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European Network of
Transmission System Operators
for Electricity

**Network Code on Capacity Allocation and Congestion Management**

 **Updated Draft Following Consultation**

**16 July 2012**

***Notice***

**This draft document reflects the status of the work of TSO experts as of 16 July 2012, in line with the ACER Framework Guidelines on Capacity Allocation & Congestion Management published on 29 July 2011. It is based on the input received through extensive informal dialogue with stakeholders and the results of a web based consultation held between 23 March and 23 May 2012 and workshops held on the 7 May and 3 July 2012.**

**This document is a work in progress and is provided informally to interested parties to inform their consideration of the way in which the document has evolved in light of responses. Feedback may be provided during stakeholder group meetings scheduled for 7 and 29 August 2012.**

**In compliance with Article 10 of Regulation (EC) No 714/2009, ENTSO-E will adopt its  “Network Code on Capacity Allocation and Congestion Management” and submit it  to ACER on or before 30 September 2012.**

**PURPOSE AND OBJECTIVES**

Having regard to Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC,

Having regard to Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators,

Having regard to Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003,

Having regard to the Congestion Management Guidelines which form an Annex to the Regulation 714/2009,

Having regard to the priority list issued by the European Commission on 22 December 2010,

Having regard to the final framework guideline on Capacity Allocation and Congestion Management issued by the Agency for the Coordination of Energy Regulators on 29 July 2011,

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

Having regard to the Comitology Guideline on Fundamental Electricity Data Transparency being developed in concurrent timescales to this network code,

Having regard to the Comitology Guideline on Governance of Day Ahead and Intraday Market Coupling being developed in concurrent timescales to this network code,

Having regard to the request from the European Commission to develop a network code on Capacity Allocation and Congestion Management in accordance with the ACER framework guideline prior to a date of 30 September 2012 of 16 September 2011.

Whereas:

1. The internal market in electricity, which has been progressively implemented since 1999, aims to deliver real choice for all consumers in the Community, be they citizens or businesses, new business opportunities and more cross-border trade, so as to achieve efficiency gains, competitive prices and higher standards of service, and to contribute to security of supply and sustainability.
2. Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC and Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 underline the need for an increased cooperation and coordination among transmission system operators within a European network of transmission system operators for electricity (ENTSO‐E) to create network codes for providing and managing effective and transparent access to the transmission networks across borders, and to ensure coordinated and sufficiently forward-looking planning and sound technical evolution of the transmission system in the Community, including the creation of interconnection capacities, with due regard to the environment.
3. As stated in Directive 2009/72/EC a well-functioning internal market in electricity should provide producers with the appropriate incentives for investing in new power generation, including in electricity from renewable energy sources, paying special attention to the most isolated countries and regions in the Community’s energy market. A well-functioning market should also provide consumers with adequate measures to promote the more efficient use of energy for which a secure supply of energy is a precondition.
4. The security of energy supply is an essential element of public security and is therefore inherently connected to the efficient functioning of the internal market in electricity and the integration of the isolated electricity markets of Member States. Electricity can reach the citizens of the Union only through the network. Functioning electricity markets and, in particular, the networks and other assets associated with electricity supply are essential for public security, for the competitiveness of the economy and for the well-being of the citizens of the Union.
5. Regulation (EC) 714/2009 states that in order to ensure optimal management of the electricity transmission network and to allow trading and supplying electricity across borders in the Community, a European Network of Transmission System Operators for Electricity (the ENTSO for Electricity), should be established. The tasks of the ENTSO for Electricity should be carried out in compliance with Community competition rules which remain applicable to the decisions of the ENTSO for Electricity. The tasks of the ENTSO for Electricity should be well-defined and its working method should ensure efficiency, transparency and the representative nature of the ENTSO for Electricity. The network codes prepared by the ENTSO for Electricity are not intended to replace the necessary national network codes for non-cross-border issues. Given that more effective progress may be achieved through an approach at regional level, transmission system operators should set up regional structures within the overall cooperation structure, whilst ensuring that results at regional level are compatible with network codes and non-binding ten-year network development plans at Community level. Member States should promote cooperation and monitor the effectiveness of the network at regional level. Cooperation at regional level should be compatible with progress towards a competitive and efficient internal market in electricity.
6. Regulation (EC) No 714/2009 states increased cooperation and coordination among transmission system operators is required to create network codes for providing and managing effective and transparent access to the transmission networks across borders, and to ensure coordinated and sufficiently forward-looking planning and sound technical evolution of the transmission system in the Community, including the creation of interconnection capacities, with due regard to the environment. Those network codes should be in line with framework guidelines, which are non-binding in nature (framework guidelines) and which are developed by the Agency for the Cooperation of Energy Regulators established by Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (the Agency). The Agency will have a role in reviewing, based on matters of fact, draft network codes, including their compliance with the framework guidelines, and it should be enabled to recommend them for adoption by the Commission. The Agency should assess proposed amendments to the network codes and it should be enabled to recommend them for adoption by the Commission. Transmission system operators should operate their networks in accordance with those network codes.
7. According to Article 8 (7) of Regulation (EC) No 714/2009, the network codes shall be developed for cross-border network issues and market integration issues and shall be without prejudice to the Member States’ right to establish national network codes which do not affect cross-border trade.
8. Transmission system operators (TSOs) are according to Directive 2009/72/EC responsible for operating, ensuring the maintenance of and, if necessary, developing the extra high-voltage and high-voltage interconnected system its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity and with a view to its delivery of electricity to final customers or to distributors.
9. ENTSO-E has produced this network code to comply with the requirements of the ACER Capacity Allocation and Congestion Management (CACM) framework guideline published on 29 July 2011. The CACM network code(s) will be applied by electricity transmission system operators taking into account possible public service obligations and without prejudice to the regulatory regime for cross-border issues pursuant to Article 38 of the Electricity Directive and of the responsibilities and powers of national regulatory authorities (NRAs) established according to Article 37 paragraph 6 of the Electricity Directive.
10. This network code sets out clear and objective requirements for transmission system operators, power exchanges and market participants to contribute to non-discrimination, effective competition and the efficient functioning of the internal electricity market.
11. Article 16 of Regulation (EC) No 714/2009 states that the maximum capacity of the interconnections and/or the transmission networks affecting cross‐border flows shall be made available to Market Participants, complying with safety standards of secure network operation and that network congestion problems shall be addressed with non-discriminatory market-based solutions which give efficient economic signals to the market participants and transmission system operators involved.
12. ENTSO-E will ensure consistency with existing and future network codes and, in particular, the Balancing network code and the System Operation network code(s) in view of the need for clear coordination between system operation, balancing and the intraday market is essential.
13. This network code does not address the issues of transparency and information management within the electricity market. These issues are the subjects of dedicated comitology guidelines to be proposed by the European Commission on fundamental electricity data transparency and by the obligations of market participants under REMIT.
14. Common rules are defined for capacity calculation and allocation in the day ahead and intraday timeframes. The allocation of long term interconnection capacity shall be dealt with in a forthcoming forward capacity allocation network code.
15. The network code shall complement and where necessary, amend the existing Congestion Management Guidelines from the Annex to the Regulation 714/2009 and specify detailed aspects which need to be implemented with reference to relevant provisions from these Guidelines.
16. This network code divides up the process steps and responsibilities required for the operation of the pan European electricity market into functional roles. It is the responsibility of Member States to allocate at least one entity to be responsible to perform each functional role, while recognising that these functional roles can be subsequently delegated to third parties by the responsible entity.
17. The existing congestion management guidelines annexed to Regulation 714/2009 require transmission system operators to coordinate capacity calculation methodologies by defining common rules for the allocation of interconnection capacity in the different timeframes.
18. The capacity calculation process covers the day ahead and intraday market timeframes. Capacities will be updated in a timely manner based on latest information through an efficient capacity calculation process.
19. Capacity calculation will be coordinated at least at a regional level to ensure reliable capacity calculation and that optimal capacity is made available to the market. Common regional capacity calculation methodologies will be established to define inputs, calculation approach, remedial actions and validation requirements.
20. There are two permissible approaches when calculating cross zonal capacities: flow based (FB) or coordinated net transmission capacity (NTC). The FB method is preferred over the coordinated NTC method for day ahead and intraday capacity calculation where interdependencies between the interconnections between bidding zones is high. FB should only be introduced after market participants have been consulted and given sufficient preparation time to allow for a smooth transition. The coordinated NTC approach may be applied in regions where interdependencies between cross zonal capacities are low and the added value of FB method cannot be proven.
21. A common grid model representing the European power system, will be established to calculate cross zonal capacities in a coordinated way. The common grid model will include a model of the transmission network and will include the location of generation and load units relevant to cross-zonal capacity calculation. The provision of accurate and timely information by each transmission system operator is essential to the creation of the common grid model.
22. The common grid model will require each transmission system operator to prepare an individual grid model of their system and send it to a European merging function which will combine them into a single common grid model. The individual grid model will include information from generation and load units. This information will include at minimum: technical, availability and scheduling information relevant for transmission system operators to forecast a generation pattern and running order.
23. To ensure reliable capacity calculation and avoid discrimination between internal and cross border transactions, transmission system operators will use a common set of remedial actions to deal with both internal and cross border congestion. Transmission system operators will coordinate the use of remedial actions in capacity calculation to facilitate more effective congestion management.
24. Transmission system operators will implement coordinated cross zonal redispatching or countertrading at least regionally. Cross-zonal redispatching or countertrading shall be coordinated with control area internal redispatching or countertrading. Redispatching or countertrading will be conducted efficiently. The pricing of generation reservation will not distort the market. Transmission system operators will coordinate the conditions for capacity reservations.
25. Bidding zones will be defined to ensure efficient congestion management and overall market efficiency. Bidding zones can be subsequently modified by splitting, merging or adjusting the zone borders. Bidding zones will be consistent across different market timeframes and will be relatively stable across time, while reflecting changing network conditions. Bidding zones will reflect long term transmission system congestions and will take into account adverse effects on neighbouring bidding zones where the underlying cause of these is related to the size of bidding zones.
26. Every two years transmission system operators will submit to national regulatory authorities and the Agency a technical analysis of the current bidding zones based on redispatching/countertrading costs and structural congestions. Based on this analysis, relevant national regulatory authorities and the Agency will evaluate market efficiency and possible market power issues and may initiate a bidding zone review.
27. The objective of bidding zone reviews will be to increase overall market efficiency including all economic, technical and legal aspects of relevance such as socio-economic welfare, liquidity, competition, network structure and topology, planned network reinforcement and redispatching costs.
28. Transmission system operators will allocate capacity in the day-ahead and intraday timeframes using implicit auctions. The operation of implicit auctions relies on effective and timely interfaces between transmission system operators, power exchanges and a series of other parties to ensure capacity is allocated and congestion managed in an efficient manner.
29. Day ahead and intraday capacity is firm, thereby enabling effective cross border allocation and contributing to the objectives of the Regulation 714/2009.
30. Pan European implicit auctions require a pan European price coupling process. This process will respect transmission capacities and allocation constraints and will be designed in a manner to allow application/extension across the entire EU and the development of future new product types.
31. Despite the creation of a robust algorithm and appropriate back up processes, there may be situations where the market coupling process is unable to produce results. Consequently fallback solutions will be required at a national and/or regional level to ensure capacity can still be allocated.
32. Continuous implicit trading will be implemented intraday with reliable pricing of transmission capacity reflecting congestion in case of scarce capacity.
33. Force Majeure is defined, as required by the ACER framework guideline of 29 July 2011 and will be used for all capacity allocation timeframes (forward, day-ahead and intraday markets).
34. Efficiently incurred costs associated with guaranteeing firmness of capacity and the costs of establishing processes to comply with this network code will be recovered via network tariffs or appropriate mechanisms in a timely manner to avoid transmission system operators being exposed to unnecessary financial risks.
35. Transitional arrangements will allow direct explicit access for Intraday capacity via the capacity management module in the absence of Sophisticated Products that meet market needs.

**Title 1**

**GENERAL PROVISIONS**

**Article 1**

**SUBJECT MATTER AND SCOPE**

1. This Network Code sets common rules for Capacity Allocation and managing cross Bidding Zone congestion in the Day Ahead and Intraday timeframe. This will involve the establishment of common methodologies for determining the volumes of capacity simultaneously available between Bidding Zones and methodologies for defining Bidding Zones.
2. The requirements set forth by this Network Code shall apply to Transmission System Operators, National Regulatory Authorities, the Agency, Market Operators, Capacity Traders and all Market Participants active in the Cross Zonal trading of electricity.

**Article 2**

**DEFINITIONS (glossary)**

For the purpose of this Network Code, the following definitions shall apply:

**Allocation/Capacity Allocation** - the attribution of Cross Zonal Capacity. Within the Day Ahead and Intraday market, Capacity Allocation shall refer to implicit allocation (both capacity and energy) unless stated otherwise;

**Agency** – The Agency for the Cooperation of Energy Regulators as established by Regulation (EC) No 713/2009;

**Allocation Constraints -** the constraints as specified by the System Operator that the Matching Algorithm shall respect in both the Day Ahead and Intraday market.  Allocation Constraints may include, (but shall not be limited to): operational security constraints, ramping constraints, transmission losses;

**Bidding Zone** -the largest geographical area within which Market Participants are able to exchange energy without Capacity Allocation. Each generation and load unit shall belong to only one Bidding Zone for each Market Time Period.

**Bidding Zone** **Border -** a set of physical transmission lines linking adjacent Bidding Zones;

**Capacity Calculation Approach** - can be either Flow Based Approach or Coordinated Net Transmission Capacity approach;

**Capacity Calculation Process -** a process in which the capability of the network to accommodate market transactions is assessed, it consists of calculation of the Cross Zonal Capacity. This assessment must be in line with operational security and optimisation of capacity made available to market participants;

**Capacity Calculation Region –** the regions in which regional coordinated capacity calculation shall be applied. A System Operator belongs to a Capacity Calculation Region if a part of its Control Area belongs to a Bidding Zone having its Bidding Zone Border within the Capacity Calculation Region;

**Capacity Management Module** – a module within the pan-European Intraday solution containing and computing up-to-date available Cross-Zonal Capacity in real time and allocating the Cross-Zonal Capacity in a continuous manner;

**Capacity Trader** - the function responsible for submitting, in accordance with the conditions for Explicit Allocation, explicit capacity request for Cross Zonal Capacity during the bidding period and who receives Allocated Capacity via an Explicit Allocation;

**Central Counter Party -** the function of entering into contracts with Market Participants, by novation of the contracts resulting from the Matching process and of organizing the transfer of Net Positions resulting from Capacity Allocation with other Central Counter Parties or Shipping Agents;

**Clearing Price -** the price determined from the highest accepted selling Order and the lowest accepted buying Order;

**Common Grid Model (CGM) –** European-wide or multiple-TSOs-wide data set, created by the TSOs and coordinated within the ENTSO-E, created through merging of relevant data;

**Congestion Income -** the revenues received as a result of capacity allocation in the Day Ahead and Intra Day markets;

**Congestion Income Distributor** - the function of distributing the Congestion Income;

**Control Area -** is a coherent part of a synchronous area, usually coinciding with the territory of a company, a country or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network, operated by a single System Operator;

**Coordinated Capacity Calculator -** the function that calculates Cross Zonal Capacities, at least at a regional level. It also manages the validation process;

**Coordinated Net Transmission Capacity (NTC) -** refers either to a Cross Zonal Capacity or to a capacity calculation methodology based on the principle of assessing and defining ex-ante a maximum energy exchange between adjacent Bidding Zones;

**Costly Remedial Action –** a Remedial Action taken to solve a Physical Congestion with direct payments made to procure the service (as, but not limited to, Countertrading and Redispatching);

**Countertrading -** a Cross Zonal exchange initiated by System Operators between two Bidding Zones to relieve a Physical Congestion;

**Critical Network Element -** a grid element taken into account in the Capacity Calculation Process, limits the amount of power that be exchanged in order to maintain the security of the power system;

**Cross Zonal Capacity -** The capability of the interconnected electricity transmission network to accommodate energy transfer between Bidding Zones. It can be expressed either as NTC value or FB parameters, and takes into account Operational Security Constraints;

**Cross Control Area Remedial Action -** a Remedial Action is said to be Cross Control Area if that action is not fully controlled by the System Operator in charge of the Control Area where the Physical Congestion to be relived is located;

**D-1 -** The day prior to the day D;

**Day Ahead Market –** the market timeframe where commercial transactions are executed the day prior to the day of delivery of traded products;

**Day Ahead Firmness Deadline -** the point in time after which Cross Zonal Capacity becomes firm;

**Day Ahead Market Gate Closure -** the point in time until which Orders are accepted in the Day Ahead Market;

**Economic surplus -** the sum, after having completed a Matching algorithm over all Bidding Zones, of seller surplus (the aggregated difference between the sellers’ willingness to sell and the Clearing Price), buyer surplus (the aggregated difference between buyers’ willingness to pay and the Clearing Price), Congestion Income, and other costs and benefits, where appropriate;

**Emergency Situation** - a situation where the Transmission System Operator must act in an expeditious manner and re-dispatching or Countertrading is not possible as defined by Article 16 of Regulation 714/2009;

**European Merging Function -** the single European function creating the unique Common Grid Models, through the merging of all Individual Grid Models;

**Explicit (Capacity) Allocation -** the allocation of Cross Zonal Capacity only, without the energy transfer;

**Fault -** is a non transient failure of an electrical component or unforeseen risk to safety which requires the element to be taken out of service immediately;

**Financial Risk for System Operators -** is the risk of incurring costs related to physical firmness and financial firmness costs, and costs of using costly remedial actions within the Capacity Calculation Process;

**Firm/Firmness** - arrangements to guarantee that capacity rights remain unchanged once allocated (physical firmness) or compensated in case of curtailment (financial firmness);

**Flow Based or Flow Based Approach -** is a capacity calculation methodology limiting the Cross Zonal exchanges between Bidding Zones directly with the maximum flows on the critical branches of the grid and Power Transfer Distribution Factors;

**Flow Based Parameters -** are the available margins on critical branches with associated Power Transfer Distribution Factors (which estimate the influence of Cross Zonal exchanges between Bidding Zones on grid branches);

**Force Majeure** – for the purpose of application in respect of capacity allocation mechanisms as foreseen in Article 16 of Regulation (EC) N° 714/2009 shall mean any event or situation beyond the reasonable control of a System Operator, and not due to a fault of such System Operator, which cannot be avoided or overcome with reasonable foresight and diligence, which cannot be solved by measures which are from a technical, financial and/or economic point of view, reasonably possible for the System Operator, which as actually happened and is objectively verifiable, and which makes it impossible for such System Operator to fulfil temporarily or definitively, its obligations in accordance with this Network Code;

**Generation Shift Keys (GSK) -** a means of translating a Net Position change of a given Bidding Zone into estimated specific injection increases or decreases in the Common Grid Model;

**Individual Grid Model** **-** a Bidding Zone or multi Bidding Zone wide data set, to be merged with other Individual Grid Model components through the European Merging Function in order to create the Common Grid Model;

**Internal Grid Element -** a grid element which is not on a Bidding Zone Border;

**Intraday Market -** the market timeframe between Intraday Cross Zonal Gate Opening Time and Intraday Cross Zonal Gate Closure, where commercial transactions are executed prior to the delivery of traded products;

**Intraday Cross Zonal Gate Closure Time** **-** the point in time where Cross Zonal Capacity Allocation is no longer permitted for a given Market Time Period. There is one Intraday Cross Zonal Gate Closure Time for each Market Time Period for a given Bidding Zone Border;

**Intraday Cross Zonal Gate Opening Time -** the point in time when Cross Zonal capacity between Bidding Zones is released for a given Market Time Period and a given Bidding Zone Border;

**Intraday Energy Gate Closure Time -** the point in time when energy trading for a Bidding Zone is no longer permitted for a given Market Time Period within the Intraday Market. There is one Intraday Energy Gate Closure Time for each Market Time Period per Bidding Zone. The Intraday Energy Gate Closure Times shall be after or at the same time as the Cross Zonal Intraday Gate Closure Time;

**Intraday Energy Gate Opening Time -** the point in time when energy trading for a Bidding Zone is permitted for a given Market Time Period. There is one Intraday Energy Gate Opening Time for each day of delivery per Bidding Zone. The Intraday Energy Gate Opening Times of at least the Bidding Zones adjacent to a Bidding Zone Border shall be prior or equal to the Intraday Cross Zonal Gate Opening Time of this Bidding Zone Border;

**Market Congestion** - means a situation in which the Economic Surplus has been limited by the Cross Zonal Capacities or other active Allocation Constraints;

**Market Coupling Operator -** the function that Matches Orders for all Bidding Zones, taking into account Allocation Constraints and Cross Zonal Capacities and thereby implicitly allocating capacity for the Day Ahead and Intraday timeframes;

**Market Information Aggregator** **-** the function of aggregating and publishing Day Ahead market information;

**Nominated Electricity Market Operator -** the function that collects and delivers Orders;

**Market Operator –** an entity referring to tasks and operational responsibilities pursuant to the Comitology Guideline on Governance;

**Market Participant -** an entity authorized by a Nominated Electricity Market Operator to submit Orders. For the sake of clarity, TSOs and PXs and their designated entity(ies) can be considered Market Participants while respecting the applicable Regulation;

**Market Time** **-** shall be Central European Summer Time or Central European Time, whichever is in effect. In essence, it is the local time in Brussels;

**Market Time Period -** is the time span(s) for delivery of energy used in the Day Ahead and Intraday Market;

**Matched Orders** - consist of all matched (buy and sell) Orders within a Trade performed by the Matching Algorithm;

**Matching** - the trading mode through which sell Orders are assigned to appropriate buy Orders to ensure the maximization of Economic Surplus;

**Matching Algorithm –** either the Price Coupling Algorithm or Continuous Trading Matching Algorithm;

**National Regulatory Authority** **-** a regulatory authority as referred to in Article 35 (1) of Directive 2009/72/EC;

**Net Position -** the netted sum of electricity exports and imports for each Market Time Period for a given geographical area. In the context of this network code, geographical areas are the same as a Bidding Zone;

**Non Costly Remedial Action -** a Remedial Action is non costly if no direct payments are made;

**Operational Security Constraints –** reflect the limits that guarantee the secure and reliable operation of the interconnected power system;

**Order** - an intention to purchase or sell energy expressed by a Market Participant through a market platform subject to a certain number of execution conditions as determined by the rules governing that market platform. The Order may refer to several Market Time Periods but shall refer only to a single Bidding Zone;

**Physical Congestion -** a network situation, either described in a Common Grid Model, or occurring in real time, where Operational Security Constraints are not respected;

**Physical Risk -** is the combined effect of probability and consequences of all events on the electrical system;

**Post-Fault Remedial Action -** a Remedial Action that is applied after a fault;

**Pre-Fault Remedial Action -** a Remedial Action that is applied before a fault;

**Redispatching -** a measure activated by System Operators after the day ahead Allocation, by altering the generation and/or load pattern, in order to change physical flows in the grid and relieve a Physical Congestion;

**Reliability Margin -** the margin reserved on the permissible loading of a Critical Network Element or a Bidding Zone Border to cover against uncertainties between a capacity calculation timeframe and real time, taking into account the availability of Remedial Actions;

**Remedial Action -** means a measure activated by SOs, manually or automatically, that relieves or can relieve Physical Congestions. They can be applied pre-fault or post-fault and may involve costs.;

**Scheduled Exchange** – the transfer scheduled between geographic areas, for each Market Time Period and for a given direction. In Capacity Allocation and Congestion Management Network Code such geographical areas are Bidding Zones.

**Scheduled Exchange Calculator -** the function of calculating Scheduled Exchanges.

**Shared Order Book** –– a module within the pan-European Intraday solution collecting all matchable Orders from the participating Nominated Electricity Market Operators and performing continuous intraday matching of those Orders;

**Shipping Agent -** the function of transferring Net Position(s) between different Central Counter Parties.

**Social Welfare -** a quantification of Social Welfare shall at least contain the following dimension in order to assess the potential implications of alternative policy options:

* The additional economic benefit, defined as the sums of the additional individual benefits and costs which are expected to be accrued due to the implementation of the respective policy options compared to the status quo. These surpluses shall be analysed independently for the respective groups of stakeholders:
* Tariff customers;
* In its entirety; and
* As different groups previously defined as classes with differing affordability of electricity;
* Electricity consumers and generators;
* Market Participants; and
* System Operators.
* Assumptions about the redistributive effects of an increase of one of the above components for the surpluses of the other groups stated above.

**Sophisticated Product** – A product with specialist characteristics designed to reflect system operation practices or market needs, examples may include but shall not be limited to, Orders covering multiple Market Time periods and products reflecting start up costs;

**Stakeholder Committee –** A group of appointed representatives forming an advisory group created by the guideline on Governance;

**Structural Congestion -** congestion in the grid that:

* can be unambiguously defined;
* is predictable;
* is stable over time, i.e. does not change its geographic position in the network under short-term influences; and
* is frequently reoccurring under common circumstances.

**System Security –** the ability of the power system to withstand unexpected disturbances or contingencies;

**System Operator** – a function referring to various tasks and operational responsibilities assumed by TSOs pursuant to this Network Code, including the physical delivery of energy resulting from the Day Ahead and Intraday market transactions and from all interconnectors which have an impact on the Cross Zonal trading of electricity, without prejudice to the exemptions granted under Regulation (EC) No 1228/2003  and Regulation (EC) 714/2009 which shall continue to apply until the scheduled expiry date as decided in the granted exemption decision;

**Trade** – one or more Matched Orders;

**Transmission System Operator** - as defined in Article 2 of Directive 2009/72/EC.

**Article 3**

**CONFIDENTIALITY OBLIGATIONS**

All parties referred to in Article 1(2) shall preserve the confidentiality of the information and data submitted to them in the fulfilment of the obligations arising from this Network Code.

**Article 4**

**OBJECTIVES OF CAPACITY ALLOCATION & CONGESTION MANAGEMENT**

1. All parties shall cooperate in delivering the provisions specified in this Network Code, in order to promote the completion and efficient functioning of the internal market in electricity and to ensure the optimal management, coordinated operation and sound technical evolution of the European electricity transmission network.
2. This Network Code shall facilitate the achievement of the following objectives:
3. Promoting effective competition in the generation, trading and supply of electricity;
4. Ensuring system security in accordance with the operational security requirements referred to in Annex 1 of Regulation 714/2009;
5. Optimising the calculation and Allocation of Cross Zonal Capacity;
6. Ensuring non-discrimination (including between cross-border and internal exchanges of electricity);
7. Ensuring and enhancing the transparency and reliability of information; and
8. Contributing to the efficient long-term development of the European electricity sector.

in order to enhance pan-European Social Welfare.

1. In fulfilling the requirements of this Network Code, all parties shall use best endeavours to exploit synergies, draw on experience gained through, and to use solutions developed as part of, regional market coupling projects.

**Article 5**

**CONSULTATION**

1. Unless stated otherwise, any methodology or set of requirements that is specifically created or amended through a direction within this Network Code shall be consulted on with, at minimum, the Stakeholder Committee for a period of not less than 2 weeks by the party responsible for developing that methodology or set of requirements.
2. For the avoidance of doubt at least the following methodologies and sets of requirements shall be subject to consultation:
3. the capacity calculation regions and the amendments pursuant to Article 16 and Article 17;
4. the generation and load data provision methodology and amendments pursuant to Article 18 and Article 19;
5. the common grid model methodology and amendments pursuant to Article 20 and Article 21;
6. the capacity calculation methodology and amendments pursuant to Article 24 and Article 25;
7. a description of the System Operator set of requirements related to efficient Capacity Allocation pursuant to Article 46 (1) a);
8. a description of the Nominated Electricity Market Operator set of requirements pursuant to Article 46 (1) b);
9. a description of the proposal of the Market Coupling Operator pursuant to Article 46 (3);
10. a description of Algorithm Amendment requirements with direct and significant impact on efficient Capacity Allocation pursuant to Article 47 (1) and 47 (2);
11. a description of the methodology for the calculation of scheduled exchanges pursuant to Article 53 and Article 69; and
12. the Day Ahead Firmness deadline pursuant to Article 76.
13. The views of stakeholders emerging from the consultation shall be duly considered prior to the submission of the document for regulatory approval if detailed in Article 8 or for publication in all other cases.

 **Article 6**

**PUBLICATION OF INFORMATION REGARDING CAPACITY ALLOCATION & CONGESTION MANAGEMENT METHODS**

1. Unless specifically stated otherwise, any methodology or set of requirements that is specifically created through a direction within this Network Code shall be made publically available by System Operators, Nominated Electricity Market Operators or Market Coupling Operators when submitted for approval in accordance with Article 8 or after finalisation in all other cases.
2. The description of the functional requirements of any algorithm developed pursuant to this Network Code shall be made publically available.
3. System Operators, Market Coupling Operators and Nominated Electricity Market Operators shall use reasonable endeavours to ensure that published documents are clear and easily accessible.
4. For the avoidance of doubt at least the methodologies and sets of requirements which are consulted upon according to Article 5 (2) shall be made publically available after their approval.

**Article 7**

**TRANSPARENCY OF INFORMATION**

All parties shall ensure that information is published at a time and in a format which does not create an actual or potential competitive advantage or disadvantage to any individual party or category of party.

**Article 8**

**REGULATORY APPROVALS**

1. Consistent with Article 37(6)(c) of Directive 2009/72/EC, National Regulatory Authorities shall be responsible for approving the methodologies used to calculate or establish the terms and conditions for access to cross-border infrastructures, including the procedures for the allocation of capacity and congestion management.
2. System Operators, Nominated Electricity Market Operators and Market Coupling Operators shall, prior to the expiry of the deadline for developing procedures for the allocation of capacity and management of congestion specified in this Network Code submit those procedures, including a proposed timescale for implementation, to its National Regulatory Authority for approval.
3. National Regulatory Authorities shall, within three months of having received the procedures for the allocation of capacity and congestion management pursuant to Paragraph 1, provide System Operators, Nominated Electricity Market Operators or Market Coupling Operators as the case may be, with an approval or request to amend the proposed procedure for the allocation of capacity and congestion management.
4. In the event National Regulatory Authorities request an amendment to the proposed procedure for the allocation of capacity and congestion management, System Operators, Nominated Electricity Market Operators or Market Coupling Operators as the case may be, shall resubmit an amended procedure for approval within three months.
5. Where the competent National Regulatory Authorities have not been able to reach an agreement within a period of six months from when the case was referred to the last of those National Regulatory Authorities, or upon a joint request from the competent National Regulatory Authorities, the Agency shall decide upon those regulatory issues that fall within the competence of National Regulatory Authorities as specified under Article 8 of Regulation 713/2009.

**Title 2**

**GOVERNANCE**

**Article 9**

**FUNCTIONS IN CAPACITY ALLOCATION & CONGESTION MANAGEMENT**

1. The process of Capacity Allocation and Congestion Management under this Network Code shall involve the following functions:
2. System Operator;
3. Nominated Electricity Market Operator;
4. Market Coupling Operator;
5. Scheduled Exchange Calculator;
6. Market Information Aggregator;
7. Coordinated Capacity Calculator;
8. European Merging Function
9. Shipping Agent;
10. Central Counter Party; and
11. Congestion Income Distributor.

**Article 10**

**DESIGNATION OF NOMINATED ELECTRICITY MARKET OPERATORS**

1. For the purpose of efficient implicit Cross Zonal Capacity Allocation, all Member States electrically connected to another eligible Bidding Zone in another Member State shall ensure that one or more Nominated Electricity Market Operators, covering jointly in all required functions the whole territory of the Member State, participate in the Day Ahead Market and the Intraday Market. When designating the entities the fulfilment of the tasks defined in this network code in a coordinated manner shall be ensured.

1. Designation of Nominated Electricity Market Operators shall be for a period of time to be determined by the Member States having regard to considerations of:
2. Economic efficiency, competition and liquidity. After Nominated Electricity Market Operator designation, a reasonable preparatory period shall be allowed for Nominated Electricity Market Operator to become fully operational;
3. If there are no suitable organisations in a Member State to be nominated as a Nominated Electricity Market Operator, then the Member State shall foresee national measures for the establishment of such operators, or make arrangements which allow for Nominated Electricity Market Operators in other Member States to perform the necessary single price coupling and single intra-day market functions in their bidding zones;
4. In cases where more than one Nominated Electricity Market Operator is designated within in one Member State, the applicable designation criteria and operational arrangements shall ensure that competition between Nominated Electricity Market Operators is organized in a fair and non-discriminatory manner, in particular with respect to the no-preferential status to the national designation process and prevention of free-riding strategies between Nominated Electricity Market Operators exploiting the pooling of liquidity within the same single price coupling and single intra-day market mechanism. NRAs shall ensure monitoring of compliance of the Nominated Electricity Market Operators with the designation criteria;
5. A Member State shall revoke the designation where the Nominated Electricity Market Operator fails to maintain compliance with the criteria and is not able to restore compliance in a period of six months from the notification of the failure to the Nominated Electricity Market Operator by the NRA; and
6. The designation and de-designation of Nominated Electricity Market Operators shall be notified to the European Commission and published in the Official Journal of the European Union.
7. Nominated Electricity Market Operators shall fulfil the following designation criteria:
8. The Nominated Electricity Market Operators shall have or contract adequate resources for a common, coordinated and compliant operation of a single spot market and a single intra-day market, including fulfilment of the Market Coupling Operator functions, financial resources, necessary information technology, technical infrastructure and operational procedures or provide necessary proof that they are able to create these prerequisites within a reasonable preparatory period;
9. The Nominated Electricity Market Operators shall promote and maintain high standards of integrity and fair dealing in the conduct of business by ensuring that the participants have equally open access to relevant information, that the business is conducted in an orderly manner and appropriate measures are adopted to prevent abuse of the market including abuse of market power, facilitate its detection and monitor its incidence;
10. The Nominated Electricity Market Operators shall be cost-efficient;
11. The Nominated Electricity Market Operators shall have appropriate independence from market participants, they shall treat all market participants in a non-discriminatory way and the market surveillance at the Nominated Electricity Market Operator shall be appropriate;
12. The Nominated Electricity Market Operators shall have non-discriminatory Order collection and appropriate transparency and confidentiality agreements with market participants and the TSOs; and
13. The Nominated Electricity Market Operators shall have provision of the necessary clearing services.

**Article 11**

**DESIGNATION OF MARKET COUPLING OPERATORS**

1. Nominated Electricity Market Operators shall establish together with other Nominated Electricity Market Operators one or several Market Coupling Operators to perform the Market Coupling Operator functions defined in this network code, having regard to considerations of economic efficiency and liquidity.
2. If Nominated Electricity Market Operators fail to establish the Market Coupling Operators for either the intraday or the day-ahead timeframe, the European Commission may request ENTSO-E, to create or appoint a single regulated entity to which the functions of the Market Coupling Operators will be assigned.
3. The Agency shall evaluate the progress by Nominated Electricity Market Operators in establishing the Market Coupling Operators, in particular regarding the contractual and regulatory framework and regarding the technical preparedness to fulfil the Market Coupling Operator functions. The Agency shall make a recommendation at the latest by 30 June 2014, as to whether the European Commission shall request ENTSO-E to proceed in procuring the Market Coupling Operator function. In such a case, detailed appointment and selection criteria shall be provided by ENTSO-E and subject to an Agency opinion.

**Article 12**

**ASSIGNMENT OF FUNCTIONS TO TRANSMISSION SYSTEM OPERATORS**

1. While respecting the principles of transparency, proportionality and non-discrimination, each Member State shall, where required, assign the following functions to Transmission System Operators:
2. System Operator;
3. Scheduled Exchange Calculator;
4. Market Information Aggregator;
5. Coordinated Capacity Calculator;
6. European Merging Function
7. Shipping Agent; and
8. Congestion Income Distributor.

**Article 13**

**ASSIGNMENT OF FUNCTIONS TO NOMINATED ELECTRICITY MARKET OPERATORS**

1. While respecting the principles of transparency, proportionality and non-discrimination, each Member State shall, where required, assign the following functions to Nominated Electricity Market Operators:
2. Nominated Electricity Market Operator;
3. Market Coupling Operator; and
4. Central Counter Party.

**Article 14**

**DELEGATION OF FUNCTIONS**

1. System Operators and Nominated Electricity Market Operators shall be entitled to delegate any function assigned to them under this Network Code to a competent third party. Responsibility for compliance with the obligations under this Network Code shall remain the delegating System Operator and/or Nominated Electricity Market Operator.
2. In all cases, a third party shall have clearly demonstrated its ability to satisfactorily fulfil the obligations of the Network Code prior to delegation.
3. In the event that any function specified in this Network Code is delegated to a third party, the delegating party shall ensure that suitable confidentiality agreements have been put in place prior to delegation.

**Title 3**

**REQUIREMENTS**

**Chapter 1**

**CAPACITY CALCULATION**

**Section 1**

**GENERAL REQUIREMENTS**

**Article 15**

**CAPACITY CALCULATION TIMEFRAMES**

1. Capacity Calculation shall produce results for at least the following Capacity Calculation Timeframes:
2. Day Ahead; and
3. Intraday.
4. Unless stated otherwise, the requirements of this Network Code shall apply to all the Capacity Calculation Timeframes defined in paragraph 1.
5. All System Operators of each Capacity Calculation Region shall ensure that Cross Zonal Capacities are reassessed sufficiently often within the Intraday Timeframe based on the latest available information. The frequency of this Intraday reassessment shall be guided by the principles of cost-benefit analysis and System Security.

**Article 16**

**CAPACITY CALCULATION REGIONS**

1. No later than 1 month after the entry into force of this Network Code, all System Operators shall make a common proposal regarding the Capacity Calculation Regions within which Coordinated Capacity Calculation shall be performed.
2. In determining the Capacity Calculation Regions the following rules shall be complied with:

(a) Each Bidding Zone Border shall be attributed to one Capacity Calculation Region;
(b) The first definition of Capacity Calculation Regions according to this Network Code shall be based on the regions, as specified in Article 3 (2) of Annex 1 of Regulation (EC) No 714/2009; and
(c) The assessment shall be made against the objectives specified in Article 4.

1. The Capacity Calculation Regions applying a Flow Based Approach shall be merged to one Capacity Calculation Region provided that:
2. The Capacity Calculation Regions are linked power systems;
3. The Capacity Calculation Regions are within the same Capacity Allocation; and
4. Social Welfare is higher as a consequence of merging the Capacity Calculation Region than were the Capacity Calculation Regions kept separate.
5. In the event that no proposal has been made in the timescale defined in paragraph 1, all National Regulatory Authorities shall be entitled to define Capacity Calculation Regions.

**Article 17**

 **AMENDMENTS OF CAPACITY CALCULATION REGIONS**

In the event that all System Operators or all National Regulatory Authorities identify a need to reassess the Capacity Calculation Regions, all System Operators may propose a new common definition of Capacity Calculation Regions. The proposal shall be based on Article 16(2) and 16(3).

**SECTION 2**

**THE COMMON GRID MODEL**

**Article 18**

**GENERATION AND LOAD DATA PROVISION METHODOLOGY**

1. No later than 4 months after the entry into force of this Network Code, all System Operators shall develop a proposed methodology for the delivery of generation and load data required to establish the Common Grid Model. This document shall be termed the generation and load data provision methodology.
2. The generation and load data provision methodology shall detail which generation and load units shall be required to provide information to their respective System Operators for the purposes of Capacity Calculation. The proposal shall include a justification, based on the objectives of Article 4, demonstrating why System Operators require the information.
3. The generation and load data provision methodology shall detail the information to be provided by generation and load units to System Operators. The information shall include, but not be limited to the following:
4. Information related to technical data;
5. Information related to availability;
6. Information related to scheduling of generation units; and
7. Information related to price estimation for generation.
8. The proposal shall include time schedules for providing information.
9. All System Operators shall use and share with other System Operators the information related to paragraph 3.  Information in 3(iv) shall be used for Capacity Calculation purposes only.
10. All System Operators shall publish no later than 2 months after the approval by all National Regulatory Authorities:
11. A list of parties required to provide information;
12. A list of information to be provided; and
13. A time schedule for providing information.

**Article 19**

**AMENDMENT OF THE GENERATION AND LOAD DATA PROVISION METHODOLOGY**

1. All System Operators shall be entitled to develop proposals to amend the generation and load data provisions methodology.

1. Any proposal for amendment(s) shall be supported by a justification based on the objectives specified in Article 4.
2. All System Operators shall update the information published in accordance with Article 18(6) to reflect the approval of National Regulatory Authorities no later than 2 months after the approval of the amendment(s).

**Article 20**

**COMMON GRID MODEL METHODOLOGY**

1. No later than 6 months after the entry into force of this Network Code, all System Operators shall produce a Common Grid Model methodology.
2. The Common Grid Model Methodology shall enable the establishment of the Common Grid Model and shall meet the objectives specified in Article 4. At a minimum, it shall contain:
3. building scenarios in accordance with Article 22;
4. building individual grid models in accordance with Article 23 and
5. A description to merge individual grid models to form the Common Grid Model.

**Article 21**

**AMENDMENT OF THE COMMON GRID MODEL METHODOLOGY**

1. All System Operators or all National Regulatory Authorities shall be entitled to launch a reassessment of the Common Grid Model Methodology.
2. Where a reassessment of the Common Grid Model methodology is launched, all System Operators shall develop a proposal to amend or maintain the current Common Grid Model Methodology in accordance with Article 20.

**Article 22**

**SCENARIOS**

1. All System Operators shall define a common set of scenarios for each Capacity Calculation Timeframe for use in the Common Grid Model.

1. All System Operators shall define one scenario per Market Time Period for the Day Ahead and Intraday Capacity Calculation Timeframe.
2. All System Operators shall define, for each scenario, common rules fixing the Net Position for each Bidding Zone and the flow for each Direct Current line. These common rules shall be based on the best forecast of the Net Position and flows for each scenario and include also the overall balance constraint for the European interconnected power system.

 **Article 23**

 **INDIVIDUAL GRID MODEL**

1. The Individual Grid Model shall represent the best forecast of power system conditions for the specified Market Time Period as perceived at the moment at which the Individual Grid Model is created.

1. All System Operators of each Bidding Zone shall provide a single Individual Grid Model which respects the rules defined in Article 22(3).
2. Individual Grid Models shall cover the relevant part of the European power system needed for the capacity calculation.
3. All System Operators shall use best endeavours to progressively harmonize the way in which Individual Grid Models are built.
4. Each System Operator shall provide all necessary data in the Individual Grid Model to allow active and reactive power flow and voltage analyses in steady state.
5. Where appropriate, and upon agreement among System Operators within the Capacity Calculation Region, each System Operator of that Capacity Calculation Region shall exchange data to enable voltage and dynamic stability analyses.

**SECTION 3**

**CAPACITY CALCULATION METHODOLOGIES**

**Article 24**

**CAPACITY CALCULATION METHODOLOGIES**

1. No later than 12 months after the entry into force of this Network Code, all System Operators of each Capacity Calculation Region shall produce a common Capacity Calculation Methodology.
2. The Capacity Calculation methodology for a Capacity Calculation Region shall meet the objectives defined in Article 4 and shall contain at least the following for each Capacity Calculation Timeframe:
3. Capacity Calculation inputs:
4. A determination of the Reliability Margin in accordance with Article 27;
5. A determination of relevant Operational Security Constraints in accordance with Article 29;
6. A determination of allocation constraints to be taken into account directly in capacity allocation in accordance with Articles 30
7. A construction Generation Shift Keys in accordance with Article 31;
8. Remedial actions:
9. A determination of Remedial Actions to be considered in capacity calculation in accordance with Article 34;
10. An efficient selection and combination of remedial actions pursuant to Article 4 from the available remedial actions determined in (b)(i) for capacity calculation in accordance with Articles 34 and 83 where appropriate;
11. Capacity Calculation Approach:
12. A Capacity Calculation Approach to be applied pursuant to Article 26;
13. A mathematical description of the applied Capacity Calculation Approach with different capacity calculation inputs;
14. A rule to handle already allocated Cross Zonal Capacities, where appropriate;
15. A rule to share the Cross Zonal Capacities between the borders of the Capacity Calculation Regions prior to Capacity Allocation, where appropriate, and when using the Coordinated NTC Approach; and
16. A rule to share the Cross Zonal Capacities between the different Capacity Calculation Regions prior to Capacity Allocation, where appropriate; and
17. Validation of Cross Zonal Capacities:
18. A validation of the Cross Zonal Capacities in accordance with Article 33.
19. The Capacity Calculation methodology shall include the frequency of the Intraday assessment, including a justification as specified in Article 15(3).
20. The Capacity Calculation methodology shall include a fallback solution to ensure Capacity Calculation in the event that the Capacity Calculation Process is unable to produce results.
21. All System Operators of each Capacity Calculation Region shall use best endeavours to progressively harmonize Capacity Calculation inputs and the Remedial Actions used for the Capacity Calculation.
22. All System Operators shall use best endeavours to progressively harmonize the Capacity Calculation Methodologies across the Capacity Calculation Regions.

**Article 25**

**AMENDMENTS TO CAPACITY CALCULATION METHODOLOGIES**

1. All System Operators of a Capacity Calculation Region or all National Regulatory Authorities of a Capacity Calculation Region shall be entitled to reassess the Capacity Calculation Methodology for a Capacity Calculation Region.
2. Where a reassessment of the Capacity Calculation Methodology of a Capacity Calculation Region is launched, all System Operators of that Capacity Calculation Region shall develop a proposal to amend or maintain the current Capacity Calculation Methodology of the Capacity Calculation Region in accordance with Article 24.

**Article 26**

**CAPACITY CALCULATION APPROACHES**

1. For the Day Ahead and Intraday Capacity Calculation Timeframes the Capacity Calculation Approach shall be a Flow Based Approach in all cases, except where the requirements of paragraph 2 are met.
2. System Operators shall be entitled to apply a Coordinated NTC Approach:
3. For Capacity Calculation Regions in which the distribution of power flows is not highly influenced by exchanges between Bidding Zones in other Capacity Calculation Regions; or
4. If the application of the Flow Based Approach would not fulfil the following prerequisites:
5. Ensure System Security;
6. Lead to an increase in Social Welfare in the Capacity Calculation Region; and
7. Provide Market Participants with sufficient time to adopt their processes.

**Article 27**

**RELIABILITY MARGIN**

1. The Reliability Margin shall take into account uncertainties between a capacity calculation timeframe and real time by performing a risk assessment taking into account operational security, remedial actions available after Capacity Calculation, and financial risk arising as a consequence of the applicable firmness regime.
2. The Reliability Margin shall integrate a statistical analysis of historic data showing the deviation of power flows and shall take into account expectation of future deviations. Among other things, it shall consider deviations caused by:
3. The activation of load frequency control reserves within a Market Time Period; and
4. Uncertainties and hypotheses affecting capacity calculations between the Capacity Calculation Timeframe and real time, for the Market Time Period being considered.

**Article 28**

**SIZE OF RELIABILITY MARGIN**

1. For each Capacity Calculation Timeframe, each System Operator shall define the size of the Reliability Margin on its Critical Network Elements or its Bidding Zone Borders based on the specification in Article 27.
2. In the event that the size of the Reliability Margin on Critical Network Elements or on Bidding Zone Borders defined by neighbouring TSOs differs, the highest value shall be applied in the capacity calculation.

**Article 29**

**OPERATIONAL SECURITY CONSTRAINTS**

1. Each System Operator shall define relevant constraints, at least of the following type, under the relevant contingencies, in accordance with operational security requirements and Article 30:
2. Thermal limits of the Critical Network Elements;
3. Voltage limits, imposing admissible substation voltage ranges;
4. Dynamic or voltage stability limits ensuring the stability of the power system, where appropriate;
5. Short circuit current limits, where appropriate;
6. Generation limits ensuring adequate availability of generation reserves to meet the requirements for operational security, where appropriate; or
7. Minimum generation limits to ensure adequate frequency and voltage control capabilities, where appropriate.
8. Each System Operator shall, if requested to do so by its National Regulatory Authority, providing information regarding the relevance of the Critical Network Elements.

**Article 30**

**ALLOCATION CONSTRAINTS**

1. The determination of allocation constraints required by the Capacity Calculation Methodology developed pursuant to Article 24 may contain the use of:
2. Operational Security Constraints in accordance with Article 29; or
3. Other type of constraints, which may include but are not limited to transmission losses and ramping constraints.

**Article 31**

**GENERATION SHIFT KEYS**

1. All System Operators of each Bidding Zone shall build Generation Shift Keys for each scenario developed in Article 22.
2. A Generation Shift Key shall represent the best forecast of the translation of a change in the Net Position of a Bidding Zone into a specific change of generation and/or load in the Common Grid Model. This forecast shall make use of information in the generation and load data provision methodology.

**Article 32**

**REMEDIAL ACTIONS**

1. Capacity Calculation methodology shall define which Remedial Actions may be used in Capacity Calculation pursuant to the objectives specified in Article 4.

1. Each System Operator shall ensure that Remedial Actions shall be considered in the Capacity Calculation under the condition that the remaining available Remedial Actions together with the Reliability Margin defined in Article 28 are sufficient to ensure operational security.
2. Each System Operator shall ensure that the considered Remedial Actions will be the same for all Capacity Calculation Timeframes taking into account their technical availabilities for each Capacity Calculation Timeframe.
3. Each System Operator shall use available Non Costly Remedial Actions during Capacity Calculation.
4. All System Operators of each Capacity Calculation Region shall coordinate regarding the use of Remedial Actions for Capacity Calculation.
5. All System Operators of each Capacity Calculation Region shall agree on the use of Cross Control Area Remedial Actions in Capacity Calculation.

**Article 33**

**CROSS ZONAL CAPACITY VALIDATION**

1. When validating Cross Zonal Capacities, each System Operator shall correct or accept Cross Zonal Capacities relevant to the System Operator’s Bidding Zone Borders provided by the Coordinated Capacity Calculator.
2. Where a Coordinated NTC Approach is applied, all System Operators of the Capacity Calculation Region shall include in the Capacity Calculation Methodology a rule for splitting the correction between the different Bidding Zone Borders.
3. During the validation process, and only for reasons of system security, each System Operator shall be entitled to reduce the Cross Zonal Capacity on its Bidding Zone Borders or its Critical Network Elements.
4. All reductions shall be reported in the biennial report on Capacity Calculation produced in accordance with Article 38 and justifications and explanations for the reductions in the Cross Zonal Capacities shall be provided.
5. Each Coordinated Capacity Calculator shall operate in coordination with the neighbouring Coordinated Capacity Calculators. This coordination shall be ensured by neighbouring System Operators and be achieved by exchanging and confirming information regarding the interdependency between the regional Coordinated Capacity Calculators relevant for the capacity calculation and validation. Neighbouring System Operators shall provide information on the interdependency to the Coordinated Capacity Calculators before the capacity calculation. The biennial report prepared in accordance with Article 38 shall contain an assessment of the accuracy of this information and relevant corrective measures, where appropriate.

**SECTION 4:**

**THE CAPACITY CALCULATION PROCESS**

**Article 34**

**GENERAL PROVISIONS**

1. No later than 12 months after the entry into force of this Network Code, all System Operators shall establish a European Merging Function and define rules for the operation of the European Merging Function.
2. No later than 12 months after the entry into force of this Network Code, all System Operators of each Capacity Calculation Region shall establish a Coordinated Capacity Calculator and define rules for the operation of the Coordinated Capacity Calculator.
3. The Coordinated Capacity Calculators shall cover the Capacity Calculation Process at least on a regional basis, as defined in Article 36, and the management of the validation of Cross Zonal Capacity values and the provision of information for the purposes of Capacity Allocation as defined in Article 37.
4. Each System Operator shall periodically review the quality of data submitted within the Capacity Calculation Process to ensure it facilitates the achievement of the objectives specified in Article 4.

**Article 35**

**CREATION OF THE COMMON GRID MODEL**

1. For each Capacity Calculation Timeframe, each generator or load unit included in the generation and load data provision methodology established pursuant to Article 18 shall provide the data specified in the methodology in the timescales specified in the methodology to the System Operator responsible for the respective Control Area.
2. Each generator or load unit providing information pursuant to Article 18(3) shall use best endeavours to deliver as reliable a set of estimations as practicable.
3. For each Capacity Calculation Timeframe, all System Operators of each Bidding Zone shall provide one Individual Grid Model for each scenario to the European Merging Function and all other System Operators, in accordance with Article 23.
4. Each System Operator shall use best endeavours to deliver as reliable set of estimations for each Individual Grid Model as practicable.
5. For each Capacity Calculation Timeframe, the European Merging Function shall create a single, Europe wide, Common Grid Model for each scenario by merging inputs from all System Operators.
6. The European Merging Function shall provide the Common Grid Model for each scenario to each Coordinated Capacity Calculator and to each System Operator.

**Article 36**

**REGIONAL CALCULATIONS OF CROSS ZONAL CAPACITIES**

1. For each Capacity Calculation Timeframe, each System Operator of each Capacity Calculation Region shall provide the Coordinated Capacity Calculator and all System Operators of that Capacity Calculation Region with Operational Security Constraints, Generation Shift Keys, Remedial Actions and Reliability Margins, as defined according to Article 24(2)and Allocation Constraints as defined according to Article 30.
2. Each System Operator shall use best endeavours to deliver a reliable estimation for each Generation Shift Key.
3. Each Coordinated Capacity Calculator shall perform system security analysis using the Common Grid Model created pursuant to Article 35 for each scenario.
4. When calculating Cross Zonal Capacities, each Coordinated Capacity Calculator shall calculate the impact of the change of Bidding Zone Net Positions and flows on Direct Current lines using Generation Shift Keys.
5. When calculating Cross Zonal Capacities, each Coordinated Capacity Calculator shall ensure that, all the sets of Bidding Zone Net Positions and flows on Direct Current lines not exceeding the Cross Zonal Capacities, shall respect the Operational Security constraints and Reliability Margin pursuant to Article 24(2)(a) and take into account already Allocated Cross Zonal Capacities pursuant to Article 24(2)(c).
6. Each Coordinated Capacity Calculator shall optimize Cross Zonal Capacities using available Remedial actions for Capacity Calculation in accordance with Article 24(2)(b).
7. Each Coordinated Capacity Calculator shall apply the sharing rules established pursuant to Article 24(2)(c).
8. Each Coordinated Capacity Calculator shall respect the mathematical description of the applied Capacity Calculation Approach pursuant to Article 24(2)(c).
9. Each Coordinated Capacity Calculator applying:
10. The Coordinated NTC Approach shall produce the Cross Zonal Capacity values for each Bidding Zone within the Capacity Calculation Region; or
11. The Flow Based Approach shall produce the Flow Based Parameters for each Bidding Zone within the Capacity Calculation Region.
12. Each Coordinated Capacity Calculator shall submit the Cross Zonal Capacities for validation, pursuant to Article 24(2)(d), to each System Operator within that Capacity Calculation Region.

**Article 37**

**VALIDATION AND DELIVERY OF CROSS ZONAL CAPACITIES**

1. Each System Operator shall validate the results of the Regional Capacity Calculation on its Bidding Zone Borders or Critical Network Elements, in accordance with Article 33.
2. Each System Operator shall send its capacity validation to the relevant Coordinated Capacity Calculator(s) and to the other System Operators of the relevant Capacity Calculation Region(s).
3. Results of the validation together with the Allocation Constraints shall be provided by each Coordinated Capacity Calculator for the execution of capacity allocation.

 **Section 5**

**BIENNIAL REPORT ON CAPACITY CALCULATION**

**Article 38**

**BIENNIAL REPORT ON CAPACITY CALCULATION**

1. No later than 2 years after the entry into force of this Network Code all System Operators shall prepare and send to all National Regulatory Authorities a report on the Capacity Calculation Process.
2. In every second subsequent year, all System Operators shall prepare and send to all National Regulatory Authorities a report on the Capacity Calculation Process if requested to do so by all National Regulatory Authorities.
3. The report on Capacity Calculation shall contain for each Bidding Zone, Bidding Zone Border or Capacity Calculation Region at least:
4. The Capacity Calculation Approach used;
5. Statistical indicators on Reliability Margins;
6. Statistical indicators of the Cross Zonal Capacity for each Capacity Calculation Timeframe;
7. Quality indicators for the information used within the Capacity Calculation; and
8. Where appropriate, proposed improvement measures, including an evaluation of the continued application of the coordinated NTC Approach.
9. Statistical and quality indicators for the report shall be commonly agreed between all System Operators.
10. Each System Operator shall provide relevant data to allow the preparation of the report in a timely manner.

**CHAPTER 2:**

**BIDDING ZONES**

**SECTION 1**

**GENERAL PROVISIONS**

**Article 39**

**DETERMINATION OF BIDDING ZONES**

1. Bidding Zones shall be defined in a manner which enhances Social Welfare, taking into account:
2. Efficient congestion management and the secure network operation within and between Bidding Zones; and
3. Overall market efficiency and competition in electricity markets.
4. When assessing the configuration of Bidding Zones, at least the criteria listed in Article 40 shall be considered.
5. Bidding Zones shall be consistent for all Capacity Calculation Timeframes.

**Article 40**

**CRITERIA TO DEFINE AND ASSESS THE EFFICIENCY OF ALTERNATIVE BIDDING ZONE CONFIGURATIONS**

1. When the Bidding Zone configuration is reviewed, at least the following criteria shall be considered:
2. In respect of network security:
3. The ability of the Bidding Zone configuration to ensure the operational security and the security of supply; and
4. The size of uncertainties in the Cross Zonal Capacity Calculation.
5. In respect of overall market efficiency:
6. The change in economic surplus arising from the change;
7. Market efficiency, including, at least, firmness costs in accordance with Article 90, market liquidity, market concentration and market power, the facilitation of effective competition, the accuracy and robustness of price signals and transition costs, including costs of amending existing contractual obligations, incurred by Market Participants, Market Operators and System Operators;
8. The need to ensure the feasible market outcome without an extensive application of economically inefficient corrective measures;
9. Any adverse effects of internal transactions on other Bidding Zones; and
10. The impact on the operation and efficiency of the balancing mechanisms and imbalance settlement processes.
11. In respect of the stability and robustness of Bidding Zones:
12. The need for Bidding Zones to be sufficiently stable and robust over time; and
13. The location and frequency of congestion, provided that: structural congestions influence the delimitation of bidding zones; and taking into account ongoing investments which may relieve existing congestions.

**SECTION 2**

**BIENNIAL REPORT**

**Article 41**

**BIENNIAL REPORT ON CURRENT BIDDING ZONE CONFIGURATION**

1. The objective of the biennial report on the current European Bidding Zone configuration is to identify the need to launch the process for reviewing the Bidding Zone configuration in accordance with Article 43. This shall be achieved by monitoring the efficiency of the existing Bidding Zone configuration.

1. The efficiency of current Bidding Zones shall be assessed every two years. The assessment shall consist of:
2. A biennial technical report, as defined in Article 42, prepared by all System Operators containing a recommendation as to whether a process for reviewing the Bidding Zone configuration in accordance with Article 43 should be launched and specifying the relevant geographic area for such an assessment;
3. An evaluation of market structure and possible market power issues prepared by all National Regulatory Authorities and the Agency taking into account the biennial technical report; and
4. A decision by all National Regulatory Authorities either to approve the current Bidding Zone configuration or to request to launch a process for reviewing the Bidding Zone configuration in accordance with Article 43.

1. The first biennial technical report shall be delivered no later than 6 months after the entry into force of this Network Code, and thereafter on a biennial basis, by the end of March of each year. The biennial technical report shall provide information for the calendar year finishing on the 31 December of the previous year.

**Article 42**

**BIENNIAL TECHNICAL REPORT**

1. The biennial technical report shall include, at least:
2. a list of Structural Congestions and other major Physical Congestions, including their location and frequency;
3. an analysis of the expected evolution of these Physical Congestions due to investments in networks or due to significant changes in generation or consumption patterns;
4. an analysis of the share of power flows that do not result from the Capacity Allocation mechanism, for each Capacity Calculation Region where appropriate; and
5. Congestion Incomes and firmness costs incurred in accordance with Article 90.

2. Each System Operator shall provide data and analysis to allow the preparation of the biennial technical report in a timely manner.

**SECTION 3**

**REVIEW OF BIDDING ZONE CONFIGURATION**

**Article 43**

**REVIEW OF BIDDING ZONE CONFIGURATION**

1. The review of the Bidding Zone configuration shall determine whether the current Bidding Zone configuration should be maintained or whether an alternative Bidding Zone configuration should be implemented. This shall be achieved by ensuring:
2. That all necessary analyses required to take a decision on the Bidding Zone configuration is performed;
3. The sufficient involvement of stakeholders; and
4. That responsibilities are clearly allocated between the parties responsible for preparing the analyses and the parties responsible for taking decisions on the Bidding Zone configuration.
5. A review of the Bidding Zone configuration may be launched by:
6. All National Regulatory Authorities as described in Article 41;
7. All National Regulatory Authorities upon recommendation of the Agency or a System Operator; or
8. A System Operator, with the approval of its National Regulatory Authority, inside the System Operator’s Control Area, where the distribution of power flows is not highly influenced by exchanges between other Bidding Zones outside the System Operator's Control Area, if:
9. The Bidding Zone configuration is necessary in a hydro dominated systems due to rapid and unforeseen changes in network topology, patterns of generation and/or load or local energy situations (deficit or surplus), and when the zone delimitation is deemed to be the adequate measure to preserve the system security or to prevent the significant social welfare loss; or
10. The Bidding Zone configuration has negligible impact on the neighbouring System Operators' Control Area and is needed to efficiently maintain the system security or to prevent a social welfare loss inside the System Operator’s Control Area.
11. In the event that all National Regulatory Authorities decide to launch a review of the Bidding Zone configuration pursuant to paragraphs 2 (a) or 2 (b), they shall specify:
12. The geographic area(s) in which the Bidding Zone configuration shall be studied and the neighbouring geographic area(s) for which the impacts shall be taken into account;
13. The participating System Operator(s); and
14. The participating National Regulatory Authority(ies).
15. When a System Operator, having gained the approval of its National Regulatory Authority, decides to launch a review of Bidding Zone configuration pursuant to paragraph 2 (c):
16. The geographic area where Bidding Zone configuration is studied shall be limited to the Control Area of that System Operator;
17. That System Operator shall be the only participating System Operator;
18. That National Regulatory Authority shall be the only participating National Regulatory Authority;
19. The launch of the review of Bidding Zone configuration shall be notified and justified by the System Operator to the neighbouring System Operators, in timescales agreed bilaterally between those System Operators, and by the National Regulatory Authority to the neighbouring National Regulatory Authorities, before the application; and
20. Such a review process shall be transparent, while taking into consideration the time constraints for such review.
21. The participating System Operator(s) involved in the review of the Bidding Zone configuration shall:
22. Perform the assessment of the Bidding Zone configuration. This assessment shall be undertaken in a coordinated way, unless paragraph 43(2)(c) applies, and include Nominated Electricity Market Operators;
23. Propose an alternative Bidding Zone configuration(s);
24. Assess the current Bidding Zone configuration and each alternative Bidding Zone configuration(s) using the criteria specified in Article 40;
25. Perform a public consultation regarding the alternative Bidding Zone configuration proposal(s) relative to the existing Bidding Zone configuration, including proposing timescales for implementation, unless paragraph 36 (2)(c)(i) applies;
26. Make a proposal to maintain or amend bidding zone configuration.
27. Nominated Electricity Market Operators or other Market Participants shall, if requested by System Operators, provide participating System Operators with the relevant information or contribution to the process for assessing the Bidding Zone configuration. This information shall be shared between the participating System Operator(s) for the purpose of the process for assessing the Bidding Zone configuration only.

**CHAPTER 3**

**Section 1**

**Article 44**

**REDISPATCHING AND COUNTERTRADING**

1. Each System Operator shall agree, at least with all System Operators of its Capacity Calculation Region, on Redispatching and/or Countertrading arrangements.
2. Each System Operator shall be entitled to redispatch all available generation units in accordance with the appropriate mechanisms or/and bilateral agreements applicable to its Control Area.
3. All System Operators shall use Redispatching and/or Countertrading resources efficiently taking into account impact on system security and economic effectiveness.
4. The pricing of Redispatching shall be based on market prices. Until market prices are established for this purpose, generation and load units shall ex-ante provide information necessary for calculating the Redispatching cost to the relevant System Operators to allow the estimation of Redispatching costs. This information shall be shared between the relevant System Operators for Redispatching purposes only.

**CHAPTER 4**

**ALGORITHM DEVELOPMENT & AMENDMENT**

**Section 1**

**Article 45**

**GENERAL PROVISIONS**

1. Market Coupling Operators shall develop, maintain and operate:
2. A single Price Coupling Algorithm; and/or
3. A Continuous Trading Matching Algorithm.

 compliant with the requirements specified in this Network Code.

1. Market Coupling Operators shall use best endeavours to ensure that the Price Coupling Algorithm and the Continuous Trading Matching Algorithm produce the results identified in Articles 49 and Article 63 respectively.
2. Market Coupling Operators shall develop and implement such back-up systems as they deem to be required to fulfil the best endeavours obligation under paragraph 2.
3. Back-up arrangements shall not be subject to consultation requirements in accordance with Article 5 and publication requirements in accordance with to Article 6.

**Article 46**

**ALGORITHM DEVELOPMENT**

1. No later than 5 months after the entry into force of this Network Code:
2. All System Operators shall jointly provide Market Coupling Operators with a set of requirements related to efficient Capacity Allocation to enable the development of the Price Coupling Algorithm and the development of the Continuous Trading Matching Algorithm. These requirements shall specify the functionalities and performance, including deadlines for the delivery of market coupling results and details of the Cross Zonal Capacities and other Allocation Constraints which shall be respected; and
3. All Nominated Electricity Market Operators shall jointly provide Market Coupling Operators with a set of requirements related to efficient Matching to enable the development of the Price Coupling Algorithm and the Continuous Trading Matching Algorithm.
4. Any proposal provided pursuant to paragraph 1 shall facilitate the achievement of the objectives specified in Article 48 in the case of the Price Coupling Algorithm and Article 62 in the case of the Continuous Trading Matching Algorithm and the Objectives of Capacity Allocation and Congestion Management specified in Article 4.
5. As soon as reasonably practicable, and no later than 5 months after the receipt of the requirements required by paragraph 1, Market Coupling Operators shall develop a proposal for a single Price Coupling Algorithm and a proposal for a Continuous Trading Matching Algorithm which meets the requirements specified by System Operators and Nominated Electricity Market Operators in accordance with paragraph 1 and the objectives specified in Articles 4, 48 and 62. This proposal shall include the latest time by which Nominated Electricity Market Operators shall submit received Orders to Market Coupling Operators.
6. This proposal shall be submitted by Market Coupling Operators to System Operators and Nominated Electricity Market Operators. If appropriate, Market Coupling Operators shall work with Nominated Electricity Market Operators and System Operators for a period of not more than 2 months to refine the proposal such that it better meets the requirements specified in paragraph 1.
7. System Operators shall submit those elements of the proposals developed pursuant to paragraph 4 which have a direct and significant impact on efficient Capacity Allocation including a timeline for implementation to the respective National Regulatory Authorities for decision consistent with Article 8.
8. In the event that, in the opinion of Market Coupling Operators, the Nominated Electricity Market Operators or System Operators, it would not be feasible to meet a timescale specified in paragraphs 1-4, the Market Coupling Operator, the Nominated Electricity Market Operators or System Operators shall be entitled to submit a proposal to amend the timescale specified in paragraphs 1-4 to National Regulatory Authorities.   The proposal shall include information detailing the reasons for the extension and shall demonstrate that the timescale is proportionate.

**Article 47**

**ALGORITHM AMENDMENT**

1. In the event that System Operators identify an amendment to the Price Coupling Algorithm or Continuous Trading Matching Algorithm that has a direct and significant impact on efficient Capacity Allocation; System Operators shall jointly provide an updated set of requirements to the Market Coupling Operator.
2. In the event that Market Coupling Operators or Nominated Electricity Market Operators identify an amendment that has a direct and significant impact on the Price Coupling Algorithm or the Continuous Trading Matching Algorithm; Market Coupling Operators or Nominated Electricity Market Operators shall provide information to System Operators outlining the rationale for the proposed amendment.
3. If related to Capacity Allocation, System Operators shall review the proposed amendment and may provide an updated set of requirements in line with the proposed amendment to Market Coupling Operators.
4. If the proposed amendment is not related to Capacity Allocation, System Operators shall notify Market Coupling Operators and the Nominated Electricity Market Operators and National Regulatory Authorities of their decision.
5. National Regulatory Authorities may, within one month of receiving a notification of a decision pursuant to Paragraph 2, be entitled to recommend that the decision is altered.

**CHAPTER 4**

**THE DAY AHEAD ELECTRICITY MARKET**

**SECTION 1**

**THE PRICE COUPLING ALGORITHM**

 **Article 48**

**OBJECTIVES OF THE PRICE COUPLING ALGORITHM**

1. The Price Coupling Algorithm shall determine the results specified in Article 49 (2), in a manner which:
2. maximises economic surplus for the price coupled region for the subsequent trading day;
3. uses the marginal pricing principle to generate results per Bidding Zone per Market Time Period;
4. respects Cross Zonal Capacities and Allocation Constraints; and
5. is repeatable and scalable;
6. The Price Coupling Algorithm shall be capable of being efficiently extended to a larger or smaller number of Bidding Zones.

**Article 49**

**INPUTS & RESULTS**

1. In order to determine results, the Price Coupling Algorithm shall use:
2. Allocation Constraints;
3. the validated results defined in accordance with Article 37; and
4. Orders submitted in accordance with Article 50.
5. The Price Coupling Algorithm shall, at least, simultaneously determine the following information for each Market Time Period:
6. Allocation Constraints submitted in accordance with Article 37 (3);
7. the validated Cross Zonal Capacities submitted in accordance with Article 37 (3); and
8. Orders submitted in accordance with Article 50.

**Article 50**

**FORMAT OF ORDERS**

1. Orders submitted to the Price Coupling Algorithm shall be expressed in terms of Euros.
2. In the event that Market Coupling Operators, Nominated Electricity Market Operators, System Operators or National Regulatory Authorities identify that the maximum and minimum prices in place within a Day Ahead market could fail to facilitate the objectives specified in Article 4 or Article 48, they shall notify Market Coupling Operators who shall, as soon as reasonably practicable but no later than 3 months after the point at which the impact is identified, propose and consult on harmonised maximum and minimum bid price to be applied in all Bidding Zones covered by this Network Code.

**Article 51**

**PRODUCTS ACCOMMODATED**

1. Market Coupling Operators shall, at least, ensure that the Price Coupling Algorithm is capable of accommodating hourly products, multi-hour products and products covering parts of an hour. Products shall be compatible with Market Time Periods as defined in Article 2.
2. Nominated Electricity Market Operators shall periodically, but at least every two years, consult with:
3. Market Participants to ensure that available products reflect their needs;
4. System Operators to ensure products are reflective of power system security; and
5. National Regulatory Authorities to ensure that the available products promote the objectives specified in Article 4 and Article 48.

**Article 52**

**PRICING OF DAY AHEAD CAPACITY**

1. Day Ahead Cross Zonal Capacity shall be priced:
2. Reflecting Market Congestion; and
3. In a manner which defines the price of Day Ahead transmission capacity between zones as the difference between the corresponding Day Ahead Clearing Price of the relevant Bidding Zones.

**Article 53**

**METHODOLOGY FOR THE CALCULATION OF SCHEDULED EXCHANGES**

1. Where notifications of Scheduled Exchanges are required by System Operators, as soon as reasonably practicable after the entry into force of this Network Code and no later than 12 months from that date, System Operators shall define and implement a methodology to be used in calculating Scheduled Exchanges.
2. The calculation shall be based on Net Positions and shall respect the principles set out in Article 4 (2).

**Article 54**

**AMENDMENT OF THE METHODOLOGY FOR CALCULATING SCHEDULED EXCHANGES**

1. Where Scheduled Exchanges are required by System Operators, System Operators shall periodically review the methodology and where they identify an opportunity to amend the methodology such that it better fulfils the principles specified in Article 4, they shall update the methodology.

**Article 55**

**ESTABLISHMENT OF FALLBACK PROCEDURES**

1. System Operators shall ensure that robust and timely fallback solutions are in place to ensure efficient, transparent and non-discriminatory Capacity Allocation in the event that the Market Coupling Process is unable to produce results.
2. Prior to the commencement of the Market Coupling Process, as defined in Articles 56 to 61, System Operators shall facilitate the development of one or more fallback solution(s) capable of effectively dealing with a range of foreseeable events which may prevent the production of results and allocation of capacity according to this Network Code. Fallback solutions shall, as far as reasonably practicable, facilitate the achievement of the objectives specified in Article 4 and Article 48.
3. In developing fallback solutions System Operators shall work collaboratively with Nominated Electricity Market Operators and Market Coupling Operators.
4. Fallback arrangements shall not be subject to consultation pursuant to Article 5 and publication according to Article 6.

**SECTION 3**

**THE DAY AHEAD MARKET COUPLING PROCESS**

**Article 56**

**PROVISION OF INPUT DATA**

1. System Operators shall, for each Market Time Period, provide the input data specified in Article 49 (1) (a) to Market Coupling Operators.
2. The Coordinated Capacity Calculators shall, for each Market Time Period, provide the input data specified Article 49 (1) (b) to Market Coupling Operators.
3. Input data shall be provided as soon as reasonably practicable but in time to ensure the publication of the Cross Zonal Capacities to the market not later than 11.00 Market Time D-1.
4. If a Coordinated Capacity Calculator is unable to provide Cross Zonal Capacities one hour prior to the closure of the Day Ahead electricity market, that Coordinated Capacity Calculator shall notify the Market Information Aggregator(s), Market Coupling Operator, and Nominated Electricity Market Operators. The Nominated Electricity Market Operators shall immediately publish a notification to all Market Participants.
5. In such cases, capacity shall be provided by the Coordinated Capacity Calculator no later than the Day Ahead Market Gate Closure Time.

**Article 57**

**OPERATION OF THE DAY AHEAD ELECTRICITY MARKET**

1. The Day Ahead Electricity Market shall open no later than 11.00 Market Time D-1.
2. Orders shall be submitted by Market Participants in accordance with Article 49, to Nominated Electricity Market Operators before Day Ahead Market Gate Closure. Nominated Electricity Market Operators shall ensure that all Orders are anonymized before being forwarded to Market Coupling Operators.
3. Nominated Electricity Market Operators shall submit Orders received in accordance with paragraph 2 to Market Coupling Operators no later than a time specified by Market Coupling Operators in the proposal for a single Price Coupling Algorithm according to Article 46(3).
4. The Day Ahead Market Gate Closure Time in each Bidding Zone shall be noon D-1 Market Time.

**Article 58**

**DELIVERY OF RESULTS**

1. Market Coupling Operators shall use best endeavours to deliver the Price Coupling Algorithm results:

1. specified in Article 49 (2) (a) and 49 (2) (b), to all System Operators, Coordinated Capacity Calculators, Nominated Electricity Market Operator and Market Information Aggregators; and
2. specified in Article 49 (2) (c) to all Nominated Electricity Market Operators.

 simultaneously and no later than the time specified by System Operators in their requirements according to Article 46 (1) (a).

1. System Operators shall verify that the results of the Price Coupling Algorithm specified in Article 49 (2)(b) have been calculated in accordance with the net positions specified in accordance with Article 49(2)(b).
2. Nominated Electricity Operators shall verify that the results of the Price Coupling Algorithm specified in Article 49 (2)(c) have been calculated in accordance with the Orders submitted in accordance with Article 57(3).

**Article 59**

**CALCULATION OF SCHEDULED EXCHANGES**

1. Where notifications of Scheduled Exchanges are required by System Operators, the Scheduled Exchange Calculator shall calculate for each Market Time Period Scheduled Exchanges in accordance with the methodology set forth in accordance with Article 53 as soon as reasonably practicable, but no later than 15:30 Market Time D-1 .
2. The Scheduled Exchange Calculator shall notify the Market Coupling Operator, Central Counter Parties Market Information Aggregator(s) and System Operators of the agreed Scheduled Exchanges.

**Article 60**

**INITIATION OF FALLBACK PROCEDURES**

1. In the event that Market Coupling Operators, having used best endeavours, is unable to deliver part or all of the results of the Price Coupling Algorithm by the time specified in accordance with Article 46 (1) (a), fallback procedures as established in accordance with Article 55 shall be followed.
2. In cases where the Market Coupling Operators are unable to deliver part or all of the results, the Market Coupling Operators shall notify Nominated Electricity Market Operators and the Market Information Aggregator(s) as soon as an issue is identified. The Market Operators shall use best endeavours to provide a notification to Market Participants that fallback procedures may be followed.

**Article 61**

**PUBLICATION OF MARKET INFORMATION**

1. For each Bidding Zone and for each Market Time Period as soon as reasonably practicable following the receipt of information from the Market Coupling Operator as defined in Article 58 Scheduled Exchange Calculators as defined in Article 59 or Coordinated Capacity Calculators as defined in Article 56, and no later than 15:30 Market Time D-1, the Market Information Aggregator shall, having first entered into appropriate commercial arrangements with the entity which is able to generate the data, publish on a central platform at minimum:
2. Net positions;
3. Clearing Prices;
4. Scheduled Exchanges where available;
5. Day Ahead Cross Zonal Capacities; and
6. Notification of the application of fallback
7. Nominated Electricity Market Operators shall inform Market Participants on their execution status and Clearing prices of their Orders.
8. The Market Information Aggregator shall ensure that historical data for a period of not less than 5 years (where available) is freely available in an accessible format to Market Participants.

**CHAPTER 5**

**THE INTRADAY ELECTRICITY MARKET**

**SECTION 1**

 **OBJECTIVES, FUNCTIONALITY AND RESULTS FROM THE INTRADAY MARKET**

**Article 62**

**OBJECTIVES OF THE CONTINUOUS TRADING MATCHING ALGORITHM**

1. As from the Intraday Cross Zonal Gate Opening Time and prior to the Intraday Cross Zonal Gate Closure Time, the Continuous Trading Matching Algorithm shall determine which Orders to select for Matching such that it:
2. Maximises Economic Surplus per trade for the Intraday timeframe by allocating implicitly capacity to Orders which it is feasible to Match in accordance with the price and time of submission.
3. Respects Allocation Constraints provided in accordance with Article 66 (4);
4. Respects Cross Zonal Capacities as specified in Article 66 (1);
5. Respects requirements for the delivery of results as referred to in Article 68; and
6. Is repeatable and scalable.
7. The Continuous Trading Matching Algorithm shall produce the results specified in Article 63 and meet the capabilities and functionalities provided in accordance with Article 64.

**Article 63**

**Results of the Continuous Trading Matching Algorithm**

1. The Market Coupling Operator shall ensure that the Continuous Trading Matching Algorithm shall perform the Matching of Orders resulting in, at a minimum:
2. Execution status of Orders and price(s) per trade; and
3. Net Positions for each Market Time Period within the Intraday timeframe.
4. The Market Coupling Operator shall use best endeavours to ensure the accuracy and efficiency of results produced by the single Continuous Trading Matching Algorithm.
5. The Market Coupling Operator shall use best endeavours to ensure that results are compliant with the objectives specified in Articles 4 and 62
6. System Operators shall verify that the results of the Continuous Trading Matching Algorithm are consistent with the Net Positions and Allocation Constraints specified in Article 66.

**Article 64**

**Products accommodated**

1. Nominated Electricity Market Operators shall ensure that all Orders submitted to the Market Coupling Operator are expressed in terms of Euro and make reference to Market Time.
2. Nominated Electricity Market Operators shall ensure that products shall be compatible with the characteristics of the Cross Zonal Capacities allowing them to match simultaneously or shall be tradable only inside a Bidding Zone.
3. Nominated Electricity Market Operators shall periodically and at least every 2 years, consult with relevant stakeholders, in order to ensure that the available products reflect Market Participants` needs and promote the objectives specified in Articles 4 and 62. This shall be done in close cooperation with the System Operators.
4. The Market Coupling Operator shall ensure that the Continuous Trading Matching Algorithm is able to accommodate Orders covering one Market Time Period and multiple Market Time Periods.
5. In the event that the Market Coupling Operator, Nominated Electricity Market Operators, System Operators or National Regulatory Authorities consider that the introduction of maximum and minimum prices, and the amendment of maximum and minimum prices if such prices have previously been introduced, to the Intraday market could fail to facilitate the objectives specified in Articles 4 or 62, they shall notify the Market Coupling Operator who shall, as soon as reasonably practicable but no later than 3 months after the point at which the impact is identified, propose and consult on harmonised maximum and minimum bid price to be applied in all Bidding Zones covered by this Network Code.

**Article 65**

**PRICING OF INTRADAY CAPACITY**

1. Intraday Cross Zonal Capacity shall be priced to reflect Market Congestion.
2. Where appropriate, Intraday capacity pricing shall be included within the Continuous Trading Matching Algorithm.
3. In order to reflect the actual specific network and market situation, the Intraday Cross Zonal Capacity price shall be based on actual Orders

**SECTION 3**

**THE INTRADAY MARKET PROCESS**

**Article 66**

**CAPACITY CALCULATION AND ALLOCATION CONSTRAINTS**

1. The Coordinated Capacity Calculator shall ensure that Cross Zonal Capacity shall be provided to the Market Coupling Operator as soon as reasonably practicable but not later than 15 minutes prior to the Intraday Cross Zonal Gate Opening Time.
2. System Operators shall notify the Coordinated Capacity Calculator if updates are required to the Cross Zonal Capacity, due to operational changes on the transmission network. The Coordinated Capacity Calculator shall then notify the Market Coupling Operator.
3. If, for reasons beyond the reasonable control of the Coordinated Capacity Calculator, the Coordinated Capacity Calculator is unable to comply with paragraph 1, the Coordinated Capacity Calculator shall notify the Market Participants, the Nominated Electricity Market Operator and the Market Coupling Operator.
4. System Operators shall provide Allocation Constraints to the Market Coupling Operator no later than 15 minutes prior to the Intraday Cross Zonal Gate Opening Time.

**Article 67**

**Operation of the Intraday market**

1. System Operators shall be responsible for setting the Intraday Cross Zonal Gate Opening and Intraday Cross Zonal Gate Closure Time.
2. All Orders for a given Market Time Period shall be submitted by Market Participants to Nominated Electricity Market Operators before the Intraday Energy Gate Closure Time. In order to have access to Cross Zonal trading, Orders for a given Market Time Period shall be submitted by Nominated Electricity Market Operators to the Market Coupling Operator before Intraday Cross Zonal Gate Closure Time.
3. Nominated Electricity Market Operators shall ensure anonymity when submitting Orders to the Shared Order Book.
4. The Intraday Cross Zonal Gate Closure Time shall be set to:
5. maximize Market Participants’ opportunities for adjusting their balances by trading in the Intraday timeframe as close as possible to real time; and
6. provide System Operators and Market Participants sufficient time for their scheduling and balancing processes in respect of network and system security.
7. The Intraday Cross Zonal Gate Closure Time shall be at the maximum one hour prior to the start of the relevant Market Time Period and must respect the related balancing processes related to system security.

**Article 68**

**DELIVERY OF RESULTS**

1. The Market Coupling Operator shall use best endeavours to deliver the results of the Continuous Trading Matching Algorithm as specified in Article 63 (1) (a) to Nominated Electricity Market Operators. In the event that the Market Coupling Operator, having used best endeavours, is unable to deliver these Continuous Trading Matching Algorithm results, the Market Coupling Operator shall notify Nominated Electricity Market Operators.
2. The Market Coupling Operator shall use best endeavours to deliver the Continuous Trading Matching Algorithm results as specified in Article 63 (1) (b) to the System Operators and Nominated Electricity Market Operator. In the event where the Market Coupling Operator, having used best endeavours, is unable to deliver these Continuous Trading Matching Algorithm results, the Market Coupling Operator shall notify as soon as reasonably practicable the System Operators and the Scheduled Exchange Calculator. System Operators and the Scheduled Exchange Calculator shall notify concerned entities.
3. Nominated Electricity Market Operators shall as soon as reasonably practicable send the necessary information to Market Participants to ensure that necessary post-trading actions can be undertaken.

**Article 69**

**CAlculation of SCHEDULED EXCHANGES**

1. In situations where notifications of Scheduled Exchanges are required by System Operators, as soon as reasonably practicable after the entry into force of this Network Code and no later than 12 months from that date, System Operators shall define and publish a single methodology to be used in calculating Scheduled Exchanges between Bidding Zones following the Matching of Orders. The calculation of Scheduled Exchanges shall be based on the Continuous Trading Matching Algorithm results as specified in Article 63 (1) (b) and shall respect the principles of transparency and non-discrimination.
2. System Operators shall provide this methodology to the Scheduled Exchange Calculator and System Operators shall ensure that the Scheduled Exchange Calculator is able to produce the Scheduled Exchanges specified by this methodology.
3. The Scheduled Exchange Calculator shall, in accordance with this methodology, calculate Scheduled Exchanges each Market Time Period and notify them to the Market Coupling Operator, System Operators and Central Counter Parties as soon as reasonably practicable in accordance with the specifications established by System Operators.

**Article 70**

**Publication of Market information**

1. Each Nominated Electricity Market Operator shall publish, as soon as Matched, at a minimum, the anonymised results per Trade of the Continuous Trading Matching Algorithm in accordance with Article 63 (1) (a).
2. Each Nominated Electricity Market Operator shall ensure that historical data with respect to market information in this article is publicly available in an accessible format to Market Participants for a period of not less than 5 years (where such historical data exists).

**Article 71**

**COMPLEMENTARY REGIONAL AUCTIONS**

1. Where implemented, complementary regional auctions shall be subject to approval by National Regulatory Authorities and shall only be approved if the following conditions are met:
2. Regional auction shall not have an adverse impact on the liquidity of the pan-European Intraday solution;
3. All Cross Zonal Capacity shall be allocated through the Capacity Management Module;
4. The regional auction shall not introduce any discrimination between Market Participants from adjacent regions; and
5. The timescales for regional auctions shall be consistent with the pan-European Intraday solution to enable the Market Participants to trade as close as possible to real-time.
6. National Regulatory Authorities shall have consulted the Stakeholder Committee.
7. National Regulatory Authorities shall periodically, but at least every 2 years, review the compatibility between any regional solutions and the pan-European Intraday solution to ensure the conditions above continue to be fulfilled.

**CHAPTER 6:**

**CLEARING AND SETTLEMENT FOR THE DAY AHEAD AND INTRADAY MARKETS**

**Article 72**

**CLEARING AND SETTLEMENT**

Central Counter Parties shall perform clearing and settlement activities in a manner which promotes the achievement of the objectives specified in Article 4 in a timely manner.

**Article 73**

**CLEARING AND SETTLEMENT WITH MARKET PARTICIPANTS**

* 1. The Central Counter Parties appointed in accordance with Article 74 shall ensure the clearing and settlement of all Matched Orders. The Central Counter Parties shall act as the counterparty to Market Participants for all their trades with regard to the financial rights and obligations arising from these trades. Central Counter Parties shall respect the principles of transparency and non-discrimination.
	2. The Central Counter Parties shall maintain anonymity between Market Participants.

**Article 74**

**CROSS ZONAL CLEARING AND SETTLEMENT**

* 1. Central Counter Parties shall act as counterparty to each other for the exchange of energy between Bidding Zones with regard to the financial rights and obligations arising from these energy exchanges.
	2. Such exchanges shall take into account:
1. Net Positions as defined in Articles 49 (2) (b) and 63 (1) (b); and /or
2. Scheduled Exchanges as defined in Articles 59 and 69.
	1. Central Counter Parties shall ensure that for each time period:
3. across all Bidding Zones, taking into account, where appropriate, Allocation Constraints, there are no deviations between the sum of energy transferred out of all Bidding Zones and the sum of energy transferred into all other Bidding Zones; and
4. electricity exports and electricity imports between Bidding Zones equal each other. Deviations may only result from considerations of, Allocation Constraints, where appropriate.
	1. Notwithstanding paragraph 1 above, a Shipping Agent may act as a counterparty between different Central Counter Parties for the exchange of the energy. Such cases shall be subject to the conclusion of a specific agreement between involved parties and shall be subject to approval by National Regulatory Authorities.

Shipping Agents shall:

1. enter into buy/sell transactions with the Central Counter Parties for energy corresponding with Scheduled Exchanges; and
2. collect any Congestion Income arising from such trades.
	1. Central Counter Parties or Shipping Agents shall collect Congestion Incomes arising from the trades specified in Article 56 to 58 for the Day Ahead Market and in accordance with Articles 66 to 68 for the Intraday Market.
	2. Central Counter Parties or Shipping Agents shall ensure that Congestion Incomes resulting from the trades set out in paragraph 3 are provided to the Congestion Income Distributor no later than 2 weeks after the date of settlement.
	3. In the event that timing of payments is not harmonized between two bidding zones, involved Member States shall ensure an entity is appointed to manage the timing mismatch and face related costs.

**Article 75**

**CONGESTION INCOME DISTRIBUTION**

1. The Congestion Income Distributor shall distribute Congestion Incomes received in accordance with Article 74 (6) in accordance with the methodology(ies) established pursuant to Article 81 as soon as reasonably practicable and no later than one week after the transfer of Congestion Incomes.

**Chapter 7**

**FIRMNESS OF ALLOCATED CROSS ZONAL CAPACITY**

**Article 76**

**THE DAY AHEAD FIRMNESS DEADLINE**

1. No later than 12 months after the entry into force of this Network Code, all System Operators shall jointly develop a proposal for a single Day Ahead Firmness Deadline.
2. In all cases, the Day Ahead Firmness Deadline shall be set at half an hour or more before the Gate Closure Time of the Day Ahead Market.

**Article 77**

**AMENDMENT OF THE DAY AHEAD FIRMNESS DEADLINE**

1. In the event that System Operators jointly identify a need to amend the Day Ahead Firmness Deadline, they shall produce a proposal.
2. The proposal shall be consulted on in accordance with Article 5, submitted to National Regulatory Authorities in accordance with Article 8 and published in accordance with Article 6.

**Article 78**

**FIRMNESS OF DAY AHEAD CAPACITY & ALLOCATION CONSTRAINTS**

1. Prior to the Day Ahead Firmness Deadline the Coordinated Capacity Calculator shall be entitled to adjust Cross Zonal Capacities and System Operators shall be entitled to adjust Allocation Constraints provided to the Market Coupling Operator.
2. After the Day Ahead Firmness Deadline all Cross Zonal Capacities and Allocation Constraints shall be firm.
3. If Cross Zonal Capacities or Allocation Constraints have not been provided before the Day Ahead Firmness Deadline they shall become firm as soon as they have been submitted to the Market Coupling Operator.
4. After the Day Ahead firmness deadline Cross Zonal Capacities which have not been allocated may be adjusted for subsequent allocations.

**Article 79**

**FIRMNESS OF INTRADAY CAPACITY**

Cross Zonal Capacities shall be firm as soon as they have been Allocated.

**Article 80**

**FIRMNESS IN THE CASE OF FORCE MAJEURE OR EMERGENCY SITUATIONS**

1. In the event of a Force Majeure situation or an Emergency Situation, System Operators shall, have the right to curtail Cross Zonal Allocated Capacities. In all cases, curtailment shall be undertaken in a coordinated manner having liaised with all directly affected System Operators.
2. The System Operator which invokes Force Majeure shall publish a notification describing the nature of Force Majeure and its probable duration.
3. Allocated Capacities which become subject to a Force Majeure shall be reimbursed for the period of that Force Majeure in accordance with the following arrangements:
4. In the event that capacity was allocated implicitly, Central Counter Parties or Shipping Agents or Market Participants shall not be subject to financial damages or financial benefits arising from any imbalance created by such curtailment; or
5. In the event that capacity was allocated explicitly, Market Participants shall be entitled to compensation equal to the value of the capacity set during the Explicit Allocation process.
6. The System Operator which invokes Force Majeure shall make every possible effort to limit the consequences and duration of the Force Majeure.

**Chapter 8**

**CONGESTION INCOME DISTRIBUTION**

**Article 81**

**ESTABLISHMENT OF CONGESTION INCOME DISTRIBUTION ARRANGEMENTS**

1. No later than 12 months after the entry into force of this regulation, all System Operators shall establish a methodology for sharing Congestion Income.
2. The methodology(ies) developed pursuant to paragraph 1 shall:
3. facilitate the efficient long-term operation and development of the pan-European electricity transmission network and the efficient operation of the pan-European electricity market;
4. facilitate the achievement of the general principles of congestion management as specified in Article 16 of Regulation 714/2009;
5. allow for reasonable financial planning;
6. be compatible across timeframes; and
7. establish arrangements to share Congestion Income deriving from transmission assets owned by parties other than System Operators.

**Article 82**

**AMENDMENTS TO CONGESTION INCOME DISTRIBUTION ARRANGEMENTS**

1. Where System Operators identify a need to amend the methodology(ies) established pursuant to Article 81 they shall:
2. Develop a proposal agreed by relevant System Operators; and
3. Demonstrate how the proposal better facilitates the achievement of the principles specified in Article 81(2).

**Chapter 9**

**Article 83**

**REDISPATCHING OR COUNTERTRADING COST SHARING METHODOLOGY**

[Being worked on with ACER]

**Article 84**

**AMENDMENTS TO THE REDISPATCHING OR COUNTERTRADING COST SHARING METHODOLOGY**

[Being worked on with ACER]

**Chapter 10**

**CAPACITY ALLOCATION AND CONGESTION MANAGEMENT COSTS**

**Article 85**

**GENERAL PROVISIONS**

1. The costs related to the obligations allocated to Transmission System Operators in accordance with Article 9, including but not limited to the costs specified under Articles 86 to 90, shall be approved only if they are reasonable and proportionate.
2. Costs approved in accordance with Paragraph 1 shall be recovered in a timely manner via network tariffs or appropriate mechanisms as determined by National Regulatory Authorities.
3. If requested to do so by National Regulatory Authorities, any party defined in Article 1, shall, within 3 months of such a request, use best endeavours to provide such information as reasonably requested by National Regulatory Authorities to facilitate the assessment of the reasonableness and proportionality of costs incurred.
4. Information on costs pursuant to this Article and pursuant to Articles 86 to 90 shall not be subject to the consultation provisions of Article 5 or transparency provisions of Article 6.

**Article 86**

**COSTS OF ESTABLISHING AND AMENDING MARKET COUPLING ALGORITHMS**

1. The Market Coupling Operators shall bear:
2. the costs of establishing, updating or further developing the Price Coupling Algorithm for the Day Ahead Electricity Market;
3. the costs of establishing, updating or further developing the Continuous Trading Matching Algorithm.
4. System Operators, subject to agreement with the Market Coupling Operator, shall be entitled to make a contribution to the costs described in paragraph 1. In such a case, System Operator(s) shall within 2 months of receiving a forecast from the Market Coupling Operator, be entitled to provide a joint cost contribution proposal to the relevant National Regulatory Authorities for approval.
5. In this case the Market Coupling Operators shall, when submitting a proposal pursuant to paragraph 2, provide a forecast to System Operators for each of the costs described in paragraph 1.
6. The Market Coupling Operators shall be entitled to recover costs pursuant to paragraph 1 which have not been borne by System Operators pursuant to paragraph 2 by means of fees or other appropriate mechanisms only if they are reasonable and proportionate.

**Article 87**

**COSTS OF ESTABLISHING AND OPERATING COORDINATED CAPACITY CALCULATION PROCESSES**

1. Each System Operator shall bear the costs related to the provision of inputs to the Capacity Calculation Process.
2. All System Operators shall bear costs related to the establishment and operation of the European Merging Function.
3. All System Operators of each Capacity Calculation Region shall bear costs related to the establishment and operation of the Coordinated Capacity Calculators.
4. Any costs incurred by Market Participants in meeting the requirements of this Network Code shall be borne by those Market Participants.

**Article 88**

**COSTS OF OPERATING THE DAY AHEAD AND INTRADAY MARKET PROCESSES**

1. All costs incurred by the Market Coupling Operator in operating the Day Ahead and Intraday Processes as defined in Articles 45 to 61 and Articles 62 to 71 shall be recovered from Nominated Electricity Market Operators.
2. The Nominated Electricity Market Operators shall be entitled to recover costs pursuant to paragraph 1 by means of fees or other appropriate mechanisms only if they are reasonable and proportionate.

**Article 89**

**CLEARING AND SETTLEMENT COSTS**

1. All costs incurred by Central Counter Parties shall be recoverable by means of fees or other appropriate mechanisms only if they are reasonable and proportionate.
2. Shipping Agents shall not be subject to fees nor be required to provide collateral.

**Article 90**

**COSTS OF ENSURING FIRMNESS**

1. The costs of ensuring firmness in accordance with Articles 76 to 80 shall be borne by System Operators. These costs shall include, but shall not be limited to: the costs of Redispatching, Countertrading, correcting imbalances, incurred market mechanism imbalance costs and compensation mechanisms associated with ensuring firmness.

**TITLE 3**

**TRANSITIONAL ARRANGEMENTS**

**Chapter 1**

**TRANSITIONAL INTRADAY ARRANGEMENTS**

**Article 91**

**GENERAL PROVISIONS**

The transitional arrangements shall, as far as reasonably practicable, promote the objectives specified in Article 4 in the Explicit Allocation of Intraday Capacity.  The arrangements shall be compatible and, as far as possible consistent with, the arrangements specified in Articles 62 to 71.

**Article 92**

**EXPLICIT ALLOCATION**

1. System Operators shall provide Explicit Allocation by means of the Capacity Management Module on those Bidding Zone Borders where they are requested to do so by relevant National Regulatory Authorities. In such cases, System Operators shall publish the conditions that must be fulfilled by Market Participants to participate in the Explicit Allocation. These conditions shall be subject to approval by the relevant National Regulatory Authorities in accordance with Article 8.
2. The Capacity Management Module shall avoid discrimination when allocating implicitly and explicitly capacity at the same time, by determining which Orders to select for Matching and which explicit capacity requests to accept, according to a compatible ranking of price and/or time of entrance such that it maximises Economic Surplus per trade for the Intraday timeframe.

**Article 93**

**REMOVAL OF EXPLICIT ALLOCATION**

1. Nominated Electricity Market Operators shall cooperate closely with System Operators and shall consult Market Participants in order to translate the needs of Market Participants linked with Explicit Capacity Allocation rights into Sophisticated Products.
2. Prior to the removal of Explicit Allocation, National Regulatory Authorities shall organize a consultation to assess whether the proposed Sophisticated Products are well understood by Market Participants and whether they fulfil their needs for Intraday trading.
3. Concerned National Regulatory Authorities shall approve the introduction of Sophisticated Products and the removal of Explicit Allocation.

**CHAPTER 2**

**OBJECTIVES AND PROVISIONS OF THE TRANSITIONAL INTRADAY ARRANGEMENTS**

**Article 94**

**BIDDING ZONE BORDER-SPECIFIC PROVISIONS, POST-TRADING OBLIGATIONS AND TRANSPARENCY**

1. Capacity Traders shall comply with the approved conditions for Explicit Allocation developed pursuant to Article 92.

1. Capacity Traders shall be fully responsible and liable for the completion of the post-trading obligations related to the Cross Zonal exchanges.
2. Capacity Traders shall be fully responsible and liable for fulfilling the financial rights and obligations, if any, relating to settlement arising from the Explicit Allocation.
3. System Operators shall publish the relevant interconnection(s) where Explicit Allocation is applicable, the Cross Zonal Capacity for Explicit Allocation and other relevant information.

**Article 95**

**EXPLICIT REQUESTS FOR CAPACITY**

1. The Explicit request for capacity can only be submitted by a Capacity Trader for an interconnection where the Explicit Allocation is applicable. For each Explicit request for capacity the Capacity Trader shall submit the volume and the price to the Capacity Management Module. The price and volume of Explicit Allocated Capacity shall be made publicly available.

**CHAPTER 3**

**ISLAND SYSTEMS WITH CENTRAL DISPATCH**

**Article 96**

**TRANSITIONAL ARRANGEMENTS FOR ISLAND SYSTEMS WITH CENTRAL DISPATCH**

1. The requirements of this Network Code shall not apply to Transmission System Operators in the Republic of Ireland and Northern Ireland, operating island systems with central dispatch, until 31 December 2016.
2. From the date of the entry into force of this Network Code until 31 December 2016 Transmission System Operators in the Member States referred to in paragraph 1 shall implement arrangements intended to ensure full implementation of and compliance with this Network Code by 31 December 2016. Those arrangements shall:
3. facilitate the transition to the full implementation of and compliance with this Network Code;
4. be justified on the basis of a cost-benefit analysis;
5. not unduly affect other jurisdictions;
6. guarantee a reasonable degree of integration with the markets in adjacent jurisdictions;
7. provide for at least:
	1. allocation of interconnector capacity in a day-ahead explicit auction and  in at least two intraday implicit auctions;
	2. joint nomination of interconnection capacity and energy at the day-ahead timeframe;
	3. application of the “Use-It-Or-Lose-It” or “Use-It-Or-Sell-It” principle to capacity not used at the day-ahead timeframe.
8. fair and non-discriminatory pricing of interconnector capacity in the intraday implicit auctions;
9. fair, transparent and non-discriminatory compensation mechanisms for ensuring firmness;
10. set out a detailed roadmap, approved by the regulatory authorities for Ireland, Northern Ireland and Great Britain, of milestones for achieving full implementation of and compliance with this Network Code;
11. be subject to a consultation process involving all relevant parties and give utmost consideration to the consultation’s outcome.
12. The National Regulatory Authorities for Ireland, Northern Ireland and Great Britain shall provide to the Agency regularly, but at least quarterly, or upon the Agency’s request, any information required for assessing the transitional arrangements for the electricity market on the island of Ireland and the progress towards achieving full implementation of and compliance with this Network Code.

**Title 4**

**FINAL PROVISIONS**

**Article 97**

**ENTRY INTO FORCE**

1. This Network Code shall enter into force on the twentieth day following that of its publication in the Official Journal of the European Union.