than the respective Buy Order Financial Limit set as per Section 6.2.4. The valuation of the Buy Order is calculated as follows:

a) in case of step-wise Order it is equal to the sum over all steps of the Order step price multiplied by the Order step quantity.

b) in case of linear piece-wise Order it is equal the sum over all segments of the average Order segment price multiplied by the Order segment quantity.

c) in case of a Block Order it is equal to the sum over all Market Time Units the Block Order quantity multiplied by the Block Order price.

Finally, the Trading Platform shall automatically reject a submitted Order by a Participant with respect to the Order quantity as follows:

a) when the Sell Order quantity corresponding to energy injection for imports on a non-coupled interconnection is higher than the respective margin, computed as described in Section 6.3.6;

b) when the Buy Order quantity corresponding to energy withdrawal for exports on a non-coupled interconnection is higher than the respective margin, computed as described in Section 6.3.6; and

c) when the Sell Order quantity corresponding to energy injection for imports on an interconnection, submitted by a Self-Supplier, is higher than the sum of the Priority Price-Taking Buy Orders submitted on behalf of the Self-Supplier by the Market Operator as per Article 19 and the sum of the Buy Order quantities submitted by the Self-Supplier acting as Load Representative of its own Dispatchable and Non-Dispatchable Load Portfolios;

d) when the Sell Order quantity corresponding to energy injection of a Generating Unit or RES Unit violates the imposed respective margin of the Entity, as per Section 6.3.6.

e) when the Sell Order quantity corresponding to energy injection of a Dispatchable or Non-Dispatchable RES Portfolio violates the Registered Capacity of the Dispatchable or Non-Dispatchable RES Portfolio minus the Priority Price-Taking Sell Order, submitted on behalf of the RES Producer or RES Aggregator by the Market Operator.

f) when the Sell Order quantity corresponding to Physical Offtake Position Correction for a Dispatchable or Non-Dispatchable Load Portfolio, submitted by a Supplier or a Producer for the Auxiliary Load of a Generating Unit registered in the respective Participant Account, is higher than the Priority Price-Taking Buy Orders submitted on behalf of the Supplier or the Producer by the Market Operator;

g) when the Buy Order quantity corresponding to Physical Delivery Position Correction for a Generating Unit, RES Unit, Dispatchable or Non-Dispatchable RES Portfolio, submitted by the respective Participant, is higher than the Priority Price-Taking Sell Orders submitted on behalf of the Participant by the Market Operator;

On one hand, in case a Sell Order quantity corresponding to a Generating Unit plus the Priority Price-Taking Sell Order, submitted on behalf of the Producer by the Market Operator, are less than the Available Capacity of the Generating Unit, then the Market Operator shall impose non-compliance charges to the respective Producer, as described in Section 8.4. On the other hand, in case of a Buy Order corresponding to a Generating Unit, if the Priority Price-Taking Sell Order, submitted on behalf of the Producer by the Market Operator, minus the Buy Order quantity, is less than the Available Capacity of the Generating Unit, then the Market Operator shall impose non-compliance charges to the respective Producer, as described in Section 8.4.

6.3.9 Submission of Information from the Market Operator to the Market Coupling Operator

After the Day-Ahead Market Gate Closure Time the Market Operator processes and anonymizes the validated Orders in the Local Order Book in order to submit them to the Shared Order Book of the Market Coupling Operator.

Immediately after receiving the Cross Zonal Capacities and Allocation Constraints from the relevant Coordinated Capacity Calculator, the Market Operator submits the received data to the Market Coupling Operator.

The objective of the Day-Ahead Market clearing mechanism is the maximization of the sum of the surpluses of all Participants (representing supply and demand).

6.4 Market Clearing and Coupling Operations

6.4.1 Orders Matching

The Market Coupling Operator is responsible for the performance of the Market Coupling Operation Function. The Day-Ahead Market Coupling is based on a decentralized solution with a rotating operator being responsible for leading the Day-Ahead MCO Function procedures. Additionally, a rotating backup operator is appointed, which shall be able to take over the operator role in any process of the Market Coupling session. Details of the procedures performed by the operator and backup operator are included in the published MCO Plan[15].

The objective of the Day-Ahead Market Coupling mechanism is the maximization of the social welfare of the coupled European Day-Ahead Markets, namely the maximization of the sum of the surpluses of the Sell and Buy Orders included in the Shared Order Book plus the congestion rent. The surplus of the accepted Sell Orders equals the product of the difference of the Marginal Clearing Price minus their Order price and the accepted energy quantity. The surplus of the accepted Buy Orders equals the product of the difference of the Order price minus the Marginal Clearing Price and the accepted energy quantity.

The Day-Ahead Market problem constraints consist of the energy balance equation (i.e. the sum of accepted Sell Orders quantities is equal to the sum of accepted Buy Orders quantities) for each Market Time Unit of the Delivery Day, along with the acceptance rules

[15] The MCO Plan is publicly available via the following link:

http://www.europex.org/all-nemos/all-nemos-mco-plan/

of the validated Orders as described in the next sub-section, and any Cross-Zonal Capacity and Allocation Constraints.

The Day-Ahead Market matching engine handles the Paradoxically Accepted Sell and Buy Block Orders through an iterative process, at each iteration of which the intermediate solutions resulting in Paradoxically Accepted Sell and Buy Block Orders are effectively excluded from the binary tree defining the solution space. In the final solution, there are no Paradoxically Accepted Sell and Buy Orders.

6.4.2 Acceptance Rules of the Orders

This sub-section discusses briefly the clearing rules per type of tradable product in the Day-Ahead Market.

The acceptance rules of a Step-wise Sell Order are the following:

a) A step of the Order shall be totally accepted if its price is lower than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

b) A step of the Order shall be partially accepted if its price is equal to the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

c) A step of the Order shall not be accepted if its price is higher than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

The acceptance rules of a Step-wise Buy Order are the following:

a) A step of the Order shall be totally accepted if its price is higher than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

b) A step of the Order shall be partially accepted if its price is equal to the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

c)A step of the Order shall not be accepted if its price is lower than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

The acceptance rules of a linear piecewise Sell Order are the following:

a) A segment of the piecewise Order shall be totally accepted if its price at the right end of the segment is lower than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

b) A segment of the piecewise Order shall be partially accepted if its price at the left end of the segment is lower than the Market Clearing Price and its price at the right end of the piece is higher than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

c) A segment of the piecewise Order shall not be accepted if its price at the left end of the segment is higher than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

The acceptance rules of a linear piecewise Buy Order are the following:

a) A segment of the piecewise Order shall be totally accepted if its price at the right end of the segment is higher than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

b) A segment of the piecewise Order shall be partially accepted if its price at the left end of the segment is higher than the Market Clearing Price and its price at the right end of the segment is lower than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

c) A segment of the piecewise Order shall not be accepted if its price at the left end of the segment is lower than the Market Clearing Price of the Bidding Zone for the specific Market Time Unit of the Delivery Day.

The acceptance rules of a Sell Block Order are the following:

a) A Sell Block Order shall be accepted in its entirety (Acceptance Ratio equal to one) if the conditions (1) and (2) below are simultaneously valid:

   1) its price is lower than the weighted average Market Clearing Price for the Market Time Units of the Delivery Day involved in the Block Order (i.e. between the respective starting period and ending period), weighted by the respective accepted energy quantities of the Block Order; or

   2) during the matching process, this Block Order has not been identified as a Paradoxically Accepted Block.

b) A Sell Block Order shall be accepted in part (Acceptance Ratio between its Minimum Acceptance Ratio and one), if its price is exactly equal to the weighted average (weighted by the respective accepted energy quantities of the Block Order) Market Clearing Price for the Market Time Units of the Delivery Day involved in the Block Order. The Acceptance Ratio takes such value so that the weighted average Market Clearing Price between the starting Period and ending Period is equal to the Block Order price. In case it is partially accepted, a uniform loading factor is applied for the sold energy in all Market Time Units of the Delivery Day involved in the Block Order.

c) A Sell Block Order shall not be accepted (Acceptance Ratio equal to zero) if one of the following two cases applies:

   1) if its price is higher than the weighted average Market Clearing Price for the Market Time Units of the Delivery Day involved in the Block Order; or

   2) if its price is lower than the weighted average Market Clearing Price for the Market Time Units of the Delivery Day involved in the Block Order, but during the

matching process this Block Order has been identified as a Paradoxically Accepted Block.

In all cases, the accepted energy quantity of a Block Order for each Market Time Unit of the Delivery Day involved in the Block Order shall be equal to the Acceptance Ratio times the offered energy quantity of the Block Order.

The acceptance rules of a Buy Block Order are similar to the respective acceptance rules of a Sell Block Order, with the difference that the Buy Block Order is cleared when its price is higher – rather than lower – than the weighted average Market Clearing Price for the Market Time Units of the Delivery Day involved in the Buy Block Order, weighted by the respective accepted energy quantities of the Buy Block Order.

6.4.3 Day-Ahead Market Results

The Day-Ahead Market Coupling Results constitute the Market Clearing Prices per Market Time Unit of the Delivery Day and per Bidding Zone and the Net Delivery Position of each Bidding Zone.

The Day-Ahead Market Results constitute the Market Clearing Prices per Market Time Unit of the Delivery Day and per Bidding Zone and the accepted energy quantities of the Step-wise Orders, the linear piecewise Orders and the acceptance status of the Block Orders. All accepted Orders shall be settled at the Market Clearing Price.

All Priority Price-Taking Buy Orders are cleared, provided that the sum of energy quantities of the submitted Sell Orders is higher than or equal to the sum of energy quantities of the submitted Priority Price-Taking Buy Orders. In case that the sum of energy quantities of the submitted Sell Orders is less than the sum of energy quantities of the submitted Priority Price-Taking Buy Orders, the latter are partially cleared, the clearing ratio being equal for all Priority Price-Taking Buy Orders.

6.5 Post-Coupling Operations

6.5.1 Actions of the Market Operator and the Transmission System Operator concerning Day-Ahead Market Results

After the completion of the matching process, the Market Coupling Operator shall deliver the Preliminary Market Coupling Results to the Market Operator and to the Transmission System Operator until 13:42 EET in day D-1, according to Article 48 of the CACM Regulation and the MRC exact timeline. The Preliminary Market Coupling Results comprise Market Clearing Prices per Bidding Zone and accepted energy volumes within and between Bidding Zones.

Then, the Market Operator shall verify that the Day-Ahead Market Coupling Results of the Price Coupling Algorithm have been calculated in accordance with the Orders. In addition, the Transmission System Operator shall verify that the Day-Ahead Market Coupling Results of the Price Coupling Algorithm have been calculated in accordance with the Allocation Constraints and validated Cross-Zonal Capacity.

If the validation is positive then the Market Operator and the Transmission System Operator send a confirmation to the Market Coupling Operator. In case no Nominated Electricity Market Operator of the coupled markets rejects the Preliminary Market Coupling Results or triggers a Second Auction, the Market Coupling Operator shall deliver the Final Market Coupling Results to the Market Operator and to the Transmission System Operator until 13:55 EET in day D-1.

Afterwards, the Market Operator shall publish the Final Market Coupling Results until 13:55 EET in day D-1.

It should be noted that in emergency situations related to delays in performing the above tasks fallback procedures commence, as described in Chapter 9 of this report.

Finally, the Market Operator shall inform the Participants concerning the execution status of their Orders until 15:00 EET in day D-1 and no later than five (5) minutes after the notification of the Day-Ahead Market Results to the Participants, the Market Operator shall send the Day-Ahead Market Results to the Clearing House for Clearing and Settlement.

6.5.2 Actions of the Clearing House

The Clearing House shall:

a) calculate the Credits and Debits of Participants arising from their participation in the Day-Ahead Market.

b) compute the non-compliance charge for unlawful submission of Sell Orders with respect to the Available Capacity.

c) compute the non-compliance charge for violating the maximum percentage of Forward Contracts limitation.

d) perform the Settlement of the amounts with the Clearing Members of the Participants, applying any possible netting of Credits and Debits.

e) perform the Settlement of the amounts relative to the valuation of the Scheduled Energy Exchanges of the coupled interconnections.

7 Interface of the Day-Ahead Market with the Intra-Day Market

The information that should be transferred from the Day-Ahead Market to the Intra-Day Market for each Market Time Unit comprises of the following:

D1: The already matched Scheduled Exchanges (imports/exports) on each interconnection. These Scheduled Exchanges should be submitted to the TSOs, in order to compute the Cross Zonal Capacity left unused after the Day-Ahead Market solution. This Cross Zonal Capacity will be eligible to be used in the Intra-Day Market trading processes.

D2: The Market Schedule (Net Position) of each Generating Unit or Generating Unit in Commissioning or Testing Operation, namely the energy schedule resulting from the Day-Ahead Market solution. This shall be used in conjunction with the intra-day traded energy quantities as the starting point (initial position) for each subsequent solution of the Integrated Scheduling Process problem. Note that, the energy schedule "coming" from the Day-Ahead Market for each Generating Unit, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and bilateral OTC Markets by the corresponding Participant, allocated (declared) to the Generating Unit by the Participant at the Registration and Nomination Platform (by 10:00 D-1), and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market's clearing process by the Market Operator on behalf of the Generating Unit and by the TSO on behalf of the Generating Unit in Commissioning or Testing Operation during the pre-coupling operations. That is essentially the interface of the Forward and OTC Market processes with all intra-day processes following the Day-Ahead Market's solution.

D3: The Market Schedule (Net Position) of each RES Unit in Commissioning or Testing Operation, namely the energy schedule resulting from the Day-Ahead Market solution. This shall be used along with the energy bought/sold in the Intra-Day Market, in order to compute the RES Units' Net Position and which shall be used as input data in each subsequent solution of the Integrated Scheduling Process problem. Note that, the energy schedule "coming" from the Day-Ahead Market for each RES Unit in Commissioning or Testing Operation, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and bilateral OTC Markets by the corresponding Participant, allocated (declared) to the RES Unit in Commissioning or Testing Operation by the Participant at the Registration and Nomination Platform (by 10:00 D-1), and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market's clearing process by the Transmission System Operator during the pre-coupling operations.

D4: The Net Position of each Non-Dispatchable RES Portfolio in each Bidding Zone, which shall be used along with the energy bought/sold in the Intra-Day Market, in order to compute the RES imbalances that shall be inserted in each subsequent solution of the Integrated Scheduling Process problem. Note again that, the energy schedule "coming" from the Day-Ahead Market for this Entity, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and Bilateral OTC Markets by the corresponding Participant, allocated (declared) per Bidding Zone by the Participant at the Registration and Nomination Platform (by 10:00 D-1) and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market by the Last Resort Aggregator on behalf of the Non-Dispatchable RES Portfolio during the pre-coupling operations.

D5: The Net Position of each Dispatchable RES Portfolio in each Bidding Zone, which shall be used along with the energy bought/sold in the Intra-Day Market as input data in each subsequent solution of the Integrated Scheduling Process problem. Note again that, the energy schedule "coming" from the Day-Ahead Market for this Entity, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and Bilateral OTC Markets by the corresponding Participant, allocated (declared) per Bidding Zone by the Participant at the Registration and Nomination Platform (by 10:00 D-1) and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market by the Last Resort Aggregator on behalf of the Dispatchable Load Portfolio during the pre-coupling operations.

D6: The Net Position of each Non-Dispatchable Load Portfolio in each Bidding Zone, which shall be used along with the energy bought/sold in the Intra-Day Market, in order to compute the load imbalances that shall be inserted in each subsequent solution of the Integrated Scheduling Process problem. Note again that, the energy schedule "coming" from the Day-Ahead Market for each demand entity, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and Bilateral OTC Markets by the corresponding Participant, allocated (declared) per Bidding Zone by the Participant at the Registration and Nomination Platform (by 10:00 D-1) and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market by the Market Operator on behalf of the Non-Dispatchable Load Portfolio during the pre-coupling operations.

D7: The Net Position of each Dispatchable Load Portfolio in each Bidding Zone, which shall be used along with the energy bought/sold in the Intra-Day Market as input data in each subsequent solution of the Integrated Scheduling Process problem. Note again that, the energy schedule "coming" from the Day-Ahead Market for each demand entity, includes also the Exchange Based Forward and OTC quantities, which may have been traded in the Exchange Based Forward and Bilateral OTC Markets by the corresponding Participant, allocated (declared) per Bidding Zone by the Participant at the Registration and Nomination Platform (by 10:00 D-1) and inserted as "Priority Price-Taking" Orders (Orders with priority in market clearing) in the Day-Ahead Market by the Market Operator on behalf of the Dispatchable Load Portfolio during the pre-coupling operations.

D8: The Net Position of the RES FiT Portfolio in each Bidding Zone, which shall be used along with the energy bought/sold in the Intra-Day Market, in order to compute the RES FiT Portfolio injection imbalances that shall be inserted in each subsequent solution of the Integrated Scheduling Process problem.

8 Day-Ahead Market Settlements

8.1 Introduction

The trading process and the Clearing and Settlement process are highly interrelated but they will be performed by two separate companies, the Market Operator and the Clearing House. A new figure has been included in this report to highlight the information exchange between the Market Operator, the Clearing House, the TSO and the Participants in the Day-Ahead Market.

The Clearing House has, among others, the following responsibilities with respect to the Day-Ahead Market:

1) the determination of the Buy Order Financial Limits of each Participant in order to validate the Buy Orders at the Day-Ahead Market;

2) the calculation of the margin requirements of each Clearing Member; and

3) the Clearing, Settlement, invoicing and cash transfer of the Day-Ahead Market trades.

<u>**More specifically, no later than five (5) minutes after the notification of the Day-Ahead Market results to the Participants, the Market Operator shall send to the Clearing House the cleared energy quantities per Order and prices per bidding zone, so that the Clearing House is able to calculate for each Participant the sums of the Debits and Credits corresponding to them, in accordance with the cleared Sell Orders and Buy Orders.**</u>

Participants are required to pay to the Clearing House the sum calculated through the Day-Ahead Market Settlement and which corresponds to the accepted Buy Orders that are included in the Day-Ahead Market results. The Participants with accepted Sell Orders are entitled to collect from the Clearing House the sum calculated through the Day-Ahead Market Settlement and which corresponds to the accepted Sell Orders that are included in the Day-Ahead Market results.

In the following sub-sections the interface of the Clearing House with the Trading Platform of the Market Operator is described in detail.

8.2 Calculation of credits

The sums corresponding to payments shall be calculated daily for each Participant based on the accepted Sell Orders and the Day-Ahead Market results referring to the Delivery Day for such Orders. The Day-Ahead Market payments and collections are algebraic, i.e., payments are credits if positive, or debits if negative.

Any Participant submitting an Sell Order which is partially or wholly accepted at the Day-Ahead Market or any Participant for which the Market Operator submitted on its behalf a Priority Price-Taking Sell Order and it is accepted at the Day-Ahead Market Results shall be credited for such Order and for each Market Time Unit the sum resulting from the pricing at the Market Clearing Price of the accepted energy quantity of the Sell Order. The credit to Participant *p* for the accepted Sell Order *o* is calculated for the Market Time Unit *t*, as follows:

$$DAER_{p,o,t} = DAMCP_{z,t} \cdot DAIO_{p,o,t}$$

where:

$DAER_{p,o,t}$ the credit to which a Participant *p* is entitled for the accepted Sell Order *o* (which was submitted in Bidding Zone *z*) for Market Time Unit *t*, in €;

$DAMCP_{z,t}$ the Market Clearing Price in Bidding Zone *z* for Market Time Unit *t*, in €/MWh;

$DAIO_{p,o,t}$ the accepted energy quantity of Sell Order *o* (excluding the accepted energy quantity corresponding to Bilateral OTC Contracts) which corresponds to Participant *p* for Market Time Unit *t*, in MWh.

Priority Price-Taking Orders, submitted by the Market Operator for the energy quantities of Bilateral OTC Contracts that have been nominated in the Registration and Nomination Platform through validated Physical Delivery Nomination, are not assessed any Credit in the Day-Ahead Market Clearing process,

The daily Credit to a Participant *p* for all accepted Sell Orders *o* for the Delivery Day *d* is calculated as follows:

$$DAER_p = \sum_{teT} \sum_{o} DAER_{p,o,t}$$

For each Participant the total Credit for all its Sell Orders accepted at the Day-Ahead Market for all Delivery Periods of the Delivery Day is debited to the DAM Settlement Account A-A and credited to the Participant's Market Account.

8.3 Calculation of debits

The Debits shall be calculated daily for each Participant based on the accepted Buy Orders and the Day-Ahead Market Results referring to the Delivery Day for such Orders.

Any Participant submitting a Buy Order which is partially or wholly accepted at the Day-Ahead Market shall be debited for each Market Time Unit the sum resulting from the pricing at the Market Clearing Price of the accepted energy quantity of the Buy Order. The

Debit to Participant *p* for an accepted Buy Order *b* for a Market Time Unit *t* shall be calculated as follows (Note, Loads will pay the zonal price):

$$DAEP_{p,b,t} = DAMCP_{z,t} \cdot DAOD_{p,b,t}$$

where:

$DAEP_{p,b,t}$ the Debit to a Participant *p* for an accepted Buy Order *b* (which was submitted in Bidding Zone *z*) for the Market Time Unit *t*, in €;

$DAMCP_{z,t}$ the Market Clearing Price in Bidding Zone *z* for Market Time Unit *t*, in €/MWh; and

$DAOD_{p,b,t}$ the accepted energy quantity from Buy Order *b* (excluding the accepted energy quantity corresponding to Bilateral OTC Contracts) which corresponds to Participant *p* for Market Time Unit *t*, in MWh.

Priority Price-Taking Orders, submitted by the Market Operator for the energy quantities of Bilateral OTC Contracts that have been nominated in the Registration and Nomination Platform through validated Physical Offtake Nomination, are not assessed any Debit in the Day-Ahead Market Clearing process,

The daily Debit to a Participant *p* for all accepted Buy Orders *b* for the Delivery Day *d* is calculated as follows:

$$DAEP_p = \sum_{t \in T} \sum_{b} DAEP_{p,b,t}$$

For each Participant the total debit for all its Buy Orders accepted at the Day-Ahead Market for all Delivery Periods of the Delivery Day is credited to the DAM Settlement Account A-A and debited to the Participant's Market Account.

8.4 Non-compliance charge for unlawful submission of Sell Orders with respect to the Available Capacity

In case of unlawful submission of Sell Orders for a Delivery Day d for a generation resource u registered to Participant p obligated to such submission covering the Available Capacity, the Clearing House shall charge such Participant for such Delivery Day the sum of $NCEO_{p,d}$, as follows:

$$NCEO_{p,d} = UNCEO \cdot (1 + A_{EO}) \cdot \left(NEO_p\right)^x \cdot \sum_{u \in p} NCAP_u$$

where:

$UNCEO$ the unit charge for non-compliance charges to Participants for failing to submit valid Sell Orders for their generation resources by the Day-Ahead Market Gate Closure Time, in €/MWh;

A_{EO} the charge increase factor for non-compliance charges to Participants for failing to submit valid Sell Orders for their generation resources by the Day-Ahead Market Gate Closure Time;

NEO_p a running counter of the Delivery Days in the current calendar year when a Participant p failed to submit valid Sell Orders for its generation resources by the Day-Ahead Market Gate Closure Time;

x an exponent factor between 0 and 1,; and

$NCAP_u$ the Registered Capacity of generation resource u (in accordance with its Registered Operating Characteristics) for which Participant p has not lawfully submitted Sell Orders for Delivery Day.. d , in MW. In case of lawful submission of Sell Orders for a generation resource u for Delivery Day d, $NCAP_u$ in this equation shall be equal to zero.

The numerical values of the unit charge $UNCEO$, the exponent factor x and the charge increase factor A_{EO} shall be established for each calendar year by proposal of the Market Operator which shall be approved by the Regulator. Such decision shall be taken at least two months prior to the end of a calendar year, it shall be in force for the next calendar year and it cannot be modified within such year.

This charge is debited to the relevant Participant Market Account and credited to the Non-Compliance Charges Account A-C.

8.5 Maximum percentage of Forward Contracts

According to Article 14 paragraph 6 of Law 4425/2016, in order to secure the liquidity of the Day-Ahead Market (and the price discovery process), a maximum percentage of forward contracted quantities to cover a demand portfolio can be imposed to Load Representatives with significant retail market shares. This provision is crucial in order to secure the smooth transition of the current market structure to a market where more participants are vertically-integrated and participate with significant portfolios in the wholesale and retail market in Greece.

This rule shall be applied for a transitory period, and can be relaxed over time if the market conditions change. A roadmap shall be constructed by RAE indicating the status of the market or in other terms the pre-conditions under which these decisions will be taken/activated.

This rule will not allow the incumbent to clear most of its load requirements in the bilateral contracts (Forward/OTC) market, for example clear with bilateral contracts 80% or 90% of its represented demand, and bid only for the remaining load in the DAM. If such constraint is not applied, the price discovery process may be compromised since:

- The liquidity of the DAM would be significantly constrained, and
- The attained market prices would not express the short-term marginal cost of the electricity produced.

The above rule shall be imposed to the incumbent and all Load Representatives that gradually attain a market share of end-consumption above a regulatory defined percentage X%. The regulatory decision concerning the X% shall be taken on annual basis, until 31st October of the previous year Y-1 of the year of activation Y, based on a respective proposal by the Market Operator.

8.5.1 Computation of Maximum Threshold per Load Representative

The submission of Physical Offtake Nominations (to the Registration and Nomination Platform) has been described by Load Representatives for each Delivery Period of each Delivery Day D. The sum of Physical Offtake Nominations over all Bidding Zones *z* shall serve as the basis for the compliance check with the maximum percentage of forward contracted quantities of Load Representatives (demand side constraint).

The compliance check shall be applied on each day D-1 (for the energy schedules of Delivery Day D) after the DAM clearing (ex-post check), namely until 15.05-15.15 EET of day D-1 with regard to each Market Time Unit of Delivery Day D, based on the sum of Physical Offtake Nominations of said Load Representative *p* and the accepted buying quantities that have resulted from the Load Representative's bidding in the DAM. In this case, the compliance check shall be:

$$\frac{\sum_{z} PON_{z,p,t}}{\sum_{z}\left(PON_{z,p,t} + Y_{z,p,t}\right)} \leq A\% \qquad \forall\ t \in Delivery\ Day\ D,\ p \in Load\ Representatives$$

where:

$PON_{z,p,t}$	the Physical Offtake Nomination submitted by Load Representative *p* for Market Time Unit *t* of the Delivery Day D in Bidding Zone *z*,
$Y_{z,p,t}$	the accepted energy quantities of the Load Representative *p* in the Day-Ahead Market for Market Time Unit *t* of the Delivery Day D.
A%	the applicable maximum threshold of the above-mentioned constraint.

8.5.2 Penalties for Non-Compliance

Penalties for each Market Time Unit shall be imposed to the Load Representatives that do not comply with the criterion, with regard to the quantities that exceed the maximum threshold defined in the previous paragraph, and only for the Market Time Units that the above ratio overcomes the maximum threshold. The penalties should be high enough to avert the Load Representatives from employing strategic gaming with this constraint. The non-compliance charge is calculated for Market Time Unit *t* of the Delivery Day as follows:

$$NCC_{p,t} = \max\left(\left[\sum_{z} PON_{z,p,t} - A\% \cdot \sum_{z}\left(PON_{z,p,t} + Y_{z,p,t}\right)\right] \cdot CAP\ ,\ 0\right)$$

where:

CAP the Administratively Defined DAM Orders Upper Limit.

This charge is summed over all Market Time Units of a given month and it is debited to the relevant Participant Market Account and credited to the Non-Compliance Charges Account A-C.

8.6 Day-Ahead Market settlement procedure

The Day-Ahead Market Settlement shall be performed on a daily basis and shall include the following stages:

a) once the Credits and Debits, including the Debits of non-compliance charges, to each Participant have been calculated, the Clearing House shall record such sums separately for each Participant in the Initial DAM Settlement Statement. This Statement that is associated with each Participant will be communicated to Participants until 15:15 EET in day D-1;

b) no later than 16:00 EET in day D-1, the Participants are entitled to lodge documented objections to the Clearing House;

c) no later than 16:30 EET in day D-1, the Clearing House shall decide on any objections, finalize the debits and credits to each Participant and enter such sums separately for each Participant in the Final DAM Settlement Statement. The Final DAM Statement will be communicated to Participants with respect of the part concerning each one of them.

Both the Initial DAM Settlement Statement and the Final DAM Settlement Statement shall refer to one Delivery Day and include the following information:

a) the Participant name and EIC Code;

b) the energy quantities sold at the Day-Ahead Market per Market Time Unit;

c) the energy quantities purchased from the Day-Ahead Market per Market Time Unit;

d) the Market Clearing Price per Bidding Zone and per Market Time Unit;

e) the total amount owed by the Clearing House to the Participant for the sold Energy quantities at the Day-Ahead Market, separately for each priced and Priority Price-Taking Sell Order for each Market Time Unit of the Delivery Day in question, as well as the total sum of the payment for such Delivery Day;

f) the total amount owed by the Participant to the Clearing House for the purchased Energy quantities from the Day-Ahead Market, separately for each priced and Priority Price-Taking Buy Order for each Market Time Unit of the Delivery Day in question, as well as the total sum of the charges for such Delivery Day;

g) the amount owed by the Participant to the Clearing House due to the enforcement of the non-compliance charge for unlawful submission of Orders with respect to the Available Capacity, as per Section 6.2.2 of this report;

h) the amount owed by the Participant to the Clearing House due to the enforcement of the non-compliance charge for violating the maximum percentage of Forward Contracts, as per Section 8.5.2 of this report;

i) the amount owed by the Participant to the Market Operator and the Clearing House for the Day-Ahead Market Trading and Clearing Fees according to the applicable rates; and

j) any other information concerning the activities of each Participant that have been used in the above calculations.

The Final DAM Settlement Statement is followed by a relative Day-Ahead Market Settlement and Invoicing Statement and a respective invoice for the payments of the Participants to the Clearing House, whereas the invoice of the Participants to the Clearing House are issued and sent electronically by the Participants at the afternoon of day D-1 until 17:00 EET.

With respect to gate closures, every attempt is made to be fully consistent with EU practices. For example, EEC settles everything that is available before 16:00 CET (17:00 EET) at the same day, otherwise it is settled at the next Business Day. In our design all clearing / settlement / invoicing activities are completed till 17:00 EET. So, we think that we are fully aligned with European common practices.

Due payments of the Participants for the Day-Ahead Market Settlement and Invoicing Statements are effectuated via wired bank transactions at the indicated Due Date and Time which is set for next Bank Working Day at 10:00 EET of the Delivery Day while due payments of the Clearing House for the Day-Ahead Market Settlement and Invoicing Statements are effectuated via wired bank transactions at the indicated Due Date and Time which is set for next Bank Working Day at 11:00 EET of the Delivery Day..

9 Fallback procedures

9.1 General provisions

According to Article 50 of the CACM Regulation, in the event that all NEMOs performing MCO Functions are unable to deliver part or all of the results of the price coupling algorithm by the determined time (13:55 EET), fallback procedures established in each Capacity Calculation Region according to Article 44 of the CACM Regulation shall be initiated.

The fallback procedures comprise two main cases as follows:

1) Partial Decoupling

2) Full Decoupling

1) A Partial Decoupling is a situation where it is possible, for a specific day, to allocate CZCs through an implicit allocation process for one or several but not for all Bidding Zones and/or interconnectors before the relevant Partial Decoupling deadline is reached. In other words, the Partial Decoupling term is used to describe a decoupling of one or more Bidding Areas and interconnectors, thus allowing other Bidding Areas and interconnectors to remain coupled.

2) On the other hand, a Full Decoupling corresponds to a situation where it is not possible for a specific day, to allocate the CZCs through an implicit allocation process because the Full Decoupling deadline has been reached without having Market Coupling Results confirmed by the competent validating parties during the final confirmation process.

Under normal process, the regular publication time of the Preliminary Market Coupling Results is 13:42 EET. These Preliminary Market Results are subject to a final round of validation by the coupled parties and could be cancelled if one party rejects the Preliminary Results. If the Preliminary Market Coupling Results are not available at 13:42 EET, a delay message shall be sent out to the Participants (see Table 9-1).

As regards the publication of the Final Market Coupling Results, this shall be done by 13:55 EET under normal circumstances. However, as the final round of validation could take longer, the Participants are advised to consider this time only as an estimated (indicative) one. In this context, in case of severe delays in the Market Coupling process (due to running of a Second Auction, the triggering of Partial Decoupling, technical issues, etc.) the publication of the Final Market Coupling Results may be delayed until the Full Decoupling deadline (14:50 EET).

If a NEMO (in our case the NEMO designated in Greece) is decoupled from the Market

Coupling at 13:40 EET, this NEMO shall run Local Auctions for the Greek Day-Ahead Market and until 15:30 EET this NEMO shall publish the Local Market Results. If Local Auctions are run after the Market Coupling Full Decoupling at 14:50 EET, the deadline for publishing the Local Market Results is at 15:30 EET (in case no price thresholds are reached) and 15:45 EET (in case price thresholds are reached and a Second Auction is triggered). At this point, it should be noted that if the Greece-Italy coupling is maintained after the Market Coupling Full Decoupling at 14:50 EET, the deadline for publishing the Regional Market Coupling Results is at 15:35 EET. If the regional coupling fails, a Local Auction shall be performed by the Market Operator and the Local Market Results shall be published at the latest until 15:55 EET.

Table 9-1 below lists all the messages (sent by the Market Operator) that inform the Participants about the delay in the Market Coupling Results publication in case the Greek Market Operator is still coupled within the Market Coupling and the Preliminary Market Coupling Results are not published at 13:42 EET. According to Table 9-1, if the Final Market Coupling Results are still not published at 14:00 EET, the Market Operator shall send another delay message. If the Final Market Coupling Results are still not available at 14:20 EET the Market Operator shall alert the Participants that there is a risk of Full Decoupling. Finally, if the Final Market Results are not available at 14:50 EET, a Full Decoupling shall be declared.

Sending Time	Message Title	Message Text
13:42 EET	[ExC[16]_02]: Delay in Market Coupling Results publication	Please be aware that the publication of the Market Coupling Results is delayed until further notice. The Market Coupling Results will be published as soon as they are available. If needed, another delay message will be sent out.
	or	
	[ExC_06]: Delay in Market Coupling Results publication due to Max price detected in a Bidding Area	Please be aware that the publication of the Market Coupling Results is delayed until further notice. This is due to Max prices detected in one or more of the Bidding Areas. Max price procedures have been triggered by [*specify the corresponding NEMO*]. The Market Coupling Results will be published as soon as they are available.
14:00 EET	[UMM[17]_01a]: Delay in final Market Coupling Results publication	The Market Coupling process is delayed due to technical reasons or market issues. Therefore, the publication of the Final Market Coupling

[16] External Communication (market message)

		Results is delayed.
14:20 EET	[ExC_03b]: Further Delay of the Market Coupling Session	Please be aware that the Market Coupling Session is delayed. Therefore, the Market Coupling Session encounters a risk of Full Decoupling. If the Final Market Coupling Results are still not available at HH:MM, another message will be sent out in order to announce the Full Decoupling.
The deadline for publishing the Final Market Coupling Results is 14:50 EET		

Table 9-1: Market messages in case of delay in publication of market coupling results (Greece remains coupled with the Market Coupling)

Table 9-2 below lists all the messages that inform the Participants about the delay in Local Market Results publication in case the Greek Market Operator is decoupled from the Market Coupling at 13:40 EET and Local Auctions shall be carried out. According to Table 9-2, the Participants shall be regularly informed about the delay in the publication of the Local Market Results (at 14:00, 14:20 and 14:50 EET).

Sending Time	Message Title	Message Text
14:00 EET	[UMM_01b]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
14:20 EET	[UMM_01c]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
14:50 EET	[UMM_01d]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.

[17] Urgent Market Message

The deadline for publishing the Local Market Results is 14:30 EET

Table 9-2: Market messages in case of delay in publication (Greece is decoupled from the Market Coupling)

9.2 Second Auction within the Market Coupling

If high or low price thresholds are detected in one of the coupled Bidding Areas for which price thresholds are defined, the Market Operator shall send a message to inform the Participants about the triggering of a Second Auction. It should be noted that the Greek Market Operator has the possibility to define price thresholds that will trigger a Second Auction in case they are violated.

In any case the Market Operator shall reopen the Order Book for 10 minutes at a time indicated in a market message (see Table 9-3). Under normal circumstances, the reopening of the Order Books shall occur at around 13:45 EET. After the closing of the Order Books, a second calculation shall take place and the publication of the Market Coupling Results shall be considerably delayed. It should be noted that if prices still reach the predefined thresholds after the second calculation, no additional Auction shall be triggered due to time constraints.

Table 9-3 below presents the communication involved if a Second Auction is triggered within the Market Coupling.

Sending Time	Message Title	Message Text
As of 12:35 EET	[ExC_01]: Thresholds reached -Reopening of the order books	Due to the exceeding of the predefined price thresholds, a Second Auction is triggered. Consequently, the Order Book will be reopened at HH:MM for exactly 10 minutes. Therefore, the publication of the Market Coupling Results is delayed. High/Low prices are detected the following Bidding Areas and hours: Bidding Area / High/Low / Hours impacted
14:00 EET	[UMM_01a]: Delay in final Market Coupling Results	The Market Coupling process is delayed due to

Bidding Area	High/Low	Hours impacted

	publication	technical reasons or market issues. Therefore, the publication of the final Market Coupling Results is delayed.
14:20 EET	[ExC_03b]: Further Delay of the Market Coupling Session	Please be aware that the Market Coupling Session is delayed due to technical reasons or market issues. Therefore, the Market Coupling Session encounters a risk of Full Decoupling. If the Final Market Coupling Results are still not available at 14:50 EET, another message shall be sent out in order to announce the Full Decoupling.
The deadline for publishing the Final Market Coupling Results is 15:45 EET		

Table 9-3: Second Auction within the Market Coupling

9.3 Partial Decoupling within the Market Coupling

One of the core principles of the Market Coupling is to try to maintain coupled as many Bidding Areas/interconnectors as possible.

A Partial Decoupling is a situation where one or more Bidding Areas and/or interconnectors are temporary not participating in the Market Coupling while the remaining Bidding Areas/interconnectors still participate in the Market Coupling. The CZCs for the decoupled borders/interconnectors are allocated through the available fallback allocation solutions (Shadow Auctions).

The Market Coupling supports two different types of Partial Decoupling situations, depending on the reason leading to the decoupling. Figure 9-1 presents the two different types of Partial Decoupling indicating the actions to be followed for resolving each of them.

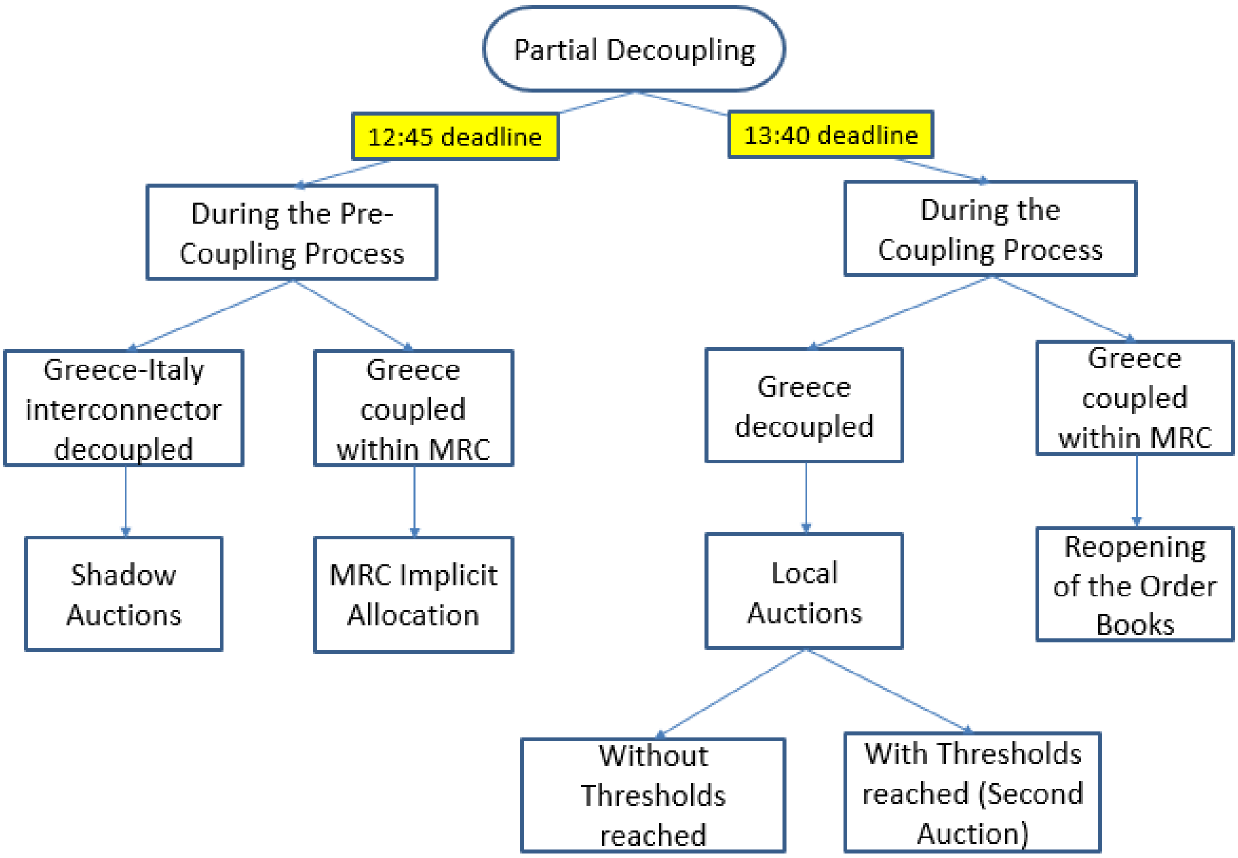

Figure 9-1: Partial Decoupling Situations

❖ **<u>Partial Decoupling during the pre-coupling process</u>**

If there are no CZCs available for a certain Market Coupling interconnector, a Partial Decoupling shall be declared at 12:45 EET. Consequently, the interconnector for which CZCs are missing is removed from the Market Coupling Session. In case of decoupling of an interconnector related to the Greek and Italian Market Operators, Shadow Auctions shall be carried out through the Joint Allocation Office (JAO)[18].

For the interconnectors that remain coupled, the Market Coupling Session continues and the regular publication time maintained (13:42 EET).

[18] Refer to the "Greece-Italy TSOs proposal for fallback procedure in accordance with Article 44 of the Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management" (paragraph 4 of Article 3). Available online: https://consultations.entsoe.eu/markets/fallback-procedure-for-greece-italy-capacity-calcu/

Table 9-4 below shows the communication involved in preparing and declaring a decoupling of an interconnector due to missing CZCs for running the Market Coupling.

Sending Time	Message Title	Message Text
12:15 EET	[UMM_02]: Risk of Partial Decoupling for one or more interconnectors	Please be aware that the Market Coupling process encounters severe technical issues or extraordinary market situations for the following interconnector(s): [*Interconnector name*] In case of Partial Decoupling, another message will be sent shortly after 12:45 to announce the decoupling of the concerned interconnectors.
12:45 EET	[UMM_03]: One or more interconnectors decoupled	Due to Network Data issues, the following interconnectors are decoupled from the Market Coupling: [*interconnector name*] For the interconnectors that remain coupled, please follow the Market Coupling rules as usual. For the decoupled interconnector, please follow the local auction rules.
The deadline for publishing the Final Market Coupling Results is 12:55 EET		

Table 9-4: Partial Decoupling during the pre-coupling process

❖ **Partial Decoupling during the coupling process**

If the Market Coupling is delayed due to a missing Order Book or other technical/market issues related to one particular NEMO, a Partial Decoupling shall be declared at 13:40 EET. Consequently, all the interconnectors and Bidding Areas related to that NEMO shall be removed from the Market Coupling Session.

As in the previous case, for the decoupled interconnectors, fallback allocation mechanisms are initiated. For the Bidding Areas that remain coupled, the Market Coupling Session continues as usual but the publication of the Market Coupling Results is delayed.

If the Greek Market Operator remains coupled within the Market Coupling following a

Market Coupling Partial Decoupling, the Order Books shall be reopened for 10 minutes at a time indicated in a market message, usually at 13:50 EET.

The Table 9-5 below presents the communication involved in preparing and declaring a decoupling of a NEMO due to missing Order Book for running the Market Coupling Session or for other technical reasons or market issues.

Sending Time	Message Title	Message Text
13:20 EET	[ExC_03a]: Risk of Partial Decoupling	Please be aware that the Market Coupling process encounters severe technical issues or extraordinary market situations for the following interconnector(s): [*Interconnector name*] In case of Partial Decoupling, another message will be sent shortly after 12:45 to announce the decoupling of the concerned interconnectors.
13:40 EET	[ExC_04a]: Partial Decoupling -Reopening of the Order Books	Due to technical reasons or market issues, the following area is decoupled from the Market Coupling: [*interconnector name*] As a consequence of the Partial Decoupling, the PX Order Books for the areas remained coupled will reopen at HH:MM for exactly 10 minutes. For the interconnectors that remain coupled, please follow the Market Coupling rules as usual. For the decoupled interconnector, please follow the local auction rules. *Please be aware that no Second Auction will be triggered if price thresholds are reached following the Partial Decoupling.* *This measure aims at avoiding a Full Decoupling due to insufficient time left to perform the Second Auction.* *Therefore, please use the opportunity of adjusting your orders during the 10 minutes communicated above, considering that decoupling situations are likely to*

		determine the occurrence of extreme prices.
The deadline for publishing the Final Market Coupling Results is 13:50 EET		

Table 9-5: Partial Decoupling during the coupling process (Greece remains coupled with the Market Coupling)

If the Greek Market Operator is decoupled from the Market Coupling at 13:40, Local Auctions shall be carried out for the Greek internal market.

The Market Operator shall reopen the Order Book for 10 minutes at a time indicated in a market message, usually after 13:55 EET. The Market Operator shall regularly keep the Participants informed if the Local Market Results are not published yet at 14:00, 14:20 and 14:50 EET.

The Table 9-6 below presents the communication involved in running a Local Auction, without thresholds reached, after the Greek NEMO is decoupled from the Market Coupling.

Sending Time	Message Title	Message Text
As of 13:45 EET	[UMM_04]: Order book reopening for local auction after Partial Decoupling	As a consequence of the decoupling, the Order Book will reopen at HH:MM for exactly 10 minutes and a Local Auction will be run.
14:00 EET	[UMM_01b]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
14:20 EET	[UMM_01c]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
14;50 EET	[UMM_01d]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
The deadline for publishing the Local Market Results is 15:30 EET		

Table 9-6: Partial Decoupling during the coupling process (Greece is decoupled and Local Auctions are not reached price thresholds)

If following the running of a Local Auction thresholds are reached for the Greek internal market, a Second Auction shall be triggered. The Market Operator shall reopen the Order Book for 10 minutes at a time indicated in a market message, usually after 13:55 EET. The Market Operator shall regularly keep the Participants informed if the Local Market Results are not published yet at 14:00, 14:20 and 14:50 EET.

The Table 9-7 below shows the communication involved in running a Local Auction, with thresholds reached (Second Auction), after the Greek NEMO is decoupled from the Market Coupling.

Sending Time	Message Title	Message Text
As of 13:45 EET	[UMM_04]: Order book reopening for local auction after Partial Decoupling	As a consequence of the decoupling, the Order Book will reopen at HH:MM for exactly 10 minutes and a Local Auction will be run.
14:00 EET	[UMM_01b]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
As of 14:05 EET	[UMM_05]: Thresholds reached during Local Auction -Reopening of the Order Book	Due to the exceeding of the predefined price thresholds, a Second Auction is triggered. Consequently, the Order Book will be reopened at HH:MM for exactly 10 minutes. Therefore, the publication of the Market Coupling Results is delayed.
14:20 EET	[UMM_01c]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
14;50 EET	[UMM_01d]: Delay in Local Market Results publication	Please be aware that the Local Market Results publication is still delayed due to technical reasons or market issues.
The deadline for publishing the Local Market Results is 15:30 EET		

Table 9-7: Partial Decoupling during the coupling process (Greece is decoupled and Local Auctions are reached price thresholds)

9.4 Full Decoupling of Market Coupling

If the Final Market Coupling Results are not available at 14:50 EET, a Full Decoupling of the Market Coupling shall be declared. If the issue having caused the Full Decoupling does not come from the Greek NEMO or from the respective Italian NEMO, the Greece-Italy Coupling shall be started as shown in Figure 9-2.

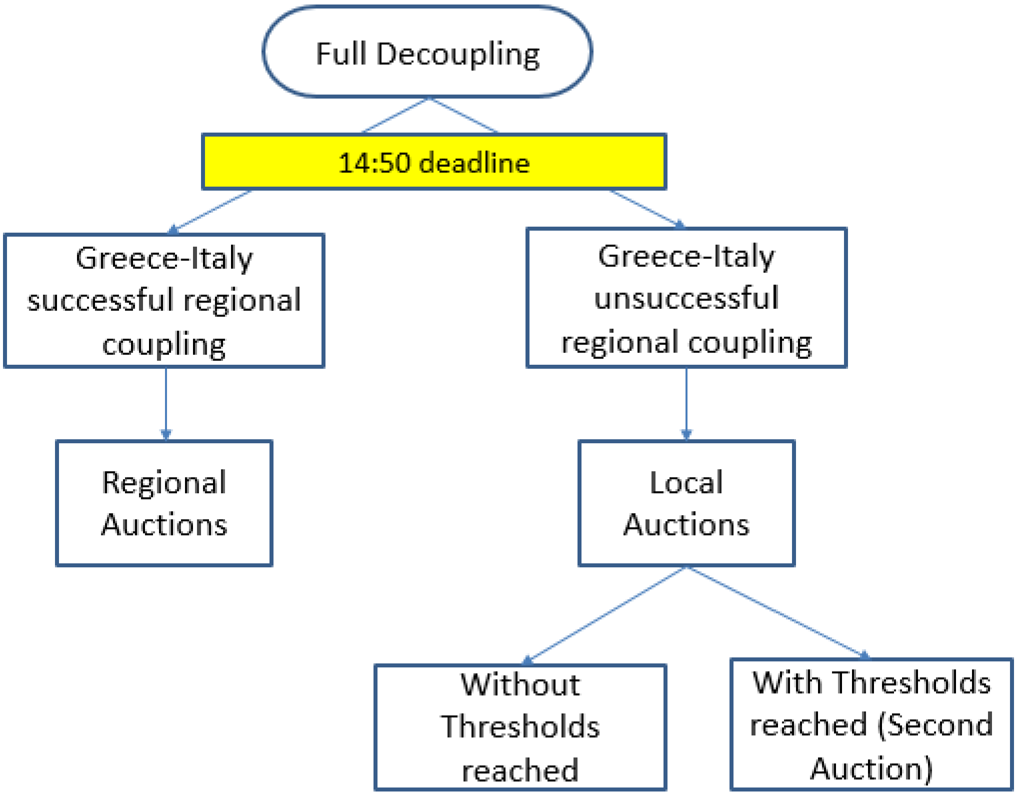

Figure 9-2: Full Decoupling Situations

The Market Operator shall reopen the Order Book for 10 minutes, at a time indicated in a market message, usually at 14:58 EET. Consequently, the Participants may submit new Orders on the Energy Trading System. However, if no new Orders are submitted, the previously submitted ones are kept unchanged. After the Order Books are closed, the Market Operator shall run the Greece-Italy Regional Coupling.

If price thresholds are reached, a Second Auction shall not be triggered and Order Books shall not be reopened.

Table 9-8 below lists the messages that inform the Participants about the risk and the declaration of the Full Decoupling. Also, the Full Decoupling message contains the time of the reopening of the Order Books for 10 minutes.

Sending Time	Message Title	Message Text
14:20 EET	[ExC_03b]: Further Delay of the Market Coupling	Please be aware that the Market Coupling Session is

	Session	delayed. Therefore, the Market Coupling Session encounters a risk of Full Decoupling. If the Final Market Coupling Results are still not available at 14:50 EET, another message will be sent out in order to announce the Full Decoupling.
14:50 EET	[ExC_04b]: Full Decoupling	Due to technical reasons or market issues, the whole price coupled area is fully decoupled. Please follow the local auction rules of each PX. Please be aware that for the Greek Market Operator, the following option has been decided: The Greek borders remain coupled to the Italian ones. Consequently, the Order Books will be reopened at 14:58 EET for exactly 10 minutes. A regional coupling will take place, followed by the publication of regional Market Coupling Results for these Bidding Areas.
The deadline for publishing the Regional Market Results is 15:35 EET		

Table 9-8: Full Decoupling of the Market Coupling followed by a Greece-Italy Regional Coupling

If the Regional Market Coupling Results are not available at 15:35 EET, a Regional Decoupling shall be declared. Consequently, all borders are decoupled and the fallback allocation shall be used. As a result, Greece and Italy are decoupled from each other.

Under these conditions, the Market Operator shall reopen the Order Book for 10 minutes, at a time indicated in a market message, usually at 15:40. The Participants may submit new Orders on Energy Trading System. However, if no new Orders are submitted, the previously submitted ones are kept unchanged.

The Market Operator will run separate Local Auctions for the Greek internal market.

If price thresholds are reached, a Second Auction shall not be triggered and Order Books shall not be reopened.

Table 9-9 below lists the messages that inform the Participants about the declaration of the Regional Decoupling. Also, the decoupling message contains the time of the reopening of the Order Book for 10 minutes.

Sending Time	Message Title	Message Text
15:35 EET	[UMM_07]: Regional Decoupling –Reopening of the Order Books for local auctions	Due to technical reasons or extraordinary market issues, the regional coupling cannot be performed. As a consequence of the decoupling, the Order Books will be reopened at 15:40 EET for exactly 10 minutes and a Local Auction will be run.
The deadline for publishing the Regional Market Results is 15:35 EET		

Table 9-9: Full Decoupling of the Market Coupling followed by an unsuccessful Greece-Italy Regional Coupling and Local Auctions

If the Final Market Coupling Results are not available at 14:50 EET, a Full Decoupling of the Market Coupling shall be declared. If the issue having caused the Full Decoupling does come from the Greek NEMO, Local Auctions shall be carried out.

The Market Operator shall reopen the Order Book for 20 minutes, at a time indicated in a market message, usually at 14:58 EET. Consequently, the Participants may submit new Orders on the Energy Trading System. However, if no new Orders are submitted, the previously submitted ones are kept unchanged. After the Order Books are closed, the Market Operator shall run the Local Auctions.

If price thresholds are not reached, a Second Auction shall not be triggered.

Table 9-10 below lists the messages that inform the Participants about the risk and the declaration of the Full Decoupling. Also, the Full Decoupling message contains the time of the reopening of the Order Books for 20 minutes.

Sending Time	Message Title	Message Text
14:20 EET	[ExC_03b]: Further Delay of the Market Coupling Session	Please be aware that the Market Coupling Session is delayed. Therefore, the Market Coupling Session encounters a risk of Full Decoupling. If the Final Market Coupling Results are still not available at 14:50 EET, another message will be sent out in order to announce the Full Decoupling.
14:50 EET	[ExC_04b]: Full Decoupling	Due to technical reasons or market issues, the whole

		price coupled area is fully decoupled. Please follow the local auction rules of each PX. The Greek market is decoupled. Local auctions will be run. Order Books will be reopened at 14:58 EET for exactly 20 minutes.
The deadline for publishing the Regional Market Results is 15:30 EET		

Table 9-10: Full Decoupling of the Market Coupling followed by Local Auctions without price thresholds reached

If price thresholds are reached, a Second Auction shall be triggered and Order Books shall be reopened for 10 minutes.

Table 9-11 below indicates the message that informs the Participants about the triggering of a Second Auction after a Full Decoupling.

Sending Time	Message Title	Message Text
As of 15:25 EET	[UMM_05]: Thresholds reached during local auction -Reopening of the order book	Due to the exceeding of the predefined price thresholds during the local auction, a Second Auction is triggered. Consequently, the Order Book will be reopened at HH:MM for exactly 10 minutes.
The deadline for publishing the Local Market Results is 14:30 EET		

Table 9-11: Full Decoupling of the Market Coupling followed by Local Auctions with price thresholds reached (Second Auction)

10 Annex A: ATC-based and Flow-based congestion management models

The starting point of any market integration is to agree on common and reasonably efficient principles for calculating transmission capacities available for trading electricity. The basic methods for this calculation, as these have been addressed within the scope of the European electricity market integration, are the following:

a) the ATC-based model, and

b) the flow-based model.

10.1 ATC-Based Model

The primary method pre-dating the Target Model has been for each Control Area to calculate bilateral energy exchange capacities (Available Transfer Capacity, ATC) towards each of its neighbors, in both directions. Thus, for each interconnector and commercial direction, two ATC values are calculated by the respective TSOs. In general, the lower of the two values is accepted as the capacity to be available to the market.

Energy exchanges in a meshed electricity transmission system do not follow a scheduled route, but are distributed according to the laws of physics on all possible routes between two points. Therefore, the amount of actual transfer between two points in the transmission system is likely to have an effect on the amount of available transfer between any other pair of points.

> ***The ATC-based congestion management model is not technically accurate because capacity allocation in many cases does not follow the distribution of the actual power flows.***

Let us look at an example. If countries A, B and C are neighboring and all connected to one another, then an electricity export from A to B partly flows on the indirect route A→C→B, and thus also influences the amount of transmission capacity left for transfers from C to B. Therefore, determining the cross-border capacity available for transfers from C to B, without knowing energy transfers from A to B might endanger, system security.

10.2 Flow-Based Model

This Section presents the system constraints that will be included in the market clearing as well as the methodology used by the TSOs to calculate the parameters of these constraints. As such, it is an essential part of the market framework and the rules for the market clearing.

Flow-Based market coupling is the preferred market design according to Article 20 (1) of the CACM Regulation. The basic idea separating the flow-based approach from the current Coordinated Net Transmission Capacity (CNTC) is the direct relation of flows between neighboring zones with the allocated capacities among them. This change introduces the ability for the market to prioritize flows that are most economically efficient in managing congestions. This is in contrast to the ATC-based methodology where operators are making decisions on capacity allocations in advance of the market clearing.

With CNTC, only commercial exchanges between Bidding Zones are considered by the market algorithm. Real physical flows, including transit flows, are left to the TSO to manage. As transit flows are hard to predict, capacity calculations in meshed grid becomes more complex.

The Flow-based congestion management model incorporates a basic grid model with all Critical Network Elements in the market clearing algorithm and as such is much more technically accurate and consequently more efficient.

Flow-based calculation approach does things differently. The transmission capacities provided to the market come together with information on the physical flows (linearized as such) on all Critical Network Elements (CNE), induced by a change in the Net Position in every Bidding Zone. Transit flows are then monitored and overloads are managed directly by the market algorithm. The TSO can provide maximum capacity to the market, and the market algorithm will find the optimal welfare economic flow on all grid components by itself.

Because the TSO shall not prioritize capacity on certain border in advance, more solutions are available to the market algorithm. This implies that theoretically the solution domain, given to the market by a flow-based capacity calculation, is as large as or larger than the CNTC domain. All CNTC market solutions are available to the flow-based market coupling, but the flow-based market coupling provides access to solutions outside the CNTC solution domain. Whenever the optimal solution is within the CNTC domain, both market designs will find it, but the flow-based market coupling may find an optimum outside what is available to the CNTC. In theory, the flow-based market coupling has to be more efficient than the CNTC at the same level of system security, while practical implementation may sometimes prove otherwise.

10.2.1 Grid constraints limit the domain for the market solution

The generic market optimization problem may be formulated as:

- **<u>CNTC formulation</u>:**

  Objective function: Maximize welfare economic surplus

  Subject to: $\sum NPs = 0$,

  CNTC constraints

- **<u>FB formulation</u>:**

  Objective function: Maximize welfare economic surplus

  Subject to: $\sum NPs = 0$,

  Flow-based constraints

where:

NP (Net Positions) = Supply – Demand

Without diving into the mathematics of these relations, they point to the fact that the objective function is the same for CNTC and flow-based, while the constraints are different. The objective function is to maximize total welfare economic surplus in the power market, which is the sum of producer surplus, consumer surplus and congestion income.

The constraints are limiting the solution domain of the market optimization problem, and they are the key to understand why the flow-based approach may provide a better solution than CNTC. The fact is that, given the same level of operational security, the boundaries of the flow-based domain will always be located on or outside the boundaries of the CNTC domain. **<u>This implies that if the optimum market solution is found within the CNTC domain, both CNTC and flow-based will find the same solution. However, the optimum solution may be within the flow-based domain, but outside the CNTC domain.</u>**

10.2.2 Coordinated Net Transmission Capacity and Flow-based Constraints

We can illustrate the difference between the FB and the CNTC using a simple three-node grid (Figure 10-1). In this example, all lines have a thermal capacity of 1000 MW and equal impedance (equal "electrical distance"). Node C is a consumption node, and the nodes A and B are generation nodes. The question faced by the TSO, is how much capacity can be provided to the market for each line (identified as CNE).

At the time of capacity calculation (D-1), the TSO does not know which node (A or B) is to produce. The physical property of the grid is however known. Due to the described grid topology, one MW produced in node A will induce a flow of 2/3 MW on the line AC, 1/3 MW on the line AB, and 1/3 MW on the line BC. The same holds for generation in node B of which -1/3 appears on AB, 1/3 on AC and 2/3 on BC. These sensitivity factors are commonly referred to as Power Transfer Distribution Factors (PTDF). Node C is the slack node, and all power injected in A and B is absorbed in this slack. The same holds for node C itself: all power injected in C is absorbed in the slack node C, as such node C individually has no influence on the flows in the grid. The flow influence of each node to each line comprises the PTDF matrix (Table 10-1).

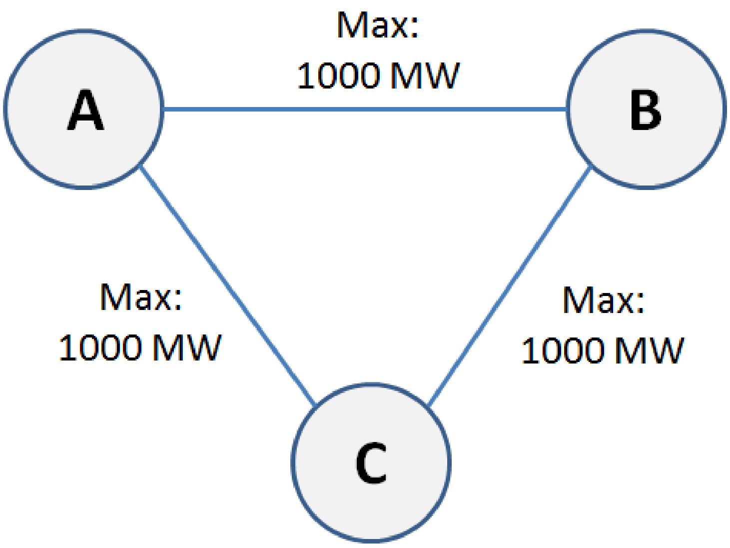

Figure 10-1: Grid with three nodes

The PTDF factors, translating the change in net positions into physical line flows, are not provided to the market algorithm under the traditional CNTC. Within the CNTC approach, transit flows are ignored and the algorithm only relates to the total provided capacity on each border. This implies that one MW produced in A and consumed in C will bring an "CNTC load" of for example 0.5 MW on the lines AB and BC, and 0.5 MW on AC (we are referring to the CNTC method, not the flow-based method). Bluntly setting the CNTCs to thermal limit values, would allow the CNTC market algorithm to carry 2,000 MW of trade from A to C, or from B to C even though it is not physically feasible and will create an overload.

A -> B	1000	1/3	-1/3	0
A -> C	1000	2/3	1/3	0
B -> C	1000	1/3	2/3	0

Table 10-1: PTDF matrix of the grid

The physical reality in our small three-node example, reflected by the PTDFs, is that 2,000 MW generated in A will load AC with 2/3 * 2,000 = 1333 MW, which is above the thermal capacity of that line. The maximum generation (net position) in each of the nodes A and B (one at a time) that is possible in order to avoid overloads, is 1,500 MW (however not simultaneously in nodes A and B). (In this example we do not analyze the case of producing half (e.g. 1,000 MW) in node A and half (e.g. another 1,000 MW in node B). The operator (TSO) has to limit the total export from A and B to this level under the CNTC approach. One possible set of ATC capacities that can be provided to the market will be a capacity of 750 MW on AC, BC and AB, which gives a secure CNTC solution domain. This is also the maximum simultaneous net positions that can be obtained **with the CNTC approach** in the presented network. The solution ATC domain is illustrated in Figure 10-2. (Note, in this example we present the CNTC approach. The flow-based approach provides a better utilization of the interconnections, as described in this Section).

The solution domain indicates which net positions are physically safe within a particular grid topology. What the CNTC market optimization expresses is: find the optimum market position inside the (CNTC) domain (indicated by the blue lines in Figure 10-2).

When flow-based constraints are provided to the market, the solution domain (or security domain) will change. The flow-based constraints consist of both information on flows induced (PTDFs) and the CNE-capacities given to the market called Remaining Available Margins (RAM). In our small three-node example, the RAM is 1,000 MW on each line (N-1 and security margins are ignored). As with CNTC, a net position of 1,500 MW for each of A and B is still feasible within FB. However, the larger maximum simultaneous net position of 1,000 MW for A and B also becomes possible with FB. This corresponds to the net positions of A=1000, B=1000, C= -2000 (point 1 in Figure 10-2). Flow induced on AC is 1000*(2/3) + 1000*(1/3) = 1000, the flow on BC is 1000*(1/3) + 1000*(2/3) = 1000, and the flow on AB is 1000*(1/3) + 1000*(-1/3) = 0.

Another market position accessible in FB but not in CNTC, is a net position of 2,000 MW for both A and B (but not simultaneously) illustrated as point 2 in Figure 10-2. A net position of 2,000 MW for A corresponds to the following net positions A=2000, B=-1000, C=-1000, and the flow induced on line AB is 2000*1/3 -1000*(-)1/3 -1000*0=1000.

If all such "extra" points are added to the former CNTC domain, we have the FB domain, which is shown in grey in Figure 10-2. In all situations where the optimal solution is found within the grey area, but outside the blue area, the FB solution is a better solution in terms off welfare economics than the ATC solution.

All points on the FB boundaries reflect congested situations somewhere in the grid that will induce price differences in all nodes without implying that all lines are congested simultaneously. These market positions are however not possible in CNTC due to the fact that the CNTC algorithm does not know the real physical flows (the PTDFs) between bidding zones.

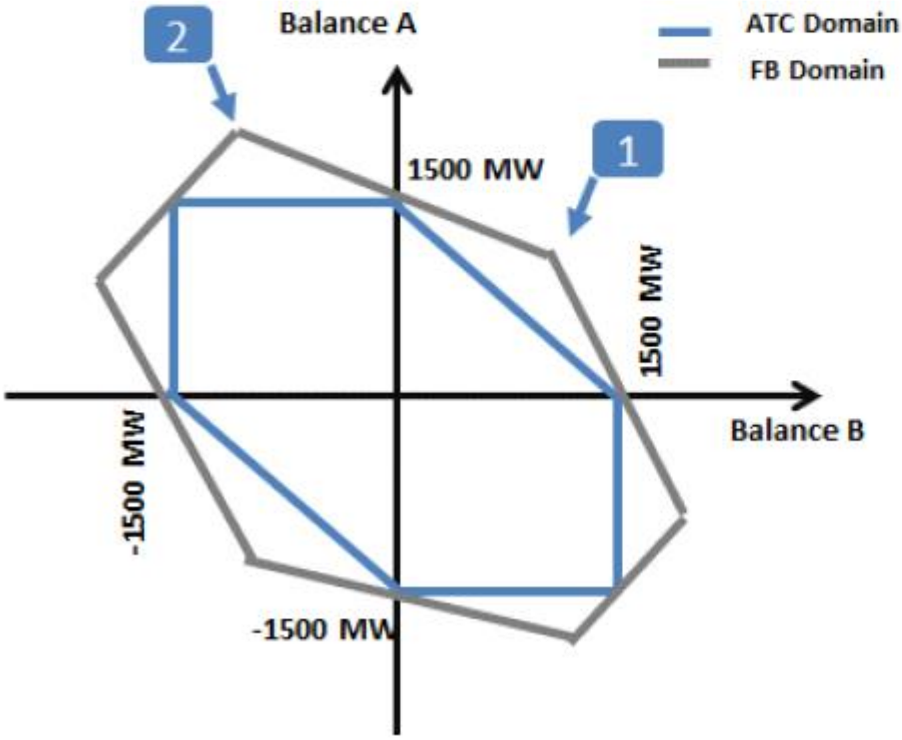

Figure 10-2: ATC and FB solution domains

10.2.3 Nodes and Bidding Zones with Flow-based approach

In Section 10.2.2 the implementation and implications of the flow-based constraints in the market algorithm based on Bidding Zones has been presented. In the three-node example of Section 10.2.2 most issues are easy to understand. For realistic problems, of course, complexity increases. Amongst other things, physical connections are between single nodes, while Bidding Zones comprise multiple nodes. When creating grid models in the real world to be used for flow-based parameter calculations, everything is based on nodes and single lines, rather than bidding zones and tie-lines.

This means that the nodal calculations and results have to be aggregated to Bidding Zones and Critical Network Elements (CNEs). As each node within the same Bidding zone has a different node-to-CNE PTDF, it has to be found an optimal strategy to make an aggregate zone-to-CNE PTDF. In case the node-to-line PTDFs were to be used directly by the market algorithm, then the resulting model would lead to a nodal pricing market design. By using the same technology but aggregating to Bidding Zones and CNEs, we acquire what is known as Flow-Based Market Coupling (FBMC).

10.2.4 Flow-Based Market Coupling Processes of TSOs

In the pre-coupling process the TSOs perform the following tasks:

1. Create a "base case" containing expected grid topology for the next day together with expected Net Positions of all Bidding Zones and corresponding flows on all CNEs.
2. Define GSKs, CNEs, the corresponding outages and Remedial Actions
3. Define and apply operational experience (Final Adjustment value, FAV) in order to adjust the FB domain.
4. Apply GSKs and CNEs to do the parameter calculation creating PTDFs and market margins (capacities).
5. Verify the FB parameters, making sure that the domain is proper.
6. Send the parameters to the NEMOs.

In the post-coupling process the TSOs perform the following tasks:

1. Verify the market results
2. Share the congestion income
3. Perform analyses of operational security

10.2.5 Capacity Calculation Uncertainty

The fundamental element in managing uncertainty in capacity calculation is the reliability margin (Flow Reliability Margin or FRM in FB). Due to uncertainty, the power system operator cannot predict precisely what flow will be realized on each CNE in the hour of operation. The flow may be larger or smaller than anticipated, and if the flow turns out larger, there may result in an overload on a CNE. In order to reduce the probability of physical overloads to an acceptable risk level, some of the capacity on a CNE will be retained from the market as an FRM. The capacity provided to the market will be the maximum capacity on a CNE less the FRM. The size of the FRM will normally be based on a statistical evaluation of the deviations between the flows estimated by the FB method and the actual flows observed.

There are many reasons why uncertainty occurs in capacity calculation, such as temperature, precipitation, fuel prices and sun. However, there are two uncertainties that are fundamental and specific to FB procedure. The first is the linearization of the grid model. The second is the manner in which we choose to aggregate the

node-to-CNE PTDFs to zone-to-CNE PTDFs. On the other hand, the flows between Bidding Zones are solved by the market itself when FB is applied. This means that transit flows are calculated in the FBMC, which reduces these kinds of uncertainties.

All uncertainties will however be reflected in the Flow Reliability Margin (FRM) which reduces the market capacity compared to the physical capacity.

Restrictions on market transmission capacity resulting from the Flow Reliability Margin (FRM) creates market inefficiencies that should be minimized if possible.

10.3 CACM Regulation Requirements related to Flow-Based Model

The Electricity Target Model, as described in the CACM Regulation, requires the development and use of a Common Grid Model (including common base cases) for at least the synchronous continental European transmission system, but preferably for the whole European mosaic. In Article 20 the CACM Regulation strongly recommends the application of flow-based capacity calculation and allocation methods.

The use of the CNTC-based model is also permitted, but only for non-meshed systems, or in the case of large islands and peninsulas, or in cases where the application of the flow-based approach does not lead to an increase in social welfare with the same level of system security. The main point is to avoid the trading between two Bidding Zones to have external (i.e. not-paid-for) effects on other Bidding Zones. Wherever considerable loop-flows are generated between Bidding Zones, this goal is only achieved by the flow-based approach.

10.4 Flow-Based Capacity Calculation Process

In this Section, we explain all activities performed by the TSOs in order to produce grid constraints to be used by the allocation mechanism (i.e. capacity calculation) in detail. In the following we dive into how the FB parameters are calculated and which simplifications are made.

We start off by explaining the relation between the physical grid (described by the AC load flow equations) and the PTDFs that the TSOs provide to the market algorithm. Subsequently, we explain the other central parameter, the market margin (Remaining Available Margin, RAM). The rest of the Section is dedicated to explain how to deal with GSKs, CNEs, DC cables, reliability margins, and further details behind the FB parameters.

10.4.1 The sensitivity parameters (PTDF)

The Direct Current (DC) Load Flow, the method for calculating the power flows caused in a set of load and generation data, is an analytical technique extensively used in the management of the transmission system. Alternate Current (AC) Load Flow gives accurate results but contains nonlinear relationships between problem variables and requires iterative methods to solve it. However, current methodologies can solve this AC nonlinear problem by successive iterations at extremely fast computations times.

The DC simplification gives us a set of linear equations that connects the phases of the bus voltages with the active power injections at the system nodes.

The DC Load Flow model is based on the following assumptions:

a) the magnitude of the bus voltage is fixed and equal to their nominal voltage (1 p.u.),

b) the transmission lines have zero resistances, thus there are no transmission losses, and

c) the phases of the bus voltages are variable, but the difference between them (in adjacent buses) is small.

Taking into account the above-mentioned assumptions, the active power flow in a transmission line *ij* is given by the following equation:

$$F_{ij} = \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right) \quad (1)$$

According to the power conservation principle, the total power injection at the bus i (difference in generation minus the load on the bus) is equal to the sum of the power flows of the lines connected to the bus:

$$P_i - D_i = \sum_j F_{ij} = \sum_j \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right) \quad (2)$$

Taking the power injection equations in all system buses, the system DC Load Flow equations are formed, which can be attributed in three different ways, as follows:

<u>1st case:</u>

$$\boldsymbol{B} \cdot \boldsymbol{\theta} = \boldsymbol{P} - \boldsymbol{D} \quad (3)$$

$$\theta_{ref} = 0 \quad (4)$$

where the matrix $\mathbf{B}$ contains the line and column corresponding to the reference bus, but the cross-sectional element of the reference bus is not grounded through large (practically infinite) conduction to the earth. Therefore, the matrix is non-reversible ($\det(\mathbf{B})=0$). Thus, equation (4) is necessary for the zeroing of the system reference bus.

2nd case:

$$\widehat{\boldsymbol{B}} \cdot \widehat{\boldsymbol{\theta}} = \widehat{\boldsymbol{P}} - \widehat{\boldsymbol{D}} \quad (5)$$

where the matrix $\hat{\mathbf{B}}$ does not contain the line and column corresponding to the reference bus. Correspondingly, the vectors, $\hat{\boldsymbol{\theta}}$, $\hat{\mathbf{P}}$ and $\hat{\mathbf{D}}$ do not contain the element corresponding to the reference bus.

3rd case:

$$\boldsymbol{B}_G \cdot \boldsymbol{\theta} = \boldsymbol{P} - \boldsymbol{D} \quad (6)$$

where the matrix $\mathbf{B}_G$ contains the line and column corresponding to the reference bus but it has a high admittance (ground) in the diagonal element corresponding to the reference bus, which sets equal to zero the reference bus phase, $\theta_{ref} = 0$.

The solution of the DC Load Flow problem requires that the topology and the transmission system parameters, as well as the power injections in all the buses of the power system, be centralized.

10.4.1.1 Power flow sensitivity analysis in the system

The Power Flow sensitivity analysis in a power system is used to quantify the effect, of a power exchange or a transmission line or a generating unit loss, on the system transmission lines through appropriate coefficients. The calculation of the Power Transfer Distribution Factors (PTDFs) is very important for the management of the transmission system.

The power flow sensitivity in a line *ij* with respect to the power injection in the bus k, α_k^{ij}, is defined as the percentage of the injected power at the bus k passing through the line *ij*. It is considered to withdraw an equal amount of power at the reference bus, so α_k^{ij} expresses the percentage of the power exchange from the bus k to the reference bus passing through line *ij*. Taking into account the DC Load Flow assumptions, from (1) we have:

$$F_{ij} = \frac{1}{x_{ij}}\left(\theta_i - \theta_j\right) = \frac{1}{x_{ij}} \boldsymbol{e}_{ij}^T \cdot \boldsymbol{\theta} = \frac{1}{x_{ij}} \boldsymbol{e}_{ij}^T \cdot [\boldsymbol{B}_G]^{-1} \cdot (\boldsymbol{P} - \boldsymbol{D}) \quad (7)$$

Therefore, the sensitivity α_k^{ij} is given by the following equation:

$$\alpha_k^{ij} = \frac{\partial F_{ij}}{\partial P_k} = \frac{1}{x_{ij}} \boldsymbol{e}_{ij}^T \cdot [\boldsymbol{B}_G]^{-1} \cdot \boldsymbol{e}_k \quad (8)$$

The sensitivities of a particular "monitored line" *ij* with respect to the power injections in all buses k of the system, excluding the reference bus (for which the sensitivity is by default zero), can be calculated via a simple forward-backward substitution with the triangular matrix of the symmetric network susceptance matrix $\mathbf{B}_G$, using the following equations:

$$\boldsymbol{R}^{ij} = [\boldsymbol{B}_G]^{-1} \cdot \boldsymbol{e}_{ij} \quad (9)$$

$$\alpha_k^{ij} = \frac{1}{x_{ij}} \left(\boldsymbol{R}^{ij}\right)^T \boldsymbol{e}_k = \frac{1}{x_{ij}} R_k^{ij} \quad (10)$$

The power flow sensitivities across all lines *ij* with respect to the power injection in a specific bus k (and withdrawal of an equal amount of power from the reference bus) can also be calculated by a forward-backward substitution of a sparse matrix with the triangular factors of matrix $\mathbf{B}_G$:

$$\boldsymbol{Y}_k = [\boldsymbol{B}_G]^{-1} \cdot \boldsymbol{e}_k \quad (11)$$

$$\alpha_k^{ij} = \frac{1}{x_{ij}} \boldsymbol{e}_{ij}^T \cdot \boldsymbol{Y}_k = \frac{1}{x_{ij}} \left(Y_{ik} - Y_{jk}\right) \quad (12)$$

where $\mathbf{Y}_k$ is the k column of the inverse matrix of the system susceptance matrix:

$$\boldsymbol{Y} = [\boldsymbol{B}_G]^{-1} \quad (13)$$

10.4.1.2 Power Flow sensitivity in a line due to a power exchange between two buses (Power Transfer Distribution Factor, PTDF)

As power exchange between two buses is defined the production of a quantity of active power in one bus and the withdrawal of the same amount of power from the other bus. A power exchange from the bus m to the bus n results in the change of the flow in line *ij* by:

$$\Delta F_{ij} = PTDF_{ij,mn} \cdot P_{mn} \quad (14)$$

where P_{mn} is the amount of the exchange from the bus m to the bus n, while the Power Transfer Distribution Factor, $PTDF_{ij,mn}$, expresses the percentage of the exchange from bus m to bus n passing through line *ij* and it is calculated as follows:

$$PTDF_{ij,mn} = \alpha_m^{ij} - \alpha_n^{ij} = \frac{1}{x_{ij}}\left(Y_{im} - Y_{jm} - Y_{in} + Y_{jn}\right) \quad (15)$$

10.4.2 From Nodal PTDFs to Bidding Zone PTDFs using Shift Keys

In the FBMC model zone-to-CNE PTDFs are used by the market algorithm to assess whether a change in area balance respects the grid constraints. The PTDFs are calculated based on an estimated base case for each hour of operation. The base case describes the anticipated grid topology, net positions and corresponding power flows in each hour of operation on a nodal level for day D. The base case is created either by using D-2 data, or a combination of D-2 data and forecasts for generation and consumption.

The Base Case is derived from snapshots (SN) from the SCADA systems. A snapshot represents the power flow of a TSO's transmission system at a specific time instance, showing the voltages, currents, and power flows in the grid at that instance. The snapshot is adjusted by including anticipated changes in grid topology, production and consumption (both planned outages and forecasts) for the hour of Day D and forms the base case.

<u>**The PTDFs computed from the base case represent node-to-CNE PTDFs. The FB methodology however requires Zone-to-CNE PTDFs, where net positions of Bidding Zones result in the flow on particular CNEs. This creates a need for calculating zone–to-CNE PTDFs from the node-to-CNE PTDFs. This is a serious approximation that renders the FBMC architecture inferior to the nodal design but a step in the right direction compared to the ATC-based model.**</u>

Figure 10-3 shows three bidding zones, A, B and C, each consisting of five nodes (N1-N5). These nodes are connected by both internal lines and tie lines between the areas. The task at hand is to convert the node-to-CNE PTDFs into zone-to-CNE PTDFs.

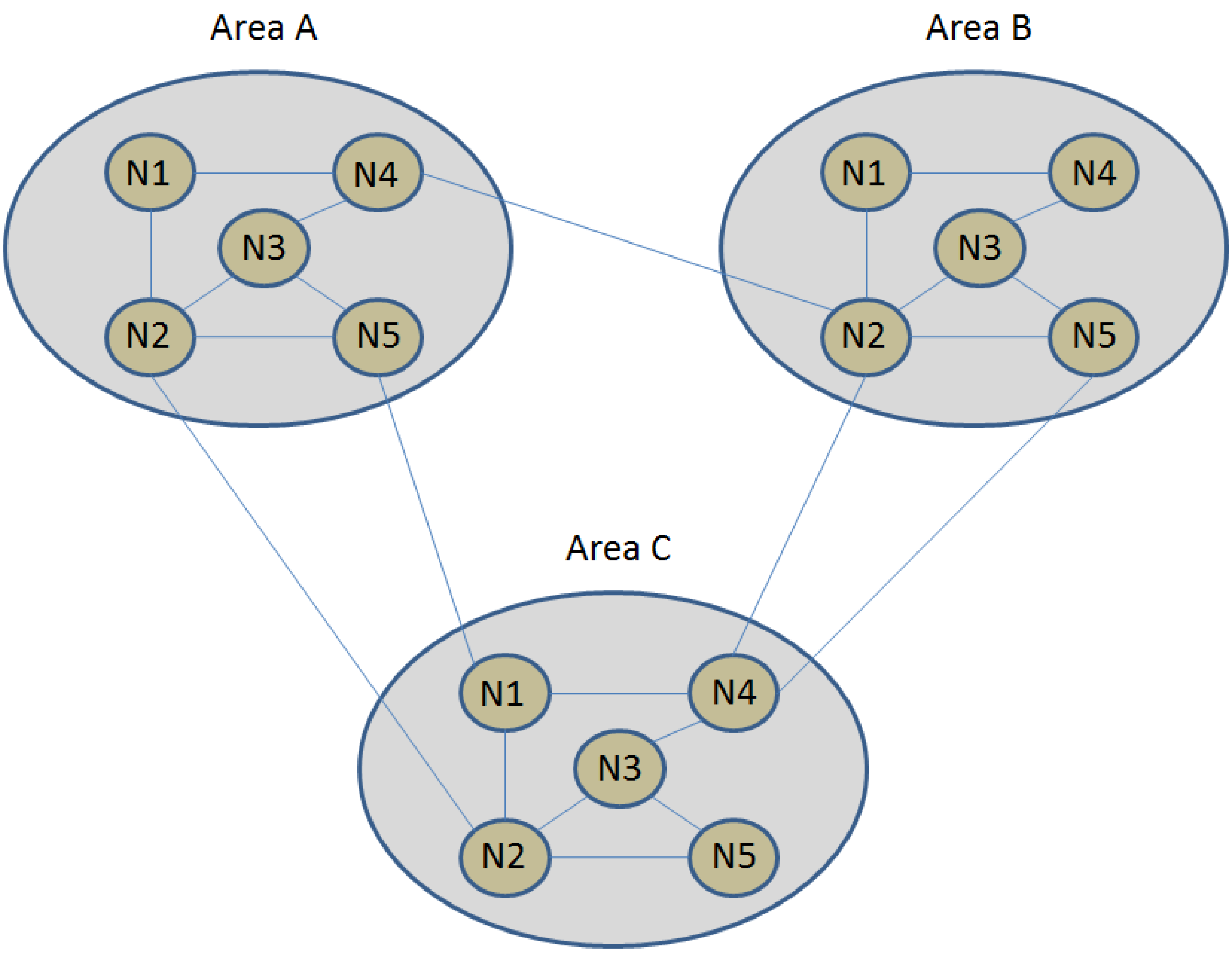

Figure 10-3: From Nodes to Bidding Zones

An aggregation problem arises from the fact that each node within the same area has a particular influence on each line or CNE. If one particular node gets too much or too little weight in the aggregation, the zone-to-CNE PTDF is inaccurate. Unfortunately, there is no straightforward theoretical way of finding the "correct" rule for aggregation.

In Figure 10-3, the difference in nodal and area PTDFs can be illustrated by the fact that the impact of N4 in "A" will probably be different from the impact of N5 in "A" on the flow on the tie line between area "A" and "C". If the aggregation is not in line with reality, the zonal PTDFs will behave as a poor estimate for actual flows. **One further problem is that the most viable rule for aggregation is dynamic and based on actual experience it can substantially change over time. Therefore, continuous updates, based on studies are required to keep the models approximately optimal, that may provide results that have different impact from operational and financial perspective to various Participants. As such, politically, this process is a futile way to attempt to maintain an approximate optimal grid configuration.**

The FB model makes use of shift keys to describe how the net position of one node changes with the net position of the area it is a part of. We can have different shift keys related to consumption and generation, and even related to different technologies (like wind shift keys). In this context however, we'll use the general term generation shift keys (GSK).

The GSK is a parameter used in the translation from node-to-CNE PTDFs to zone-to-CNE PTDFs. The relation is formally expressed as:

$$PTDF_{i,j}^{A} = \sum GSK^{\alpha} \cdot PTDF_{i,j}^{\alpha}$$

$$\sum GSK^{a} = 1$$

where:

$PTDF_{i,j}^{A}$	Sensitivity of line i,j to injection in area "A"
$PTDF_{i,j}^{\alpha}$	Sensitivity of line i,j of injection in node "α"
GSK^{α}	Weight of node α on the PTDF of area "A"

10.4.3 Remaining Available Margin (RAM)

The PTDF matrix is one of two fundamental parameters for providing grid constraints to the market optimization by the NEMO. The other is the Remaining Available Margin (RAM). This is the "free margin" that can be used by the allocation mechanism on CNEs. The RAM differs from the maximum capacity of the CNE as in the following equation.

$$RAM = F_{\max} - FRM - FAV - F_{ref}$$

where:

RAM	the Remaining Available Margin
F_{max}	the maximum allowed flow on the CNE
FRM	the Flow Reliability Margin
FAV	the Final Adjustment Value
$F_{ref'}$	the reference flow at zero net positions when using the computed PTDF

In this equation, Fref' is the reference flow at zero net position that is obtained by using the calculated PTDF matrix from the base case:

$$F_{ref'} = F_{ref} - PTDF \cdot NP^{BC}$$

where:

F_{ref}	the loading of the CNEs in the base case given the net positions reflected in the base case
NP^{BC}	Net position of all Bidding Zones in the base case

The relation between the net position, flow and RAM is illustrated in Figure 10-4. The RAMs on CNEs with their associated PTDF factors form the so-called FB constraints:

$$PTDF \cdot NP \leq RAM$$

In general, the RAMs will be positive and the flows on the CNEs, induced by the net positions that are optimized by the market coupling mechanism, will be restricted by those values. It may however happen that a certain CNE is pre-congested (already congested before the actual allocation). In this case the Fref' exceeds the Fmax-FRM-FAV value resulting in a negative RAM. In the case that a negative RAM is provided to the market coupling algorithm, the market is enforced to relieve that congestion irrespective of the market preferences. In the example below, the constraint enforces the induced flow on the CNE to be -10 or smaller (e.g. -15).

Example of negative RAM: $PTDFa*N(A) + PTDFb*NP(B) + PTDFc*NP(C) \leq -10$

The market coupling mechanism will find the most efficient way of relieving the congestion.

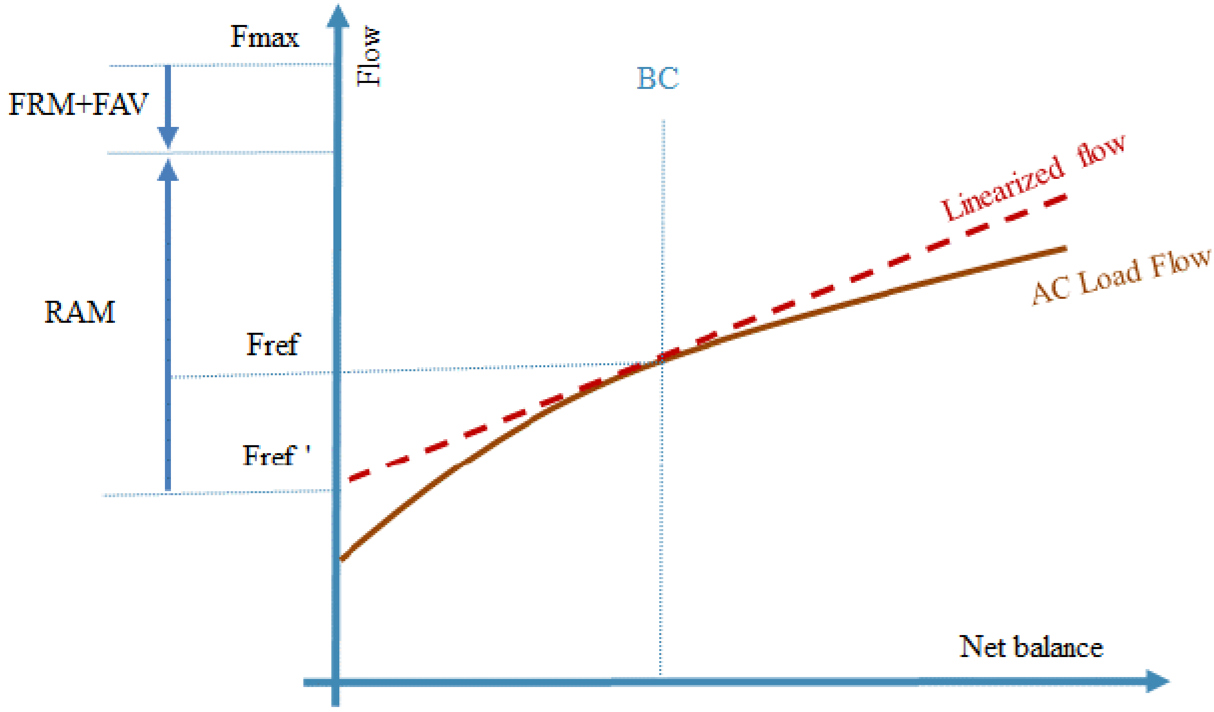

Figure 10-4: Relation between flow, net position and RAM

10.4.4 Input Data

<u>For The FB parameter calculation (or capacity calculation). the basic input data is a Common Grid Model, the constraints to be monitored (CNEs) and the GSK strategy.</u>

10.4.4.1 Grid Model

The Common Grid Model (CGM) is based on Individual Grid Models (IGM) from each of the countries/TSOs inv. All the IGMs for the synchronous area are merged to form the CGM.

- **Grid Representation**

Each of the IGMs has a detailed description of the national grid and its related interconnection nodes, and a more coarse representation of the neighboring grids. In the CGM, we need the detailed view of the total national grids in order to produce accurate FB parameters.

Each IGM are based on forecasts of the real-live operation from snapshots by the national SCADA created from each TSO. In these models are included updates of the expected topology-, load- and generation changes in order to represent the day of operation (day D) for each system in the form of an IGM.

Each IGM contains information about grid topology (how the network elements are connected in the power system at a particular voltage level at a particular point in time) and the net positions of all the nodes in the system at the same point in time. This information is sufficient for doing an AC load flow in order to obtain the resulting flows on all network elements.

The merging procedure of the IGMs implies that all network elements have to be uniquely defined across the IGMs in order to be correctly recognized and represented in the merged CGM. The information contained in the models together with the AC load flow calculation is sufficient to calculate the FB parameters.

❖ **Base Case**

The individual national forecasts to be used for day "D" are normally retrieved from an earlier complete day (e.g. "D-2").

This includes updates of:

- Planned outages
- Load forecasts
- Production forecasts

The first component "planned outages" is vital information for the grid topology of day "D". Outage planning takes place ahead in time, so this information is normally known one week in advance of day "D" and is fairly easy to predict.

Load forecasting is done on a regular basis at each of the TSOs and should also be fairly easily retrieved. Accurate production forecasts are more difficult to retrieve, particularly in a system with large amounts of intermittent power like wind and photovoltaic. But the existence of intermittent generation itself signifies the importance of production forecasting. Large shifts in uncontrollable generation like wind and run-of-river hydro can occur quickly with changes in wind and weather conditions, and will have a significant influence on the geographical distribution of power generation.

10.4.4.2 FB Constraints

Large-scale power systems are normally run under what is referred to as the N-1 security criterion. The criterion states that the power system has to be able to stay within grid security limits after the loss of any one (1) component. To monitor that the system is N-1 stable, the TSO uses a list of possible contingencies and monitors certain grid elements to see if they exceed a certain threshold. These monitored grid elements will be referred to as a critical network element (CNE) and the contingency, applied when monitoring the CNE, will be referred to as a critical outage (CO).

The FB capacity calculation has been developed to monitor violations of steady-state limitations. There are a variety of such limitations but the main factor is the thermal capacity of a single component in the power system such as a line, circuit breaker, disconnector, current transformer and so on. Other examples of possible limitations are the minimum/maximum net position of an area in order to enforce enough reactive power capacity, frequency control capability, short circuit management or inertia.

10.4.5 Flow Reliability Margin

The fundamental element in managing uncertainty in capacity calculation is the reliability margin (Flow Reliability Margin, FRM). Due to uncertainties, the power system operator cannot predict precisely what flow, either active or reactive, will be realized on each CNE. The flow may be larger or smaller than anticipated, but if the flow turns out larger, there may be an overload on a CNE. In order to reduce the probability of physical overloads, some of the capacity on a CNE will be retained from the market as an FRM.

The FRM is based on historical registration of the difference between the power flow of a CNE forecasted two days ahead of time and the actual flow. The FRM, being expressed in MWs, will be different for each CNE but could be based on the same percentile of the statistical distribution of the difference between forecasted and actual power flow.

The origin of the uncertainty involved in the capacity calculation process for the day-ahead market comes from phenomena like approximations within the FB and CNTC methodology (e.g. GSK and capacity used by reactive power). This uncertainty must be quantified and discounted for in the allocation process, in order to prevent that on day D the TSOs will be confronted with flows that exceed the maximum allowed flows of their grid elements. Therefore, for each CNE, a Flow Reliability Margin (FRM) has to be defined, that quantifies at least how the before-mentioned uncertainty impacts the flow on the CNE. Inevitably, the FRM reduces the remaining available margin (RAM) on the CNEs because a part of this free space that is provided to the market to facilitate cross-border trading must be reserved to cope with these uncertainties. The approach for determining the FRM value is illustrated in Figure 10-5.

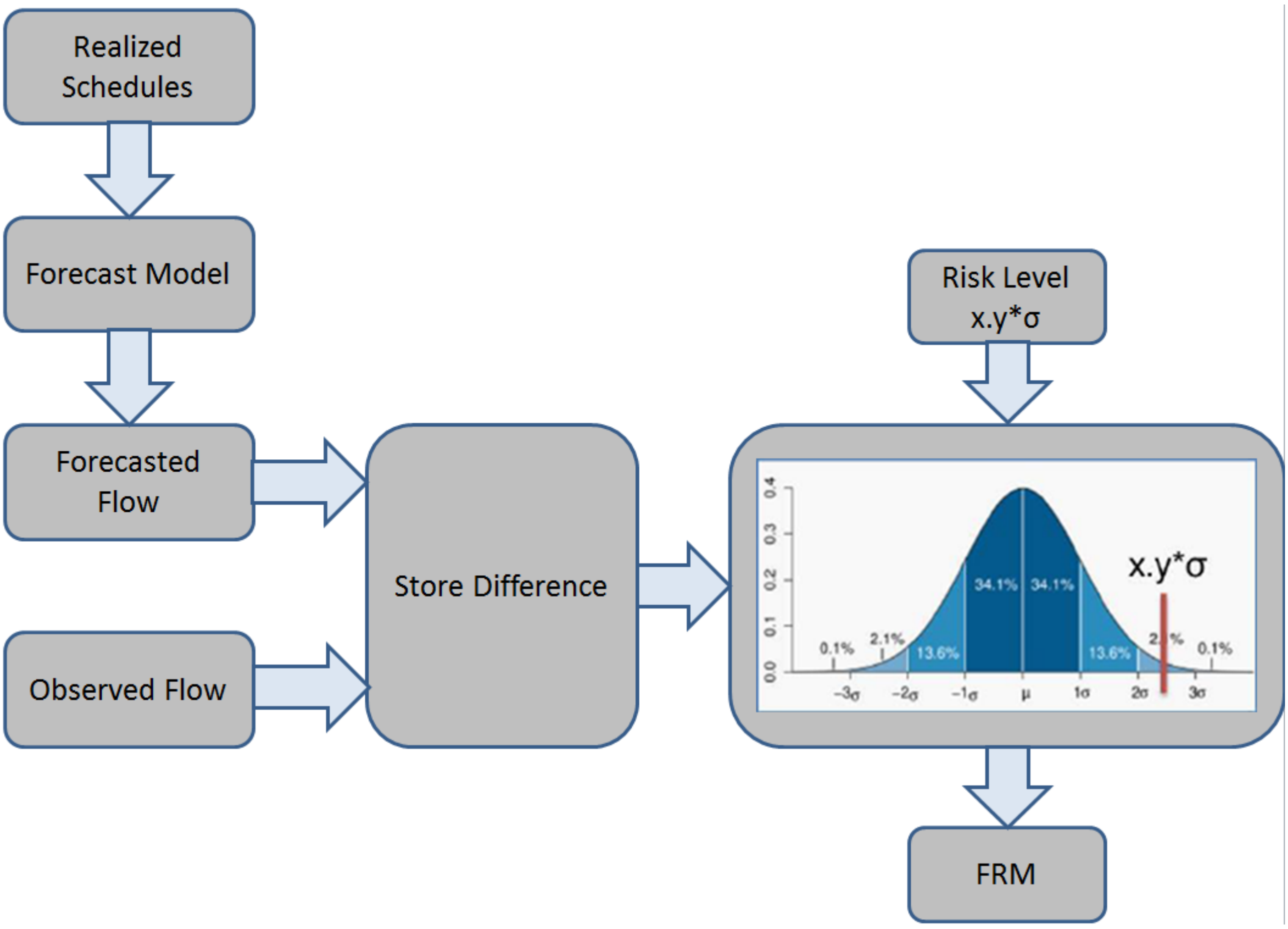

Figure 10-5: Determination of FRM

The basic idea behind the FRM determination is to quantify the uncertainty, by comparing the forecasted flow of the FB model with the observed flow of the corresponding timestamp in real time. More precisely, the calculated PTDFs for day D are used to calculate the flows in the real day D market result. These flows are then compared to the flows in the snap shot of day D.

In order to compare the observed flows from the snapshot with the predicted flows in a coherent way, the FB model is adjusted with the realized schedules corresponding to the instant of time that the snapshot was created. In this way, the same net positions are taken into account when comparing the forecast flows with the observed ones (e.g. Intraday trade is reflected in the observed flows and need to be reflected in the predicted flows as well for fair comparison).

The differences between the observations and predictions are stored in order to build up a database that allows the TSOs to make a statistical analysis on a significant amount of data. Based on a predefined risk level, the FRM values can be computed from the distribution of flow differences between forecast and observation.

By following this approach, the subsequent effects are covered by the FRM analysis:

- Unintentional flow deviations due to operation of load-frequency controls
- Internal trade in each bidding area (i.e. working point of the linear model)
- Uncertainty in Load and generation forecasts
- Assumptions inherent in the Generation Shift Key (GSK)
- Application of a linear grid model, constant voltage profile and reactive power

The structure of the FRM analysis is shown in Figure 10-6.

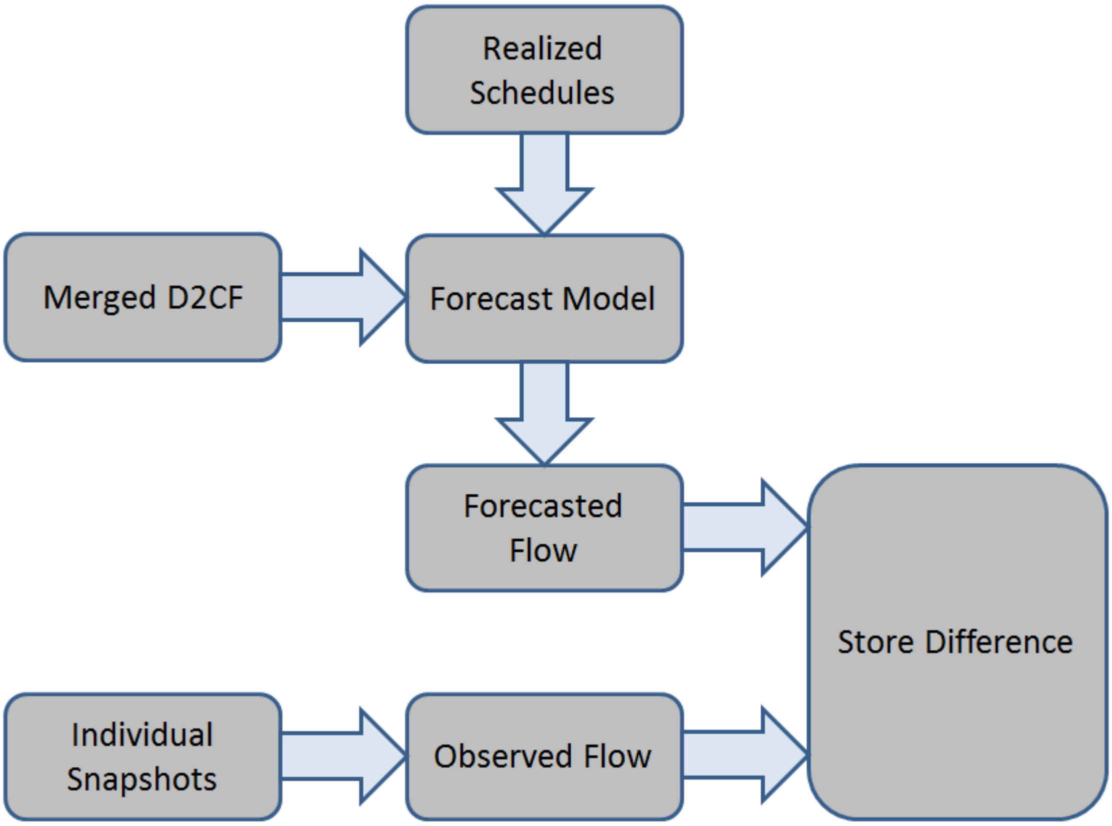

Figure 10-6: Structure of the FRM Calculation

10.4.6 Flow Reliability Margin for N-1 Cases

As CNEs are monitored both under N conditions and N-1 conditions, the question arises whether the FRM value assessed under N conditions is representative for N-1 conditions as well. In case N-1 FRM values need to be assessed, the structure depicted above needs to be changed slightly as indicated in Figure 10-7.

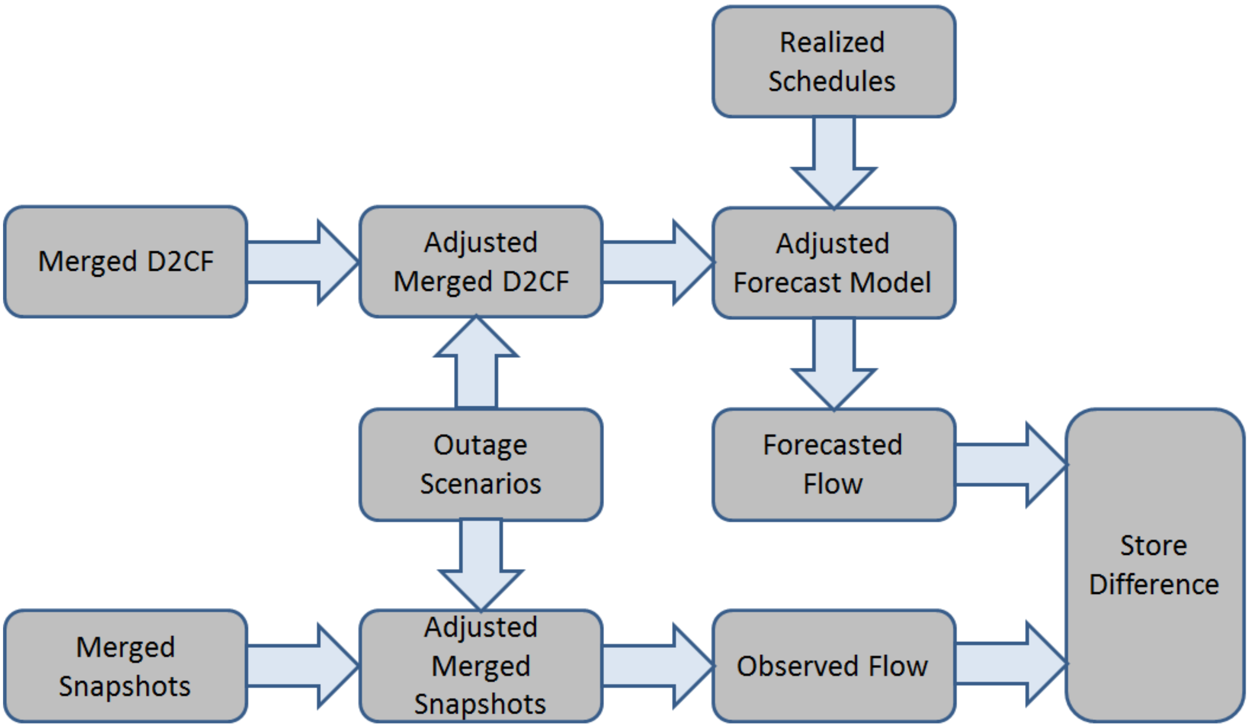

Figure 10-7: Structure of the FRM Calculation under N-1 Conditions

Indeed, where the assessment of the N FRM values is based on a comparison between realized flows and the predicted flows, i.e. observation versus simulation, the N-1 FRM analysis boils down to a comparison between two simulations.

10.5 Notation used in this Annex

ij	Transmission line index from bus *i* to bus *j*, it is also used for interconnected transmission lines
x_{ij}	Reactance of transmission line *ij*
F_{ij}	Active power flow of transmission line *ij*
N_b	Total number of system buses
$\boldsymbol{P}$	Vector of generating units' active power output
$\tilde{\boldsymbol{P}}$	Vector of generating units' active power output, not containing the element corresponding to the reference bus
$\boldsymbol{D}$	Vector of active power demand at the buses
$\tilde{\boldsymbol{D}}$	Vector of active power demand at the buses, not containing the element corresponding to the reference bus

$\boldsymbol{\theta}$	Phase vector of bus voltages
$\bar{\boldsymbol{\theta}}$	Phase vector of bus voltages, not containing the element corresponding to the reference bus
θ_{ref}	Phase of the reference bus voltage
$\boldsymbol{B}$	$N_b \cdot N_b$ system conductivity matrix (imaginary part only) containing the line and column corresponding to the reference bus
$\bar{\boldsymbol{B}}$	$(N_b - 1) \cdot (N_b - 1)$ system conductivity matrix (imaginary part only) not containing the line and column corresponding to the reference bus
$\boldsymbol{B}_G$	$N_b \cdot N_b$ system conductivity matrix (imaginary part only) containing the line and column corresponding to the reference bus, but with high conductivity (ground) to the diagonal element corresponding to the reference bus
$\boldsymbol{Y}$	$N_b \cdot N_b$ inverse matrix of the system conductivity matrix
k	Index of iterations of decentralized algorithms
$\boldsymbol{e}_i$	Vector with value of 1 in transmission line *i* and 0 in all other transmission lines
$\boldsymbol{e}_{ij}$	Vector with value of 1 in transmission line *i*, -1 in transmission line *j* and 0 in all other transmission lines, $\boldsymbol{e}_{ij} = \boldsymbol{e}_i - \boldsymbol{e}_j$

11 Annex B: Day-Ahead Market matching process

This Annex presents a detailed analysis of the PCR Market Coupling Algorithm named "Euphemia", based on its public description[19]. The aim of this Annex is to briefly present the way in which this algorithm maximizes the total market value of the Day-Ahead Auction while taking into account the market and network constraints. Furthermore, additional requirements concerning this algorithm are presented.

11.1 Euphemia Algorithm

EUPHEMIA is the algorithm that has been developed to solve the Day-Ahead European Market Coupling problem. EUPHEMIA matches energy demand and supply for all the periods of a single day at once while taking into account the market and network constraints. **The main objective of EUPHEMIA is to maximize the social welfare, i.e. the total market value of the Day-Ahead auction expressed as a function of the consumer surplus, the supplier surplus, and the congestion rent including tariff rates on interconnectors if they are present**. EUPHEMIA returns the market clearing prices, the matched volumes, and the net position of each bidding area as well as the flow through the interconnectors. It also returns the selection of block, complex, merit, and PUN[20] orders that will be executed. For curtailable blocks the selection status will indicate the accepted percentage for each block.

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[19] Price Coupling of Regions, EUPHEMIA Public Description, December 2016. Available online via the following link:

https://www.nordpoolspot.com/globalassets/download-center/pcr/euphemia-public-documentation.pdf

[20] Merit orders are individual step orders defined at a given period for which is associated a so-called merit order number. A merit order number is unique per period and order type (Demand; Supply; PUN) and is used for ranking merit orders in the bidding areas containing this order type. The lower the merit order number, the higher the priority for acceptance. More precisely, when, within an uncongested set of adjacent bidding areas, several merit orders have a price that is equal to the market clearing price, the merit order with the lowest merit order number should be accepted first unless constrained by other network conditions.

PUN orders are a particular type of demand merit orders. They differ from classical demand merit orders in such sense that they are cleared at the PUN price (weighted average zonal price within a country, i.e. Italy) rather than the bidding area market clearing price (i.e. a PUN order with an offered price lower than market clearing price of its associated bidding area, but higher than PUN price would be fully accepted by EUPHEMIA).

By ignoring the particular requirements of the block, complex, merit and PUN orders, the market coupling problem resolves into a much simpler problem which can be modeled as a Quadratic Program (QP) and solved using commercial off-the-shelf solvers. However, the presence of these orders renders the problem more complex. Indeed, the “kill-or-fill” property of block orders and the minimum income condition (MIC) of complex orders requires the introduction of binary (i.e. 0/1) variables. Moreover, the strict consecutiveness requirement of merit and PUN orders adds up to the complexity of the problem.

In order to solve this problem, EUPHEMIA runs a combinatorial optimization process based on the modeling of the market coupling problem. EUPHEMIA aims to solve a welfare maximization problem (also referred to as the master problem) and three interdependent sub-problems, namely the price determination subproblem, the PUN search sub-problem and the volume indeterminacy subproblem.

In the welfare maximization problem, EUPHEMIA searches among the set of solutions (solution space) for a good selection of block and MIC orders that maximizes the social welfare. In this problem, the PUN and merit orders requirements are not enforced. Once an integer solution has been found for this problem, EUPHEMIA moves on to determine the market clearing prices.

The objective of the price determination subproblem is to determine, for each bidding area, the appropriate market clearing price while ensuring that no block and complex MIC orders are paradoxically accepted and that the flows price-network requirements are respected. If a feasible solution can be found for the price determination sub-problem, EUPHEMIA proceeds with the PUN search subproblem. However, if the sub-problem does not have any solution, we can conclude that the block and complex orders selection is not acceptable, and the integer solution to the welfare maximization problem must be rejected. This is achieved by adding a cut to the welfare maximization problem that renders its current solution infeasible. Subsequently, EUPHEMIA resumes the welfare maximization problem searching for a new integer solution for the problem.

The objective of the PUN search sub-problem is to find valid PUN volumes and prices for each period of the day while satisfying the PUN imbalance constraint and enforcing the strong consecutiveness of accepted PUN orders. When the PUN search sub-problem is completed, EUPHEMIA verifies that the obtained PUN solution does not introduce any paradoxically accepted block/complex orders. If some orders become paradoxically accepted, a new cut is introduced to the welfare maximization problem that renders the current solution infeasible. Otherwise, EUPHEMIA proceeds with the lifting of volume indeterminacies.

In the previous sub-problems, the algorithm has determined the market clearing prices for each bidding area, the PUN prices and volumes for the area with PUN orders, and a selection of block and complex MIC orders that are simultaneously feasible. However, there might exist multiple solutions with respect to the aggregated hourly volumes, net positions, and flows that are coherent with these prices yielding the same welfare. Among all these possible solutions, EUPHEMIA pays special attention to the price-taking orders; it enforces the merit order number and it maximizes the traded volume.

11.1.1 Welfare Maximization Problem (Master Problem)

As mentioned previously, the objective of this problem is to maximize the social welfare, i.e. the total market value of the Day-Ahead auction. The social welfare is computed as the sum of the consumer surplus, the supplier surplus, and the congestion rent. The latter takes into account the presence of tariff rates for the flows through defined interconnectors. In case there is the risk of a curtailment situation in an area where Flow Based constraints apply, a special penalty is applied in the objective function for the non-acceptance of price taking demand. The selection of this penalty function is critically important and reflects policy considerations with respect to the priority of enforcement of the interconnection constraints compared to other constraints. This is linked to the curtailment sharing rules.

EUPHEMIA ensures that the returned results are consistent with the following constraints:

- The acceptance criteria for aggregated hourly demand and supply curves and merit orders
- The fill-or-kill requirement of block orders
- The scheduled stop, load gradient, and minimum income condition of complex orders
- The capacities and ramping constraints imposed on the ATC interconnectors while taking into account the losses and the tariff rates if applicable.
- The flow limitation through some critical elements of the network for bidding areas managed by the flow-based network model. All bidding areas should be balanced: the net position equals the total export minus the total imports for this area, and this should match the area's imbalance: the difference between total matched supply and total matched demand.
- The hourly and daily net position ramping should be respected;

It should be noted that the strict consecutiveness requirement of merit and PUN orders is not enforced in this problem. In other words, the merit orders are considered in this problem as aggregated hourly orders while, the PUN orders are just ignored. **The main difficulty of the welfare maximization problem resides in selecting the block/MIC orders that are to be accepted and those to be rejected. The particularity of the block and MIC orders lies in the fact that they require the introduction of 0/1 variables in order to model their acceptance (0: rejected order, 1: accepted order). The discrete nature of these decision variables is referred to as the integrality**

constraint. The solution of this problem requires some decision variables to be integer (0/1) and the overall problem can be modeled as a Mixed-Integer Quadratic Program (MIQP).

A possible approach to solve such an MIQP problem is to use the branch-and- cut method. The branch-and-cut method is a very efficient technique for solving a wide variety of integer programming problems. It involves running a branch-and-bound algorithm and using cutting planes to tighten the QP relaxations. In the sequel, we will describe how the branch-and-cut method can be adapted to our particular welfare maximization problem and how cutting planes will be generated in the subsequent sub-problems in order to reduce the number and range of solutions to investigate.

11.1.1.1 Overview

EUPHEMIA starts by solving the initial MIQP problem where none of the variables is restricted to be integer. The resulting problem is called the integer relaxation of the original MIQP problem. For instance, relaxing the fill-or-kill constraint, i.e. the integrality constraint on the acceptance of the block orders, is equivalent to allowing all the block orders to be partially executed.

Because the integer relaxation is less constrained than the original problem, but still aims at maximizing social welfare, it always gives an upper bound on attainable social welfare. Moreover, it may happen that the solution of the relaxed problem satisfies all the integrality constraints even though these constraints were not explicitly imposed. The obtained result is thus feasible with respect to the initial problem and we can stop our computation: we got the best feasible solution of our MIQP problem. Note that this is rarely the case and the solution of the integer relaxation contains very often many fractional numbers assigned to variables that should be integer values.

11.1.1.2 Branching

In order to move towards a solution where all the constraints, including the integrality constraints, are met, EUPHEMIA will pick a variable that is violating its integrality constraint in the relaxed problem and will construct two new instances as following:

- The first instance is identical to the relaxed problem where the selected variable is forced to be smaller than the integer part of its current fractional value. In the case of 0/1 variables, the selected variable will be set to 0. This will correspond, for instance, to the case where the block order will be rejected in the final coupling solution.

- The second instance is identical to the relaxed problem where the selected variable is forced to be larger than the integer part of its current fractional value. In the case of 0/1 variables, the selected variable will be set to 1. This will correspond, for instance, to the case where the block order will be accepted in the final coupling solution.

Duplicating the initial problem into two new (more restricted) instances is referred to as branching. Exploring the solution space using the branching method will result in a tree structure where the created problem instances are referred to as the nodes of the tree. For each created node, the algorithm tries to solve the relaxed problem and branches again on other variables if necessary. It should be highlighted that by solving the relaxed problem at each of the nodes of the tree and taking the best result, we have also solved the initial problem (i.e. the problem in which none of the variables is restricted to be integer).

11.1.1.3 Fathoming

Expanding the search tree all the way till the end is termed as fathoming. During the fathoming operation, it is possible to identify some nodes that do not need to be investigated further. These nodes are either pruned or terminated in the tree which will considerably reduce the number of instances to be investigated. For instance, when solving the relaxed problem at a certain node of the search tree, it may happen that the solution at the current node satisfies all the integrality restrictions of the original MIQP problem. We can thus conclude that we have found an integer solution that still needs to be proved feasible. This can be achieved by verifying that there exist valid market clearing prices for each bidding area that are coherent with the market constraints. For this purpose, EUPHEMIA moves on to the price determination sub-problem. If the latter sub-problem finds a valid solution for the current set of blocks/complex orders, we can conclude that the integer solution just found is feasible. Consequently, it is not required to branch anymore on this node as the subsequent nodes will not provide higher social welfares. Otherwise, if no valid solution could be found for the price determination sub-problem, we can conclude that the current block and complex order selection is unacceptable. Thus, a new instance of the welfare maximization problem is created where additional constraints are added to the welfare maximization problem that renders the previous integer solution infeasible.

Let us denote the best feasible integer solution found at any point in the search as the incumbent. At the start of the search, we have no incumbent. If the integer feasible solution that we have just found has a better objective function value than the current incumbent (or if we have no incumbent), then we record this solution as the new incumbent, along with its objective function value. Otherwise, no incumbent update is necessary and we simply prune the node.

Alternatively, it may happen that the branch, that we just added and led to the current node, has added a restriction that made the QP relaxation infeasible. Obviously, if this node contains no feasible solution to the QP relaxation, then it contains no integer feasible solution for the original MIQP problem. Thus, it is not necessary to further branch on this node and the current node can be pruned.

Similarly, once we have found an incumbent, the objective value of this incumbent is a valid lower bound on the social welfare of our welfare maximization problem. In other words, we do not have to accept any integer solution that will yield a solution of a lower welfare. Consequently, if the solution of the relaxed problem at a given node of the search tree has a smaller welfare than that of the incumbent, it is not necessary to further branch on this node and the current node can be pruned.

11.1.1.4 Cutting

Introducing cutting planes is the other most important contributor of a branch-and-cut algorithm. The basic idea of cutting planes (also known as "cuts") is to progressively tighten the formulation by removing undesirable solutions. Unlike the branching method, introducing cutting planes creates a single new instance of the problem. Furthermore, adding such constraints (cuts) judiciously can have an important beneficial effect on the solution process.

As just stated, whenever EUPHEMIA finds a new integer solution with a better social welfare than the incumbent solution, it moves on to the price determination sub-problem and subsequent sub-problems. If in these subproblems, we find out that the sub-problem is infeasible, we can conclude that the current block and complex order selection is unacceptable. Thus, the integer solution of the welfare maximization problem must be rejected. To do so, specific local cuts are added to the welfare maximization problem that renders the current selection of block and complex orders infeasible. Different types of cutting planes can be introduced according to the violated requirement that should be enforced in the final solution. For instance, if at the end of the price determination sub-problem, a block order is paradoxically accepted, the proposed cutting plane will force some block orders to be rejected so that the prices will change and will eventually make the block order no longer paradoxically accepted. Further types of cutting planes will be introduced in the subsequent sub-problems.

11.1.1.5 Stopping Criteria

Euphemia stops in case:

- A time limit is reached;
- The full branch and bound tree is explored;

In case the time limit is reached, but no valid solution is found, the calculation continues and stops only when a first solution is found.

A second time limit applies for finding this first solution: if it times out the session fails and Euphemia does not return any solution.

11.1.2 Price Determination Sub-Problem

In the master problem, EUPHEMIA determines an integer solution with a given selection of block and complex orders. In addition, EUPHEMIA also determines the matched volume of merit and aggregated hourly orders. In this sub-problem, EUPHEMIA must check whether there exist market clearing prices that are consistent with this solution while still satisfying the market requirements. More precisely,

EUPHEMIA must ensure that the returned results satisfy the following constraints:

The market clearing price of a given bidding area at a specific period of the day is consistent with the offered prices of the demand orders and the desired prices of the supply orders in this particular market.

The market clearing price of a bidding area is compatible with the minimum and maximum price bounds fixed for this particular market.

However, the solution of this price determination sub-problem is not straightforward because of the constraints preventing the paradoxical acceptance of block and MIC orders, or preventing the presence of nonintuitive FB results. Indeed, whenever EUPHEMIA deems that the price determination sub-problem is infeasible, it will investigate the cause of infeasibility and a specific type of cutting plane will be added to the welfare maximization problem aiming at enforcing compliance with the corresponding requirement. This cutting plane will discard the current selection of block and complex orders.

- In order to prevent the paradoxical acceptance of block orders, the introduced cutting plane will reject some block orders that are in-the-money. Special attention will be paid when generating these cuts in order to prevent rejecting deep-in-the money orders.

- In order to prevent the acceptance of complex orders that do not satisfy their minimum income condition, the introduced cutting plane will reject the complex orders that will most likely not fulfill their minimum income condition.

- When the market coupling problem at hand features both block and complex orders, EUPHEMIA associates both cutting strategies in a combined cutting plane.

Cuts will also be generated under the following circumstances:

- Furthermore, if the bilateral intuitiveness mode is selected for the flow based model, the prices obtained at the end of the price determination sub-problem must satisfy an additional requirement. This requirement states that there cannot be adverse flows, i.e. flows exporting out of more expensive markets to cheaper ones. If the intuitiveness property is not satisfied, appropriate cutting planes are added as well to the welfare maximization problem.

- In the presence of losses in a situation where a market clears at a negative price bi-directional flows may occur: energy is send back and forth between two areas only to pick up losses.

  Algorithmically this makes sense: when a market clears at a negative price, it is willing to pay for destroying energy (e.g. through losses). However physically it is nonsensical: energy can only be scheduled in one direction. To avoid this situation Euphemia will generate a cut forcing one or the other flow to be zero.

Branch-and-Cut Example

Here is a small example of the execution of the Branch-and-Cut algorithm (Figure 11-1).

At the start of the algorithm, we do not have an incumbent solution. EUPHEMIA first solves the relaxed welfare maximization problem where all the integrality constraints have been relaxed (Instance A). Let us assume that the solution of this problem has a social welfare equal to 3500 but has two fractional decision variables related to the acceptance of the block orders ID_23 and ID_54. At this stage, we can conclude that the upper bound on the attainable social welfare is equal to 3500.

Next, EUPHEMIA will pick a variable that is violating its integrality constraint (block order ID_23, for instance) and will branch on this variable. Thus, two new instances are constructed: Instance B where the block order ID_23 is rejected (associated variable set to 0) and Instance C where the block order ID_23 is accepted (associated variable set to 1). Then, EUPHEMIA will select one node that is not yet investigated and will solve the relaxed problem at that node. For example, let us assume that EUPHEMIA selects Instance B to solve and finds a solution where all the variables associated with the acceptance of block and complex orders are integral with a social welfare equal to 3050. Furthermore, we assume that the price determination sub-problem was successful and that a valid solution could be obtained. We can conclude that the solution of Instance B is thus feasible and can be marked as the incumbent solution of the problem. In addition, the obtained social welfare is a lower bound on any achievable welfare and it is not necessary to further branch on this node.

EUPHEMIA continues exploring the solution space and selects Instance C to solve. Let us assume that an integer solution was found with a social welfare equal to 3440. As the obtained social welfare is higher than that of the incumbent, EUPHEMIA moves on to the price determination subproblem but let us assume that no valid market clearing prices could be found for this sub-problem. In this case, a local cut will be introduced to the welfare maximization problem. More precisely, an instance D is created identical to instance C where an additional constraint is added to render the current selection of block and complex orders infeasible. At this stage, we can conclude that the upper bound on the attainable social welfare is equal to 3440.

Now, let us assume that when solving the instance D of the problem, we get a solution with a social welfare equal to 3300 and a fractional decision variable related to the acceptance of the block order ID_30. As carried out previously, we need to branch on this variable. Thus, two new instances are constructed: Instance E where the block order ID_30 is rejected (associated variable set to 0) and Instance F where the block order ID_30 is accepted (associated variable set to 1). After solving the relaxed problem of Instance E, we assume that the obtained solution is integer with a social welfare equal to 3200. This social welfare is higher than that of the incumbent, so we try to solve the price determination sub-problem. We assume that the price determination sub-problem has a valid solution. Thus, the current solution for Instance E is feasible and is set as the new incumbent solution. We note that the lower bound on any achievable social welfare is now equal to 3200.

Similarly, after solving the relaxed problem of Instance F, we assume that the obtained solution has a social welfare equal to 3100 along with some fractional decision variables. As this solution has a lower social welfare than that of the incumbent, there is no need to further branch on this node and the current node can be pruned.

Figure 11-1 shows the search tree associated with our example.

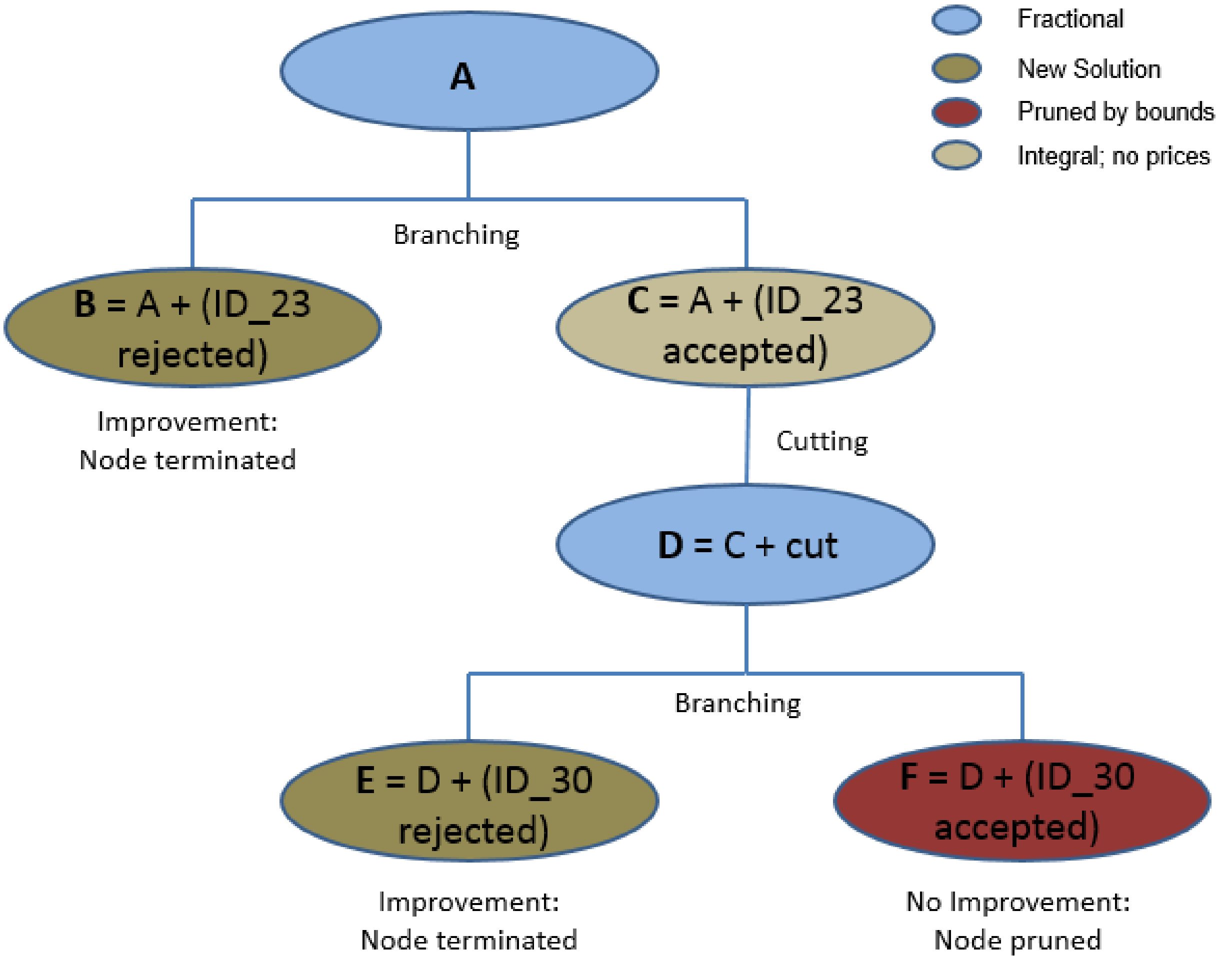

Figure 11-1: Branch-and-Cut Example

11.1.3 PUN Search Sub-Problem

In order to avoid paradoxically accepted PUN orders, PUN cannot be calculated as ex post weighted average of market price, but it must definitely be determined in an iterative process. Consider the following example:

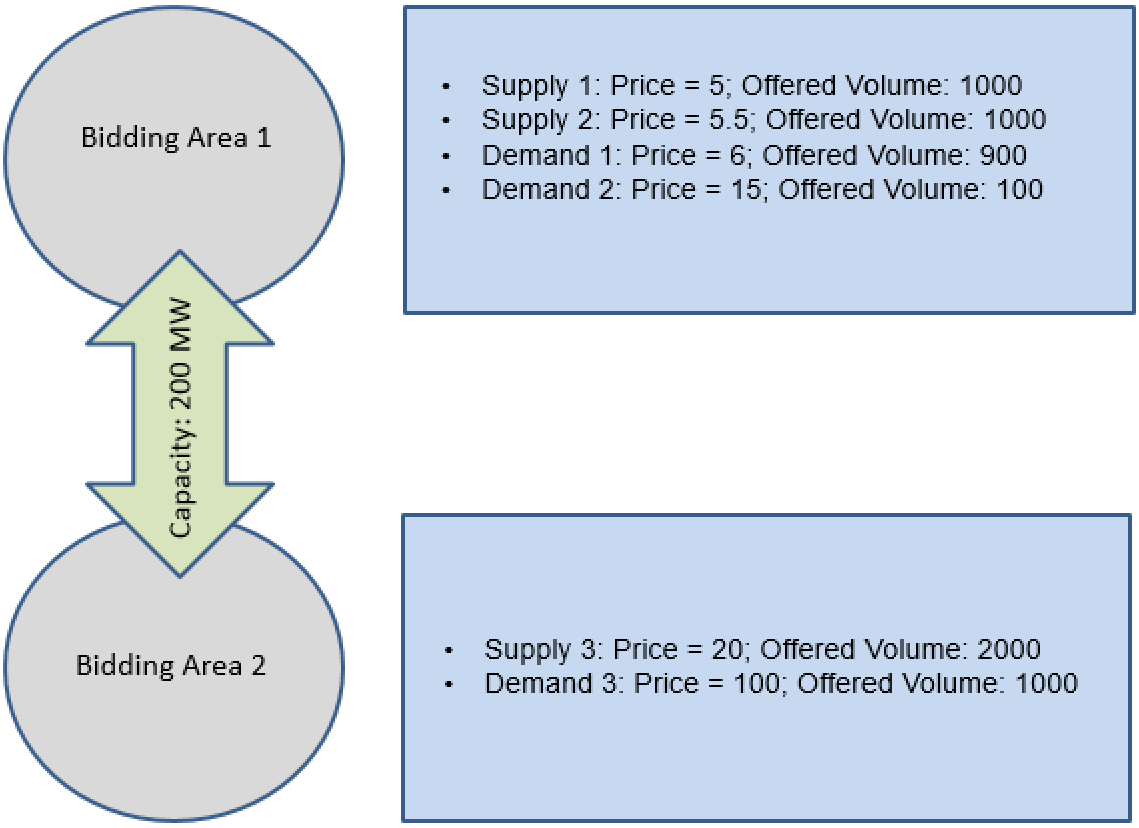

Figure 11-2: PUN Acceptance

If in Figure 11-2, Demand 1, Demand 2 and Demand 3 Orders were “simple” demand merit orders, then the market results would be:

- Bidding area 1:
  - Market clearing price: 5.5 €/MWh;
  - Executed Supply Volume: 1000 MWh;
  - Executed Demand Volume: 1000 MWh.
- Bidding area 2:
  - Market clearing price: 20 €/MWh;
  - Executed Supply Volume: 1000 MWh;
  - Executed Demand Volume: 1000 MWh.

If Demand 1, Demand 2 and Demand 3 Orders were "PUN" demand merit orders, then this solution is not acceptable. In fact, given a PUN imbalance tolerance=0, PUN calculated as weighted average will be:

$$[(1000 * 5.5) + (1000 * 20)] / 2000 = 12.75 \text{ €/MWh.}$$

In this case, order Demand 1 would be paradoxically accepted.

Through an iterative process, the final solution will be the following:

- Market clearing price of Bidding area 1: 5 €/MWh;
- Market clearing price of Bidding area 2: 20 €/MWh;
- PUN price: 20 €/MWh;
- Supply order Supply 1: partially accepted (200 MWh);
- Supply order Supply 2: fully rejected;
- Supply order Supply 3: partially accepted (800 MWh)
- Demand orders Demand 1 and Demand 2: fully rejected;
- Demand order Demand 3: fully accepted;
- Flow from Bidding area 1 to Bidding area 2: 200 MWh;
- Imbalance: (1000 * 20) – (1000 * 20) = 0;
- Welfare: (1000 * 100) – [(200 * 5 + 800 * 20)] = 83000 €;

The PUN search is launched as soon as a first candidate solution has been found at the end of the price determination sub-problem (activity 1 in Figure 11-3). This first candidate solution respects all PCR requirements but PUN. The objective of the PUN search is to find, for each period, valid PUN volumes and prices (activity 2 in Figure 11-3) while satisfying the PUN imbalance constraint and enforcing the strong consecutiveness of accepted PUN orders.

If the solution found for all periods of the day, is compatible with the solution of the master problem (activity 3 in Figure 11-3), it means that a solution is found after PRMIC reinsertion (see next section) has been performed. Otherwise, the process will resume calculating, for each period, new valid PUN volumes and prices to apply to PUN Merit orders.

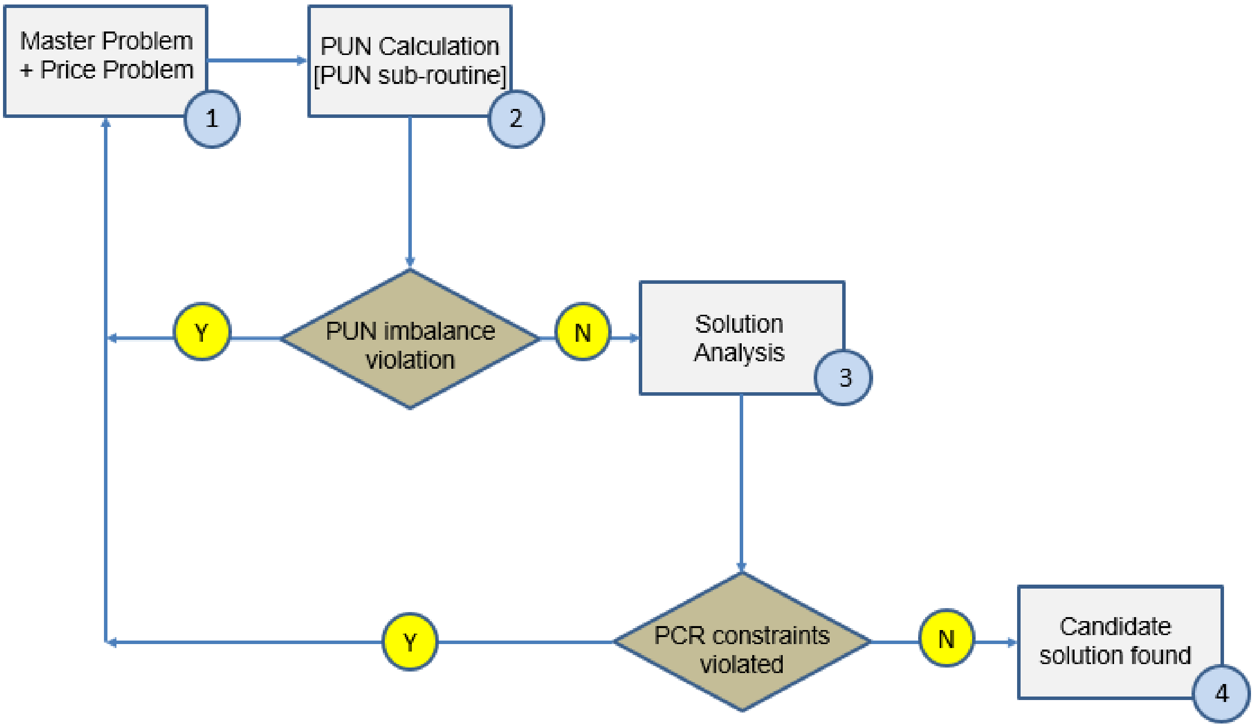

Figure 11-3: PUN Search Sub-problem Process

The PUN search is essentially an hourly sub-problem where the requirements are defined on an hourly basis, in which:

- Strong consecutiveness of PUN order acceptance is granted: a PUN order at a lower price cannot be satisfied until PUN orders at higher price are fully accepted
- PUN imbalance is within accepted tolerances.

For a given period, the selected strategy consists in selecting the maximum PUN volume (negative imbalance), and then trying to select smaller volumes until a feasible solution is found that minimizes the PUN imbalance.

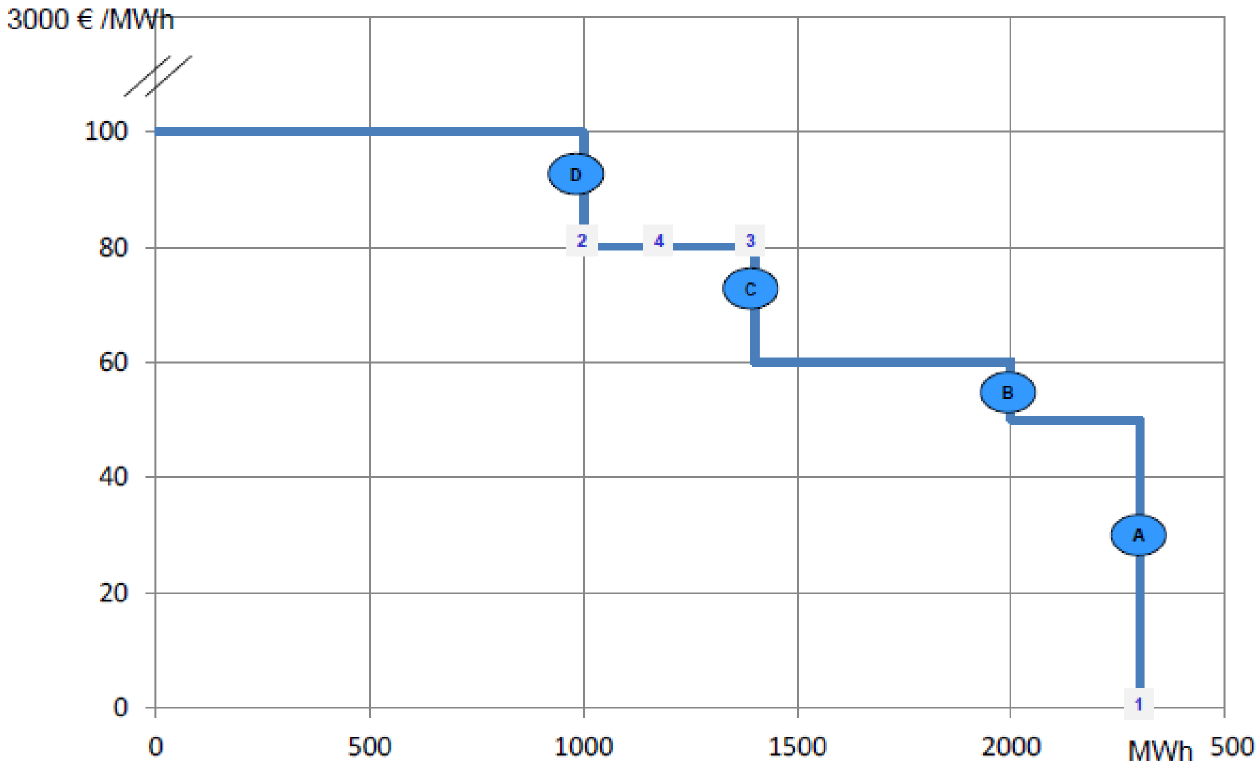

Figure 11-4: PUN Hourly Curve

EUPHEMIA starts by calculating the PUN imbalance associated with the maximum accepted PUN volume (negative imbalance expected[21]; point 1 in Figure 11-4). If the PUN imbalance associated with the maximum PUN doesn't violate PUN imbalance tolerance, a candidate solution is found.

On the contrary, EUPHEMIA calculates the price which minimizes PUN imbalance (in Figure 11-4, analysis on vertical segment A) while the volume is fixed to the maximum accepted PUN volume. If the PUN imbalance calculated in this way is within the PUN imbalance tolerance interval, a candidate solution is found. If not, the next vertical segment (i.e. in Figure 11-4, vertical segment B), will be analyzed. This process is repeated until between 2 consecutive vertical segments, a change in sign of PUN imbalance is found (i.e. in Figure 11-4, positive PUN Imbalance in segment D; and negative PUN Imbalance in segment C). In this case, EUPHEMIA fixes the price (i.e. in Figure 11-4, the horizontal segment between point 2 and 3, to which corresponds a price of 80 €/MWh), and tries to minimize the PUN imbalance, using the volume as decision variable.

[21] PUN consumers paid 0, producers receive market prices. Unless all market prices are equal to 0, imbalance will be negative

If the PUN imbalance calculated in this step is compatible with PUN imbalance tolerance, a candidate solution is found. If not, Euphemia continues the search on the horizontal segment (i.e. considering in Figure 11-4, let point 4 the one associated with PUN imbalance minimization at the price of 80 €/MWh. If in point 4, the imbalance is positive and greater than positive PUN imbalance tolerance, search will be continued in the interval between [4;3]; If in point 4, the imbalance is negative and less than negative PUN imbalance tolerance, the search will be continued in the interval between [2;4]).

As soon as PUN search is completed, EUPHEMIA verifies that the obtained PUN solution does not introduce any paradoxically accepted block orders or violates any other PCR constraints. If some block orders become paradoxically accepted or some other constrains are violated, a new cut is introduced to the welfare maximization problem that renders its current solution infeasible. Otherwise, EUPHEMIA proceeds with the PRMIC reinsertion.

11.1.4 PRMIC Reinsertion

Finally, if the PUN sub-problem is successful, the solution returned by Euphemia should be made free of any false paradoxically rejected complex MIC order (PRMIC). Thus, once the market clearing prices have been found, Euphemia proceeds with an iterative procedure aiming to verify that all the rejected complex MIC orders, that are in-the-money, cannot be accepted in the final solution. For this purpose, Euphemia first determines the list of false PRMIC candidates. Then, Euphemia goes through the list, takes each complex MIC order from this list, activates it, and re-executes the price determination sub-problem. Two possible outcomes are expected:

If the price computation succeeds and the social welfare was not degraded, we can conclude that the PRMIC reinsertion was successful. In this case, a new list of false PRMIC candidates is generated and the PRMIC reinsertion module is executed again.

Conversely, if the price determination sub-problem is infeasible, or the social welfare is reduced, the complex MIC order candidate is simply considered as a true PRMIC, and the algorithm picks the next false PRMIC candidate. It should be noted that this case will not result to add a new cutting plane to the welfare maximization problem.

The PRMIC reinsertion module execution is repeated until no false PRMIC candidate remains. At this stage, we have obtained a feasible integer selection of block and complex orders along with coherent market clearing prices for all markets.

11.1.5 PRB Reinsertion

In much the same way as the PRMIC reinsertion procedure, a module is in charge of reinserting PRBs after a fully valid solution has been found in the Branch-and-Bound tree.

This local search approach helps reduce the number of PRBs, and usually leads quickly to a new solution, with a better welfare.

As soon as a solution has been stored, a local search algorithm tries to find neighbor solutions where some PRBs are newly activated. The MICs selection is fixed for this step. Of course, just like the PRMICs, not all PRBs may be reactivated. Some of them, when they are reinserted, change the prices in such a way that the solution is not valid anymore. They are true PRBs.

The procedure for the local search stops for each neighbor type when either one of these criteria is met:

- The list of candidates neighbors is empty. In this case, a local search for the next neighbor type is started or the local search stops if all neighbor types were already considered.
- The time limit is getting too close: based on historical performance 3 minutes is required for the remaining sub-problems

After selecting a neighbor solution, it is possible that a new PUN search is needed. The newly activated and deactivated blocks may indeed have invalidated the PUN results, since the imbalance is not enforced by a constraint in this module, contrary to what is done in the PRMIC reinsertion module. In any case, the PRMIC reinsertion procedure and the volume problems are then run to obtain a second fully valid solution.

Like the false PRMIC reinsertion module, this module allows EUPHEMIA to bypass the branch and cut mechanism, by taking a ”shortcut” in the tree. The welfare of the new solution will be used as a cut-off value to prune other nodes. Note that the local search module is only applied once at each node where a valid solution is found. After that, the search is resumed in the Branch-and-Bound tree.

A heuristic approach is used at multiple levels in the local search procedure:

We have to restrict the neighborhood in our search. Thus, we consider only single orders. However, a combination of orders can sometimes lead to better solutions and it can be impossible to reach those solutions via this local search.

The candidate neighbors are given in a certain order. By choosing to reactivate the orders according to this criterion, EUPHEMIA might miss other combinations of activations leading to a solution.

If the price computation fails, no cuts are added. We assume that the reinsertion of the order makes the prices problem infeasible and therefore reject it.

11.1.5.1 Volume Indeterminacy Sub-Problem

With calculated prices and a selection of accepted block, MIC and PUN orders that provide together a feasible solution to market coupling problem, there still might be several matched volumes, net positions and flows coherent with these prices. Among them, EUPHEMIA must select one according to the volume indeterminacy rules, the curtailment rules, the merit order rules and the flow indeterminacy rules. These rules are implemented by solving five closely related optimization problems:

- Curtailment minimization
- Curtailment sharing
    - Partially addressed via the curtailment mitigation in the welfare definition;
- Volume maximization
- Merit order indeterminacy
- Flow indeterminacy

11.1.5.2 Curtailment Minimization

A bidding area is said to be in a curtailment condition when the market clearing price is at the maximum or the minimum allowed price of that bidding area and the submitted quantity at these extreme prices is not fully accepted. The curtailment ratio is the proportion of price-taking orders which are not accepted. All orders have to be submitted within a (technical) price range set in the respective bidding area. Hourly supply orders at the minimum price of this range and hourly demand orders at the maximum price of this range are interpreted as price-taking orders, indicating that the member is willing to sell/buy the quantity irrespective of the market clearing price.

The first step aims at minimizing the curtailment of these price-taking limit orders, i.e. minimizing the rejected quantity of price-taking orders. **More precisely, EUPHEMIA enforces local matching of price-taking hourly orders with hourly orders from the opposite stack in the same bidding area as a counterpart.** Hence, whenever curtailment of price-taking orders can be avoided locally on an hourly basis – i.e. the curves cross each other - then it is also avoided in the final results. This can be interpreted as an additional constraint setting a lower bound on the accepted price-taking quantity (see Figure 11-5 where the dotted line indicates the minimum of price-taking supply quantity to be accepted).

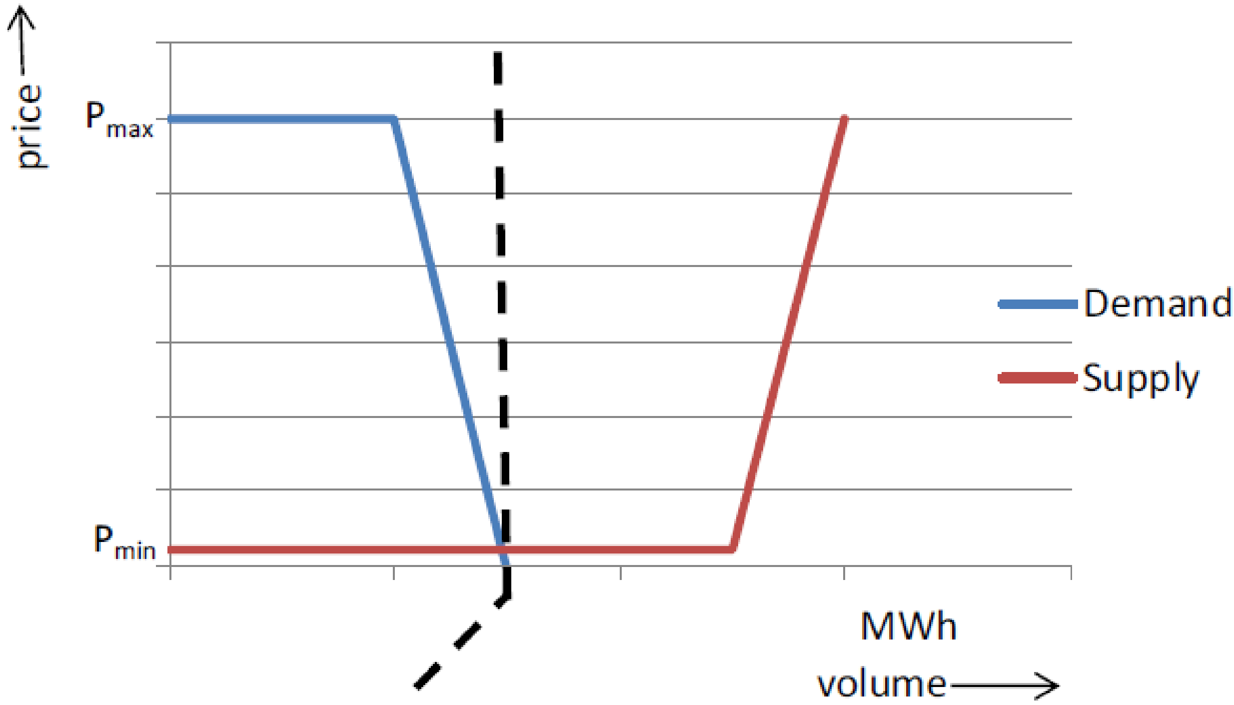

Figure 11-5: Dotted line indicates the minimum of (price-taking) supply volume to be accepted

This constraint is referred to as the LOCAL_MATCHING constraint, and it is active in the master problem, i.e. prior to the price- and volume- coupling problems, but as an additional constraint to the welfare maximization problem.

11.1.5.3 Curtailment Sharing

The aim of curtailment sharing is to equalize as much as possible the curtailment ratios between those bidding areas that are simultaneously in a curtailment situation, and that are configured to share curtailment.

This curtailment sharing is implemented in part in the master problem and in part in the curtailment sharing volume problem step.

Curtailment Sharing – Master Problem

The objective function of the master problem is to maximize welfare. For an ATC line this results in a situation where areas that are not in curtailment will export to areas that are in curtailment.

However, under the FB model this is not necessarily the case: if an exchange from area A to area B results in a higher usage of the capacity compared to an exchange A to C it is possible that is more beneficial to exchange from A to C, whereas market B is in curtailment. This is referred to as “flow factor competition”.

In order to prevent such cases on demand side (effectively treating curtailment outside of the welfare maximizing framework) we penalize the non-acceptance of price-taking demand orders (or PTDOs) by adding to the primal objective:

$$M \cdot \sum_{z} Q_z^{PTDO} \left(1 - x_z^{PTDO}\right)^2$$

where:

x_z^{PTDO}	the acceptance ratio of the price taking order of area z (and $1 - x_z^{PTDO}$ consequently the non-acceptance ratio)
Q_z^{PTDO}	the volume of the PTDO of area z
M	a large value

This expression is added to the welfare. If the value of M is sufficiently large, it will help minimize the rejected price-taking quantity in all markets, before looking for a solution with a good welfare. The quadratic penalty function will tend to harmonize the curtailment ratios across the curtailed markets if any.

Curtailment sharing volume problem

For the case where areas were not affected by “flow factor competition”, i.e. under ATC market coupling, curtailment sharing is targeted in the volume problem. Provided ATC capacity remains, the welfare function is indifferent between accepting price taking orders of one bidding area or another.

This step aims to equalize curtailment ratios as much as possible among bidding areas willing to share curtailment. Bidding areas that are not willing to share curtailment will have their curtailment fixed in the welfare maximizing solution where the LOCAL_MATCHING constraint prevented these areas to be forced to share curtailments. At the same time the LOCAL_MATCHING constraint of adjacent areas prevented non-sharing areas to receive support from sharing areas. The supply or demand orders within a bidding area being in curtailment at maximum (minimum) price are shared with other bidding areas in curtailment at maximum (minimum) price. For those markets that share curtailment, if they are curtailed to a different degree, the markets with the least severe curtailment (by comparison) would help the others reducing their curtailment, so that all the bidding areas in curtailment will end up with more equal curtailment ratios while respecting all network constraints.

The curtailment sharing is implemented by solving a dedicated volume problem, where all network constraints are enforced, but only the acceptance of the price taking volume is considered in the objective function. The curtailment ratios weighted by the volumes of price taking orders is minimized:

$$\min \sum_{h} \sum_{\substack{m: \\ m \in C_{h,Demand}}} \sum_{\substack{o: \\ market\ (o)=m \\ P_o = P_{min\ ,m}}} |q_0|(1 - ACCEPT_0)^2 + \sum_{h} \sum_{\substack{m: \\ m \in C_{h,Demand}}} \sum_{\substack{o: \\ market\ (o)=m \\ P_o = P_{max\ ,m}}} |q_0|(1 - ACCEPT_0)^2$$

One can prove that for optimal solutions for this problem in the absence of any active network constraints this will result into equal curtailment ratios.

11.1.5.4 Maximizing Accepted Volumes

In this step, the algorithm maximizes the accepted volume. All hourly orders, complex hourly sub-orders, merit orders and PUN orders are taken into account for maximizing the accepted volumes. The acceptance of most orders is already fixed at this point. Either because it is completely below or above the market clearing price, or it is a price-taking order fixed at the first or second volume indeterminacy subproblem (curtailment minimization or curtailment sharing). Block orders are not considered in this optimization because a feasible solution has been found prior to this step in the master problem.

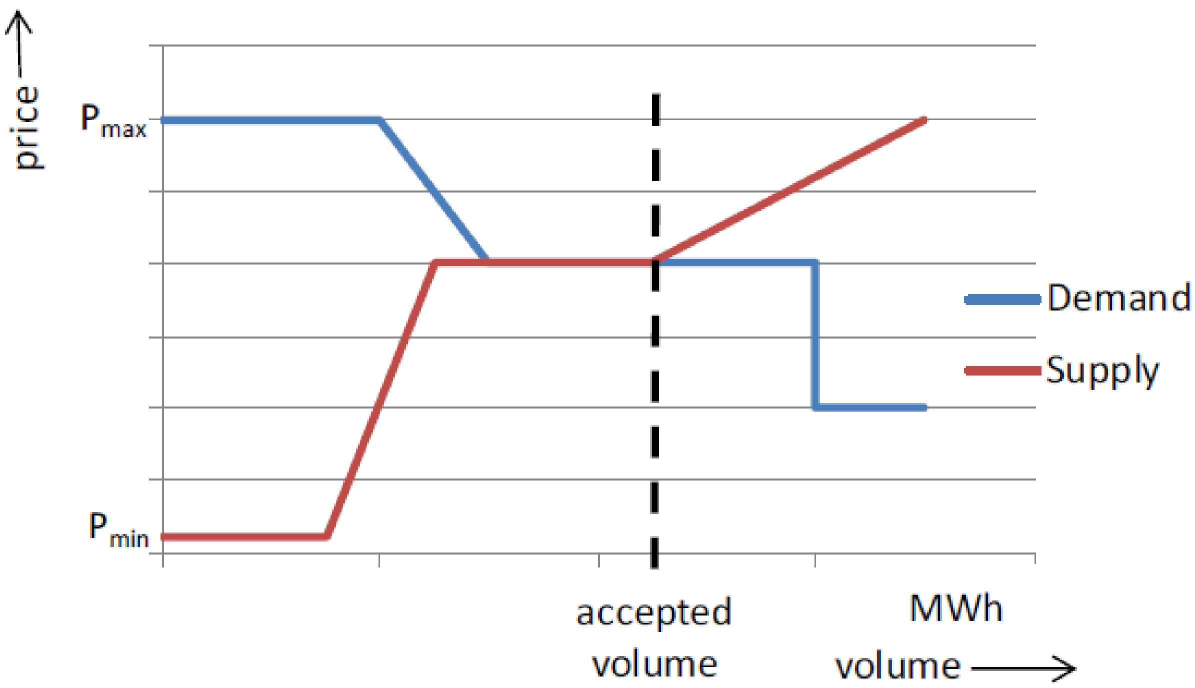

Figure 11-6: The accepted volume is maximized

11.1.5.5 Merit Order Enforcement

This step enforces merit order numbers of the hourly orders if applicable. The acceptance of hourly orders with merit order numbers at-the-money is relaxed and re-distributed according to their acceptance priority. This problem is solved only if the solution found satisfies the PUN requirements (after the PUN search) or if there are no PUN orders but there exist some merit orders.

11.1.5.6 Flow Indeterminacy

The last sub-problem re-attributes flows on the ATC lines based on the linear and quadratic cost coefficients of these lines. Apart from the flows, all other variables are fixed to their predetermined value. This step can only affect the results in situations where there is full price convergence within a meshed network, allowing multiple flow assignments to result in identical net positions. By using specific values for the cost coefficients, certain routes will be chosen and unique flows will be determined.

11.2 Additional Requirements

11.2.1 Precision and Rounding

EUPHEMIA provides results (unrounded) which satisfy all constraints with a target tolerance. These prices and volumes (flows and net positions) are rounded by applying the commercial rounding (round-half-up) convention before being published.

11.2.2 Properties of the solution

During the execution of EUPHEMIA, several feasible solutions can be found. However, only the solution with the highest welfare value (complying to all network and market requirements) found before the stopping criterion of the algorithm is met is reported as the final solution.

It should be noted that for difficult instances some heuristics[22] are used by EUPHEMIA in its execution. Thus, it cannot be expected that the "optimal" solution is found in all cases.

[22] In mathematical optimization, a **heuristic** is a technique designed for solving a problem more quickly when classic methods are too slow, or for finding an approximate solution when classic methods fail to find any exact solution. This is achieved by trading optimality, completeness, accuracy, and/or precision for speed (Ref-: http://en.wikipedia.org/wiki/Heuristic_(computer_science)).

11.2.3 Stopping Criteria

As an optimization algorithm, EUPHEMIA searches the solution space for the best feasible solution until some stopping criterion is met. The solution space is defined as the set of solutions that satisfy all the constraints of the problem.

EUPHEMIA is tuned to provide a first feasible solution as fast as possible. However, after finding the first solution, EUPHEMIA continues searching, the solution space for a better solution until a stopping criterion for example the maximum time limit of 10 minutes, is reached or until no more feasible selection of blocks and MIC orders exists.

Additional stopping criteria have also been implemented in the algorithm and can be used. The calculation will stop when one of these criteria is reached:

- **TIME LIMIT**

  This parameter sets a limit to the total running time of EUPHEMIA. However, since the time taken by operations after calculation (e.g. writing of the solution in the database) can be variable, this is an approximate value.

- **ITERATION LIMIT**

  EUPHEMIA can stop after it has processed a given number of nodes.

- **SOLUTION LIMIT**

  EUPHEMIA can stop after it has found a given number of solutions (regardless of their quality).

11.2.4 Transparency

EUPHEMIA produces feasible solutions and chooses the best one according to the agreed criterion (welfare-maximization). Therefore, the chosen results are well explainable to the Participants: published solution is the one for which the market value is the largest while respecting all the market rules.

11.2.5 Reproducibility

The reproducibility of an algorithm is defined as the capability of the algorithm to reproduce the same results upon request. On the same machine, two subsequent runs with the same input data should find the same solutions, meaning that the intermediate/final solutions found at iteration ’X’ are the same. In other words, when the stopping criterion is the number of investigated solutions, a reproducible algorithm can guarantee to obtain the same final result when run on the same machine. However, when the stopping criterion is a time limit, a faster computer will allow the algorithm to investigate more solutions than a slower one. In this case, the reproducibility consists in investigating on the faster computer at least the same set of solutions as the ones investigated on the slower computer.

Mind that with the introduction of PRB reinsertion, another time limit is introduced: the PRB reinsertion process times out too, ahead of the final time limit. This should therefore be understood as a time limit in its own right and reproducibility only applies up until this point.

12 Annex C: Categorization of RES and DR resources

12.1 RES units categorization

In most European countries there is a differentiation in the market participation rules of old and new RES units, and there is also a differentiation between small and larger new RES units. Similar differentiations exist also in the recent Greek Law 4414/2016, concerning the new remuneration scheme of RES units in Greece.

Specifically, the following categorization of RES units is valid:

- **1st category: Old RES units with a Power Purchase Agreement (PPA) with LAGIE until 31/12/2015, for which the purchase contract has not been terminated yet, independently of their installed capacity.**

  According to the Law 4414/2016 [10], the RES units with an installed capacity below 5 MWp shall continue to be remunerated with their Feed-in-Tariff (FiT), until the termination of their contract with LAGIE, as stated in Article 3, par. 11 of Law 4414/2016.

  On the contrary, the RES units with an installed capacity above 5 MWp (threshold defined by a Ministerial Decision) have two options:

  a) either to continue to be remunerated with their FiT, until the termination of their contract with LAGIE, as stated in Article 3, par. 11 of Law 4414/2016,

  b) or to sign a Contract for Differential State Aid Support with LAGIE, in which case they shall be remunerated with:

     - the wholesale market prices, depending on the market they sell their production, and
     - an additional fee derived by the sliding Feed-in-Premium (FiP) mechanism, and considering their existing FiT price, as stated in Article 3, par. 13 of Law 4414/2016.

  In case of RES units with an installed capacity below 5 MWp and in case (a) above, the TSO shall be responsible for the injection forecasting (in all individual markets) for such RES units, the RES and CHP Units Registry Operator shall be responsible for the submission of the respective price-taking energy offers in the markets (Day-Ahead Market and possibly Intra-Day Market). The relevant imbalance costs, in this case, shall be transferred to an uplift account (as it is currently the case in Greece), which shall be fully covered by the Load Representatives (pro-rata to their represented load).

In case (b) above, the respective RES operator (RES Producer, RES Aggregator, or Last Resort Aggregator) shall be responsible for the RES units' forecasting and bidding in the markets, and shall bear, where the case may be, their balance responsibility (according to the Imbalance Settlement mechanism).

- **2nd category: Old RES units with a Power Purchase Agreement (PPA) with LAGIE until 31/12/2015, for which the purchase contract has terminated, independently of their installed capacity.**

The market participation of such units has not been decided yet by the Ministry of Environment and Energy; such decision is expected to be taken in the near future.

Under this category RES units which proceed with a renewal of their equipment (repowering), according to par. 22, art. 3 of L. 4414/2016, can be included. These units may have the right to sign a Contract for Differential State Aid Support with the LAGIE so that they acquire a Feed-in-Premium.

The RES units that do not fall under the provisions regarding renewal of their equipment (repowering) shall be remunerated with the wholesale market prices, depending on where they sell their production (namely, to be remunerated with the Day-Ahead Market price for the sold energy in the Day-Ahead Market, and with the Intra-Day Market price, i.e. "selling price" in case of Continuous Trading, for the sold energy in the Intra-Day Market). These RES units shall not have any rights for remuneration through a sliding FiP.

Such RES units shall fully enter in the wholesale market, namely the respective RES operators (RES Producers, RES Aggregators, or the Last Resort Aggregator) shall be responsible for their injection forecasting and bidding in the markets, and shall bear, where the case may be, their full balance responsibility.

- **3rd category: New RES units, that have the right to enter to a contract agreement with LAGIE (refers to projects that conclude this process after the 1st January 2016), with the aid granted either through an auctioning process or not, but with an installed capacity up to 3 MWp[23] for wind plants and up to 500 kWp[23] for all other RES categories (hereinafter called "small new RES units")**

These RES units have currently only the following option:

a) to sign a Fixed Price Power Purchase Agreement with LAGIE (in accordance with the provisions of Article 3 par. 5 of Law 4414/2016), thus hereinafter called "small new RES units under FiT", in which case they will be remunerated with:
   - either the Reference Price of Article 4 of Law 4414/2016,

[23] Thresholds that can be amended (lowered) by a Ministerial Decision.

- or the auction offer price in case the aid is granted through an auctioning process, according to Article 7 par. 4 of Law 4414/2016,

At a later stage and upon the operation of the new electricity market model these RES units could also have the following option:

b) to sign a Contract for Differential State Aid Support with LAGIE[24], thus hereinafter called "small new RES units under FiP", in which case they shall be remunerated with:

- the wholesale market prices, depending on the market they sell their production, and
- an additional fee derived by the sliding FiP mechanism, while considering the Reference Price stated in Article 4 of Law 4414/2016.

For RES units of case (a) ("small new RES units under FiT"), the TSO shall be responsible for their injection forecasting (in all individual markets), the RES and CHP Units Registry Operator shall be responsible for the submission of the respective price-taking energy offers in the markets (Day-Ahead Market and possibly Intra-Day Market). The relevant imbalance costs, in this case, shall be transferred to an uplift account (as discussed above).

For RES units of case (b), whenever this becomes active, ("small new RES units under FiP"), the RES operator (RES Producer, RES Aggregator, or Last Resort Aggregator) shall be responsible for their forecasting and bidding in the markets, and shall bear, where the case may be, their balance responsibility (according to the Imbalance Settlement mechanism applying in categories 4 and 5 below, regarding larger new RES units).

➢ **4th category: New RES units, with a Contract for Differential State Aid Support with LAGIE within year 2016 (or, in any case, before the commencement of the auctioning processes for the granting of new aid, as discussed in the 5th category), but with an installed capacity above 3 MWp for wind plants and above 500 kWp for all other RES categories (hereinafter called "larger new RES units").**

These RES units, having signed a Contract for Differential State Aid Support with LAGIE, shall be remunerated:

a) with the wholesale market prices, depending on the market they sell their production, and

b) with an additional fee derived by the sliding FiP mechanism, while considering the Reference Price stated in Article 4 of Law 4414/2016.

[24] Most probably through a RES Aggregator.

The Participants responsible for these RES units (RES operators) are either the RES Producers, or the RES Aggregators (contracted appropriately with the RES Producers), or the Last Resort Aggregator (according to the Law 4414/2016).

Concerning the balance responsibility for these RES units ("larger new RES units"), a Transitory Mechanism for the Optimal Forecasting Accuracy (hereinafter "TMOFA") shall be activated. According to TMOFA, the respective RES operators shall be penalized (at the monthly Imbalance Settlement process) in case of high deviations of the forecasted injections (offered energy quantity at the Day-Ahead Market) and the actual injections. The accuracy of the forecasted injections also affects (increases) the "management fee" to be given to these RES operators during the validity period of the TMOFA. The TMOFA is not applicable for RES units represented by the Last Resort Aggregator.

The TMOFA shall be active until the implementation of a liquid Intra-Day Market in Greece, under the provisions of the Target Model. Then, the TMOFA shall be terminated (along with the "management fee" given to the RES operators) and the RES operators shall have full balance responsibilities (same as the balancing rules for the conventional units) for the RES units they represent, according to the provisions of the Imbalance Settlement process.

- **5th category: New RES units, which have been granted aid through an auction, having signed a Sliding FiP Contract for Differential State Aid Support with LAGIE, and with an installed capacity above 3 MWp for wind plants and above 500 kWp for all other RES categories (included in the group called "larger new RES units").**

  These RES units, having signed a Sliding FiP Contract for Differential State Aid Supportwith LAGIE, shall be remunerated:

  a) with the wholesale market prices, depending on the market they sell their production, and

  b) with an additional fee derived by the sliding FiP mechanism, while considering their offered price in the auctioning process (according to Article 7 par. 4 of Law 4414/2016).

  The Participants responsible for these RES units (RES operators) are either the RES Producers, or the RES Aggregators (contracted appropriately with the RES Producers), or the Last Resort Aggregator (according to the Law 4414/2016).

  Concerning their balance responsibility, the same rules with the 4th category of RES units applies. However, no "management fee" is provided to such RES operators.

It should be noted that the above categories refer exclusively to RES units connected at the Greek interconnected power system. The respective status and categories for non-interconnected islands are different, since special rules are valid for such RES units under the Greek Law 4414/2016.

In this context, a 6th category can also be included in the above analysis, concerning new RES units that shall be connected at a non-interconnected island, which shall be afterwards connected with the Greek interconnected power system. Upon such interconnection, the same remuneration scheme and market rules (as they are valid in the interconnected system) shall apply for these RES units.

12.2 RES units categorization in terms of market participation

Considering the above categories of RES units, the broader RES groups that can be defined in terms of market participation are as follows:

- **1st group (RES FiT Portfolios):** This group includes RES units' categories 1 (except from case (b) in this category) and 3(a) of Section 3.1, aggregated on technology based portfolios (RES FiT Portfolios), for which (independently of the remuneration scheme in each separate case) the TSO shall be responsible for the injection forecasting (in all individual markets), the RES and CHP Units Registry Operator shall be responsible for the submission of the respective price-taking energy offers in the markets (Day-Ahead Market and possibly Intra-Day Market).

  The balancing cost of the RES FiT Portfolio shall be covered pro-rata by all Load Representatives, as is currently the case. This provision shall be presented in the Balancing and Ancillary Services Code.

- **2nd group (RES Units and RES Portfolios):** This group includes RES units' categories 1(b), 2 (depending on the Ministerial Decision, as discussed above), 3(b) (depending whenever this provision becomes active), 4, 5 and 6 of Section 3.1, either on a per-unit basis (RES Units) or aggregated in portfolios (RES Portfolios), for which (independently of the remuneration scheme in each separate case) the RES operators (RES Producers, RES Aggregators, or Last Resort Aggregator) shall be responsible for the injection forecasting and bidding in the wholesale markets. , and shall bear, where the case may be, the foreseen balance responsibility (either through the TMOFA or through the nominal Imbalance Settlement provisions).

Therefore, in the analysis included in this report, the above broader groups of RES units (RES FiT Portfolios, RES Units, RES Portfolios) shall be taken into account and handled appropriately in terms of market design rules.

12.3 DR resources categorization in terms of market participation

There is no provision or special product for DR resources in the Day-Ahead Market. Note, no baseline conditions are relevant with DR in the DAM. The baseline rule is applicable to DR in the Balancing Market providing balancing services to the TSO.

Given their operational and market participation characteristics, as well as existing practices regarding their integration in different European electricity markets, DR resources are categorized as follows:

- **1st category: Based on market areas in which DR resources participate for the purpose of providing Balancing Services.**

  In this respect, DR resources can participate either in the form of Interruptible Loads or directly in the Balancing and Ancillary Services Market. The discriminatory point has to do with the fact that Interruptible Loads (both availability and utilization) are procured by the TSO ahead of time (e.g. on an annual basis) and do not participate in the Balancing and Ancillary Services Market (ISP and RTBM). In this context, the Interruptible Loads are activated in the event that the remaining Balancing Services may not cover the real-time system imbalance needs. (This means that evaluation for activation takes place before real-time.)

  Interruptible Loads concern the simplest / most immature form of DR participation. As more market areas become available for DR integration, Interruptible Loads tend to be replaced by the direct participation of DR resources in the Balancing and Ancillary Services Market, without however being completely abandoned. As such, it is ECCO's recommendation that Interruptible Loads should continue to exist in the new market design in Greece, even after the respective integration of DR resources in other market areas, like the new Balancing and Ancillary Services Market. This is consistent with best market practices worldwide where interruptible loads and tariffs for reliability purposes co-exist with price sensitive DR which directly participates in the market.

- **2nd category: Dispatchable vs. Non-Dispatchable Loads**

  DR loads are considered by default as Dispatchable, in the sense that the load increase or decrease can be performed in real time following a Dispatch Instruction issued by the TSO, subject to their pre-defined technical constraints. For this reason, there are no provisions for the participation of Non- Dispatchable Loads in DR events.

- **3rd category: Aggregated vs. individual (Dispatchable) loads**

  Consumers can offer their load responsiveness to the markets:

  a) either individually, in which case they are designated as **Dispatchable Loads** represented by **Dispatchable Load Operators**,

  b) or by contracting with a **DR Aggregator** (either a third party aggregator, or their Load Representative which assumes the DR Aggregator's responsibilities), in which case they are included in a wider DR Portfolio represented by the DR Aggregator. Most consumers do not have the means to trade directly into the energy markets, because e.g. their individual loads are too small to qualify for such participation. For this reason, they usually require service by a DR

Aggregator, to help them participate in the electricity market and offer them a clearly-defined offer, which is both simple to use and contains clear benefits.

