Approved by ERE Board Decision No. 186, Date 10.11.2017.

TRANSMISSION NETWORK CODE

This document, named "Transmission Network Code" is drafted by OST Company, pursuant to provisions of Law No.43 / 2015, dated 30.04.2015 "On Power Sector" and in accordance with the provisions of Grid Codes and Operational Handbook of ENTSO-E.

Introduction

In accordance with national legal framework, National Energy Strategy, the regulatory framework and Albania's commitment to the security of energy supply, economic development, investment and social stability as part of the Energy Community, as a product of the collaboration of all stakeholders in the power sector is drafted the Transmission Network Code .

In view of the foregoing, this document intends primarily to contribute to the transmission system network management on a non-discriminatory basis for all existing or new grid users and to serve in achieving the objectives of Energy Strategy including implementation and liberalization of the power sector.

This document is intended to achieve a planned, coherent and coordinated operation between Transmission System Operator and all network users of transmission system in order to establish the best possible conditions for development and operation of an integrated and effective electricity market.

Transmission Network Code addresses issues related to Transmission System Operator, planning and operation of the power system as a whole and access of energy market stakeholders in transmission network of OST sh.a

Transmission Network Code sets norms, rules, procedures, essential and general requirements leading to the operation and development of the country's power system.

Content

CHAPTER I

INTRODUCTION AND GENERAL PROVISIONS

Article 1. Subject matter and scope

1. Transmission Network Code addresses the process of Transmission Network Planning, Connection to network of grid users, operational planning and scheduling of grid users / participants of the Energy Market, Operation and Dispatching of Transmission Grid Users, Operation of the Electricity Market and Power System balancing, as well as in normal and emergency states. These processes cover different time horizons from long-term planning (up to 10 years) to operational planning (up to 1 year), operation and real time dispatching and the time after the occurrence of an event (failure).
2. Overall objective of this Code is to guarantee that chapters of this Network Code operates jointly, in fullycoherence with the Metering Code, Distribution System Network Code, Model and Market Rules and provisions of Operational Handbook of ENTSO-E.
3. Transmission Network Code aims to:
   a) allow OST sh.a to carry out planning, developing, maintaining,utilization, operation of power system in our country economically and in an efficient way, according to requirements for power supply in Albania and Regional Power Market; and
   b) allow OST company to comply with bi /multilateral agreements regarding interconnection and cross-border power flows with neighboring TSO's or beyond, through ENTSO-E network; and
   c) avoid discrimination between transmission grid users / participants of electricity market during relevant processes for the implementation of Grid Code provisions

Article 2. Content of the Grid Code

Transmission Network Code is a regulatory secondary legislation act, for normal operation of the country's power system. It clearly defines the boundaries of ownership assets, and operational management margins between OST and Transmission Grid Users or market participants of the electricity market, it establishes the norms (rules, technical standards, etc.) of transmission system network operation and development, in accordance with electricity market development in Albania and Region. The Code establishes procedures of relationship between OST and transmission grid users / participants of the energy market.

Article 3. Approval, implementation, monitoring and updating of Grid Code

1. Transmission Network Code shall be approved by ERE, and its implementation is subject to continuous monitoring by ERE. Its review and update shall be carry out in accordance with the relevant legislation in force.
2. Transmission Network Code shall be developed, updated and administered by OST Company, which in turn will reflect in an adequate way and time, amendments to the legal framework affecting the Grid Code, informing and offering to grid users the opportunity to present their point of views and getting approval of ERE.

3. Transmission Network Code is mandatory for OST and all transmission grid users / participants of the electricity market.
4. Transmission Network user that fails to comply with any provision of the Grid Code, immediately informs OST about the reasons of failure. OST shall report to ERE the repetitive cases, with a proposal for penalty according to effective laws in force, to de-energisation or disconnection of the relevant grid user from transmission network.
5. A Transmission Network User that repeatedly does not comply with the provisions of the Grid Code retains the solely responsibility and consequences of de-energisation of connection or disconnection, which includes the cost of damages, compensation for the effects on clients and any other charge arising from this Code provisions and / or legislation on force.
6. In certain circumstances, not foreseen in this Code, OST can act decisively in response of obligations and legal rights to make possible the right management regimes or technical-operational situations in country's power system, considering and implementing the provisions of ENTSOE Grid Codes.
7. OST is the legal administrator of Transmission Network Code
8. OST shall:
   a) assess any serious failure in the system based on those analysis to review constantly Transmission Network Code,
   b) issue instructions to the interpretation and implementation of the Transmission Network Code.
9. OST in the role of Code's legal administrator of the:
   a) requires from grid users, that planning and operation of their assets to be based on the implementation of Grid Code provisions.
   b) monitors, inspects, tests or collects needed information by transmission network users to supervise the implementation of Grid Transmission Code by these users.
   c) prepares a detailed annual report concerning the administration and implementation of the Transmission Network Code., which shall be sent to ERE within January of the following year, for the previous year including:
      i. proposals for reviewing and updating of Transmission Network Code.;
      ii. written statements or objections raised by grid users during Network Code implementation and proposals for reviewing or updating.
10. During implementing of its obligations according to Transmission Network Code, OST sh.a is based on information provided by Transmission Grid Users or electricity market participants, regarding requirements and goals. OST is not responsible for consequences arised from judgments and actions based on information provided by Transmission Grid Users regarding their requirements and objectives.

Article 4. Transmission System Network

1. Transmission Network is administered by Transmission System Operator of OST sh.a, which is licensed for carrying out of legal activity of power transmission via mains high voltage (110 kV, 150 kV, 220 kV , 400 kV).
2. The Transmission System Operator, OST sh.a perform its activity, as Transmission System operator and Market Operator according to the provisions of Law no. 43/2015 "On Power Sector", Market Model and Market Rules in force.
3. Assets managed by OST sh.a are:
   a) All 400, 220,150 and 110 kV lines including switching devices and their installations .
   b) 400/220/110 kV substations; 400/220 kV; 400/110 kV; 220/110 / TM kV; 220 / MV kV and 110 / MV busbars of Distribution Operator, up to the metering point at the 110 kV power transformers 110 / MV of Distribution Operator substations.

c) 220 kV substations of HHP’s V.Dejes, Koman and Fierze except 220 kV generators outputs, up to 220 KV busbar breakers, 110 kV / 150 kV including 150 kV output of the overhead line and 110/150 kV step up transformer in Bistrica 1 Hydropower Substation.

Article 5. Mutual access and technical safety

1. All Transmission Network Users guarantee to OST sh.a, (experts or groups of specialists) the right of physical access to their premises and technical relevant documentation, to perform various services and necessary facilities too, for accomplishment of OST responsibilities (rights and obligations).
2. OST and transmission grid users are responsible for granting mutual access in their relevant properties, according to an agreed list of authorized persons which shall have access and carry out different works in mutual properties of Parties.
3. OST and Transmission System Grid Users shall define in special agreements a list of electrical equipment owned by either Party, installed in the ownership of the other party (e.g measurement equipment, telecommunications, SCADA, power cables etc.). In this agreement are attached ownership plans as described in the Connection Code of this document, jointly with accessed roads.
4. Transmission System Grid Users are responsible for safety and enforcement of working rules of Technical Safety on their properties.
5. Work performed on devices / equipment group is considered terminated when the services rendered and security measures are in conformity with the norms and technical safety rules and technical exploitation in use. Only than, the device / group of devices can be operated .
6. All Transmission Grid Users follow the instructions and guidelines issued by OST. Transmission System Grid Users require approval by OST to perform the relevant operational activities.

Article 6. Communication between OST and the transmission grid users

1. All communications between OST and transmission grid users / participants of energy market shall be in written form except certain cases where are required verbally, cases which shall be reflected in writing form as soon as possible. Where Transmission Network Code specifies disclosures in writing or confirmed in writing, any means of electronic transfer that enables the recipient to retain this information, such as email, messaging, computer, SCADA, fax, fulfills this provision of communication provided to guarantee the security of information and privacy protection, in accordance with the applicable legal framework.

Article 7. Confidentiality

1. In accordance with Transmission Network Code, OST sh.a will request and receive information from Transmission Network Users about their business activities (generation, distribution, supply or trade) while respecting the principles of confidentiality. OST do not give and do not publish information to third Parties without the written consent of the information owner, except as required by provisions of Transmission Network Code..
2. Data and information exchanged for a specific purpose should be used only for that purpose, except when both Parties agree on otherwise. OST sh.a shall be released from obligations under this article when the information should be published or through regular reporting or at the request of national institutions, ERE, other institutions, based on the relevant legal framework. In these circumstances OST shall notify the party that submitted the relevant data in each case.
3. When all parts or part of any function, specified in this Network Code is delegated by OST or a grid user to a third party, OST sh.a or Grid User shall ensure that the necessary confidentiality

agreements including the obligation to provide access to necessary information for monitoring by ERE, are submitted before the delegation.

Article 8. Dispute Settlement Procedures

1. In case of disputes between Transmission Grid Users and OST sh.a regarding the interpretation of a Grid Code provision, the conflict shall be ssettled based on procedures for disputes settlements established in the Grid Code.
2. In case of any conflict between any provision of Transmission Network Code and any contract or agreement between OST and Transmission Grid Users or Power Market participants, the provisions of Transmission Network Code shall prevail.
3. Notwithstanding of the dispute reasons, the parties to the dispute will not prevent the fulfillment of respective functions in accordance with provisions of Grid Code and relevant legal framework and shall not undertake action or refuse to perform operation, affecting Transmission System Operator security. Immediately, after arising a dispute, the Parties shall communicate to attain a solution in accordance with the document that governs bilateral relationship (Contract / Agreement) and Transmission Network Code..
4. Agreement between Parties that have different interpretations should be applied until ERE's announcement decision about the dispute.
5. If a dispute has been arisen by unaddressed problems of Transmission Network Code., the issue will be discussed between Parties, which must come up with an Agreement. If an agreement can not be attained, the Parties formulate a temporary operation agreement and then refer the matter to ERE, if the issue is not covered by the Grid Code. ERE's decision shall suspend the temporary operation agreement which is mandatory to be implemented by relevant Parties.
6. The deadline to attain an agreement or to resolve the dispute generated, shall be defined by Parties, by consensus.
7. If ERE's decision does not satisfy the Parties on the dispute, the issue shall be referred to relevant court.

Article 9. Unpredicted Events

1. In unpredicted circumstances or events, in any provision of the Grid Code, OST shall immediately call to a meeting all affected Parties by the resolution and actions which shall be undertaken in these circumstances.
2. If in this cases, no agreement or recommendation is attained, OST temporarily sets the actions to be undertaked, once opinions are submitted on the issues discussed by the Parties. OST sh.a as soon as possible refers the case to ERE.
3. The OST sh.a shall inform the Parties affected by a situation or event and/or issues orders for performing actions in order to preserve system operational security and to fulfill of its functions, in accordance with the established circumstances.
4. OST shall make transparent and inform Parties in a timely and appropriate manner, particularly ERE about unpredicted events, actions and/or instructions as well as assessment outcome of this event analysis.

Article 10. Partial Invalidity

1. If any article or part of article (paragraph or clause) that Transmission Network Code is declared invalid for any reason by ERE's decision, the validity of other Transmission Network Code provisions or part of intact Article, remains effective.

Article 11. Time periods of Majeure Force

1. In Majeure Force time periods, as prolonged dryness, floods, disruption of fuel supply,war, natural disasters,a certain abnormal situations defined, the Council of Ministers may issue directives for certain restrictions, controls and other rules. If they are contrary to the provisions of this Code, those provisions (articles, paragraphs or special clauses) of the Transmission Network Code, will be treated as temporarily suspended for all prolongation of this Force Majeure.

Article 12. Interim derogations

1. In cases that a Transmission Grid User can not meet completely and / or partially of the Grid Code requirements,it is obliged to request and immediately apply for interim derogation to OST and informing the ERE.
2. The request / application for interim derogation will contain the following information:
   a) The reason for the inability to meet the requirement / request / setting of the Grid Code partially and/or totally;
   b) Inability time duration of partially / fully satisfaction of the condition / request / provisions of the Grid Code;
   c) Assessment of the impact of the failure,in fulfilling the requirement / request / provisions of the Grid Code;
   d) The approximate date of return to normal state and the complete fulfillment of the requirement / request / grid code setting required for interim derogation.
3. OST shall consider the fulfillment of its obligations and operational security of transmission system network as well as all the facts submitted via application.
4. OST shall decide within 60 days whether or not a interim derogation is granted, specifying the period of validity and / its extension, but not more than 24 months, except in exceptional circumstances and with EREs approval .
5. In all cases, after the expiry of validity/extension of the interim derogation, the subject submits a new request, if the conditions of partial/complete compliance are not fullfilled yet, or are subject of a control/monitoring by OST according to Grid Code definitions, regarding normalization of previous situation of partial/complete non- compliance with relevant provisions of the Grid Code.
6. If a user/party, can not fulfill partially/fully the Grid Code requirements and fails to get approval for an interim derogation by OSTsh.a, OST sh.a may submit a appel to ERE.
7. If ERE confirms/allows the OST's decision for rejection of interim derogation request of a user / party, then OST applies the following measures:
   a) issues a written warning towards Transmission Grid User, for its obligation of fulfilling of Transmission Network Code provisions, and removal of partial/complete non-compliance within a reasonable period, but not more than 3 months, if the situation does not endanger the life and property of third Parties or Transmission System operational security;
   b) If the deadline specified according to point a) is not respected, OST shall issue a final warning for intervention, in accordance with the Transmission Network Code., to normalize the situation within 30 days.
   c) If the Transmission Grid User do not undertake measures within the period specified above, then OST will inform ERE and shall take actions till to de-energisation and disconnection of that user from Transmission System.
8. All costs incurred to third Parties and/or OST sh.a, by the failure of partially / fully fulfillment of the Grid Code provisions by a Grid user, which has failed in obtaining a interim derogation shall be borne by the user .

CHAPTER II

PLANNING CODE

Article 13. Subject matter and scope

1. Planning Code specifies and defines norms (standards, conditions, criteria, deadlines) for Network Transmission Development Plan by OST. Transmission Network Users shall carry out network development or modification plan of the their networks, consistent with compilation of long and middle term of OST's Plan of Transmission Network Development.
2. Planning according to provisions of the Code, the information exchange needed for planning, responsibilities for planning and development of Transmission System Network and the standards set forth in this Code are mandatory for grid users and energy market participants.
3. Network Development Plan of Transmission System (connection points in the property boundaries, lines and / or equipment, substations) and the power system in its entirety have to consider but not limited to, the following factors and conditions:
   a) Reconfiguration, reconstruction or optimization of parts of existing Transmission System network; developing / modifying of system/facility network users, connections of new grid users; expansion, increasing capacity and maintaining safety standards in accordance with forecasted increase of demand for active power and/or installing of a new system element
   b) Energy Community policies and objectives, EU and other organizations with a focus on power sector wherein Albania adheres, or is commited to respect the policies and objectives;and
   c) Transmission Network Development Plan should be in accordance with the Ten-Year Network Development Plan of ENTSO-E (TYNDP), other documents of ENTSO-E, Regional Investment Plans of ENTSO-E (RgIP) and Scenario Outlook and Adequacy Forecasts (SOAF).
   d) The cumulative effect of series of developments such as those mentioned above.

Article 14. Implementation of Planning Code

1. Planning Code shall be implemented obviously by OST and existing / perspective Transmission System Grid users as following:
   a. power generating modules with generating units connected to Transmission System Network, according to this code; and
   b. Distribution System Operator, OSHE;and
   c. Clients;and
   d. Owners of lines and interconnections;and
   e. Suppliers;

Article 15. Planning Criteria

1. OST and Transmission System Network Users shall plan the development of networks and systems/facilities in accordance with the criteria (N-1) of Operational Security, in determinist basis without limitations, justifications/financial arguments, considering, the less favorable generation profile model within relevant limits, while for the less probable situations (N-2) shall use an average model.
2. Estimations will be performed for the typical project lifestime of 35 years, unless otherwise dictated by life durability of facility or project plant.
3. Transient Stability should not be threatened in terms of successful protection actions after a single-phase fault/short circuits and in terms of short circuit or three-phase fault, or on the

busbar, disconnected within the normal operation of the protection action, without power system damages .

4. Lower economic cost criterion shall be applied in conditions when planning the connection of new grid users to the system and planning of investment for improving the reliability and/or quality of supply,to ensure the achievement of defined objectives and limits, and to determine and/or verify the desired reserve level of the network and/or its equipment.
5. Planning shall consider the value of load and generation in neighboring countries, reducing costs of services, regulatory guidelines, historical data on outages, load sheding, network constraints and supply quality indicators unfulfilled .
6. Long-term planning carried out by OST shall implement the criteria regarding long-term sustainability service provisions, which include:
   a) the right of servitude / expropriation;
   b) replacement of assets regarding to lifetime management planning of assets in accordance with the best practices of asset management;
   c) expansion projects and reinfrorcment of Transmission Network System which can not be justified by the criterion (N - 1).

Article 16. Long Term (10-year) Network Development Plan

1. OST shall develop a Long Term (10-year) Network Development Plan, in consultation with stakeholders and submits for approval by ERE. This Long Term (10-year) Network Development Plan, shall be coordinated with Ten Year Network Development Plan of ENTSO-E Network (TYNDP), applying its criteria and methodologies for long-term planning of transmission network system.
2. Long Term (10-year) Network Development Plan shall be updated every 2 years. This update, among other things, shall allow grid users to plan the expansion and development of their networks (systems / facilities).
3. Any grid user shall exchange with OST, information and data relating to the system/facility in accordance with Annex A.
4. The data to be received by OST from grid users shall be in formats defined in Planning Code.

Article 17. Planning and Development of Transmission System Network

1. Planning of generation, distribution system network, clients (demand) and energy suppliers will be based on Long Term (10-year) Network Development Plan of Transmission System.
2. Long-term development plan shall include forecasts for electricity demand, load in MW, maximum and minimum load of power system, additional generation capacites, lines and transmission capacities, substations and their transformation capacities, technical losses in transmission system network and other important parameters. Long-term Development Plan contains planning the development of interconnections connected with regional network,for exports and imports purposes, increasing the operational security, load sheding plan, increasing access of grid users and the efficiency of competitive power market.
3. OST will assess the needs for electricity based on data from the Distribution System Operator, and other clients of transmission system network. However, OST performs certain research analysis, to determine the needs for Active Power and Demand based on available historical data of OST.
4. Distribution System Operator on the basis of detailed analysis of demand, for all categories of its customers, shall submit to OST, requirements and needs for expansion, development of the network and demand. Similarly, shall act all other network Clients.
5. Distribution System Operator is responsible for providing technical detailed information for each user connected to its network and that could have a significant impact on the network.

6. The data shall be made available to OST by Clients and Power Generating Modules in a reasonable time which allows their use for the design of long-term plan. OST must be informed in an appropriate manner for any significant data change, in the forecasts submitted.
7. OST shall evaluate the technical losses in percentage and value for Transmission System Network in general, and detailed for network elements, as follows:
   a) Based on the assessment of power losses at peak (max) load of Transmission System network. This assessment will be carried out by researches and analysis of power flow distribution of power with different softwares assistance; and
   b) By conducting pilot studies and analysis,on specific elements of the transmission network and metering of electricity on both sides of the respective network element in conformity with the relevant standards and regulations of the Metering Code.
8. OST shall take into account the dynamics of economic development of the country (according to forecasting of increased gross domestic product GDP, investment, employment and consumption), changing of power consumption in various sectors of the economy, in order to establish the relation between economic development and energy demand.

Article 18. Generation Planning

1. Any producer must develop and submit a mid-term plan (every 2 years) and long term plan(10 years) for network development system /facility.

Article 19. Planning of Transmission System Network

1. OST develops the Long Term Development Plan of Transmission System Network taking into account the network developments, in systems/facilities of transmission grid users based on:
   a) power flow studies;and
   b) short circuit studies and analysis in network nodes and branches;and
   c) Static and Dynamic Stability Studies;and
   d) Non supplied energy studies, its quantity and costs;and
   e) optimal working regimes studies, in country's power system;and
   f) optimal working regimes studies, of merchant power flows, in transmission system.
2. OST shall prepare a 2-year mid-term plan, merely for development of transmission network (power lines, substations) of potential users needs for their access to transmission network.
3. OST prepare scenarios for development planning based on:
   a) Increased demand (uncertainties in forecasting of distribution system,OSHE demand and customers connected to transmission);and
   b) Location and installed capacity of new power generating modules;and
   c) Changes in hydrological conditions that cause changes in the import/export of energy;
   d) Regional transit capacities, NTC, in different directions of interconnection lines;
   e) RES integration.

Article 20. Planning of Distribution Network System

Distribution nework system operator, in an independent way shall develop its long and mid-term development plan and shall submit it to OST, in a fully coherent way and time horizons considering issues of System optimization.

Article 21. Development Planning Coordination of Transmission Network

1. OST shall coordinate planning of Grid Users based on data in the manner and time frames as described in the Transmission Network Code.
2. OST shall verify the validity and modify plans, if necessary, after studys and analysis of methodology, after comparison with factual and historical data and methodologies, consistent

with long-term network development planning of ENTSO-E, in order to consolidate and present, integrated Long-Term Development Plan for all grid users and energy market participants.

Article 22. Approval of the Long Term Development Network Plan

1. The draft of Long Term Network Development Plan developed by OST,shall be submitted for review and approval to ERE.
2. Long-term Development Plan shall become mandatory for implementation by OST, licensees, transmission grid users and the applicant for new connection, after approval by ERE.
3. Models, forecasts and conclusions of OST's study shall be presented in the relevant institutions in order to be integrated as part of regional investment plan of SEE (RgIP-Regional Investment Plan for Eastern Europe), Ten Year Network Development Plan ENTSO-E (TYNDP).
4. OST shall prepare its investiment plan of transmission network, based on long-term development plan.
5. OST publishes the Long Term Development Plan of the Transmission Network within 30 days after the ERE's approval, in its web site.

Article 23. General Planning information provided by OST sh.a

1. Transmission System Network data shall consists, on submission of existing Transmission System Network and Transmission System Network planned for future development, as described in the Mid and Long Term Development Plan. Such data shall include:
   a) Transmission Network planimetry scheme submitted in country map, showing the existing and planned network elements of Transmission System (indicated with points). Geographical map and the network scheme (digital or not) should be appropriate to the extent of reading;
   b) Single line diagram of Transmission System showing the existing and prospective elements (indicated in points) and connecting points of Generating Plants.
2. OST, on the request of grid users, provides information and data related a part of transmission network, to provide them opportunities, access to connection and use of Transmission System Network.
3. If required, OST shall also provide studies, reports and its analyzes on condition of that part of the transmission network, specified in the request.

Article 24. Cost of Data and Information

1. The OST shall have the right to ask Transmission Grid Users a fee for data or information related System Network and shall inform the grid user for this cost within 15 days after receiving the specific request from him. Network Transmission System Data shall be issued within 2 months following the user's request, depending on the nature and complexity of the data required.

Article 25. OST sh.a right for data and information reservation

1. OST shall be entitled to keep confidential any network Transmission System data, whether the reasoned opinion by OST, the issuance or publication of such information shall seriously affect the interest of the business activity of OST sh.a. However OST shall provide a minimum data sets, without which it is clear that users can not undertake their business activities without these data.
2. Up to date where Connection Agreement between OST and the Grid User enters into force, data and information received shall be treated as confidential and will not be exposed to third Parties.

Article 26. Planning for improvement and modification of system equipment

1. Planning to improve existing power system behavior and equipment/installations of it involves modification and/or total replacement of equipment/installations by performing a series of works, but without interfering to the main device.
2. The objectives of such Plans that include small investments, are: improving the behavior of equipment, the quality and level of security of supply, static and dynamic stability of the network, operational system security, economic criterion, reducting of losses and improveing of network service indicators, improving the standards of human life and equipment safety and environmental improvement.
3. All Parties in cooperation with the OST, shall identify areas where modification works will be carried out by making investments, which will improve the quality and/or quantity of benefits and shall develop plans for quality improvements and contemporary behavioral of their systems/ facilities.
4. OST shall develop programs to improve Transmission System operational regime. Relevant interventions, in areas where such improvements are planned shall be defined by OST occasionally.

Article 27. Deadlines for 2-year plans for renovation&modification of Transmission Network Users

1. Deadlines for 2-year plans for renovation&modification of Transmission Network Users shall be submitted in OST sh.a until 30 September, of each year, for two subsequent years.
2. Implementation of modifications and renovations may be extended by mutual agreement of the Parties. A Party may request extension for technical or other inherent difficulties. If no agreement is reached between the Parties for program plan of modifications & renovation, the issue shall is resolved by the Dispute Settlement Procedures described in the relevant provisions of this Transmission Network Code..

CHAPTER III

CONNECTION CODE

Article 28. Subject matter and Scope

1. Connection Code defines the norms(standards, conditions, criterions, techinhal requirements, rules) and time horizons in non-discriminory bases, to be meet by Grid Users during the application phase, for a new connection with Transmission Network or modyfing their existing connections with the network.
2. Connection Code defines minimum technical specifications required by the Parties, performance standards and operational criteria in the connection point, to ensure user's system and Transmission System protection, in general by guaranteeing the design, control, and secure, sustainable operation .
3. Connection with Transmission System Network is regulated by Connection Agreement between OST and concerned Party for each connection point in particular, by clearly defining the technical functions, operational criteria and related ownership of equipment

connected to transmission network in accordance with the division of relevant responsibilities and ownership;

4. Connection Code shall be applied to all entities that apply for connection and use, to the Transmission Network, including existing Users who ask to make changes to their systems or related facilities.

Article 29. Connection application procedures (new and / or modification)

1. Any entity that requires to be connected with Transmission System Network, or any existing Grid User that asks to modify an existing Connection and Agreement of Transmission Network usage, shall apply the requirements and procedures set forth herein.
2. Entities, according to paragraph (1), shall submit the Application for Connection to OST.sh.a, according to relevant application forms for the new connection, or modification of the existing connection, to the transmission network, designed and published by OST, pursuant to " Rules of Procedures for New Connections and Modification of Existing Connections to the Transmission Network ", in accordance with Article 27 of law No.43/2015 "On Power Sector ".
3. Any application for new connection, or modification of the existing connection, will be subject to the relevant tariffs, procedures and time limits, specified in accordance with the requirements of Article 27, 28 and 29 of Law No.43 / 2015 "On Power Sector" .

Article 30. General technical documents for Connection application

1. The Applicant submits regarding Connection,to the OST, the information as follows:
   a) Identification data and economic activity/legal (name of company, legal representative, address, phone, fax, e-mail, web, etc.).
   b) Data of network user, System / Object to be connected (power generating unit, system/facilities of Distribution System Operator, system/facility, clients/different customers) including data coordinates on the map of mains Transmission System, for connection / location of connection.
   c) A written statement on its willingness to implement correctly the provisions of the Transmission Network Code.
   d) Connection Study of the Generation Units / Distribution System Operator / Client / Customer and standard planning data by the Planning Code;
   e) Data for installations and equipment that generate / absorb reactive power;
   f) The data for respective phases, according to technical and economic studies of the User, for the realization of the investment project indicators (time horizons: technical design stages, stages of implementation, commissioning-testing, commissioning / receipt and energization).
   g) A list of general and technical documentation attached, to the application form, for New Connection or modification of the existing Connection.

Article 31. Data and information exchange

1. Any new or existing Grid User, that requires to change his Apparent Power,or primary scheme of connection with transmission network, after planning studies published by OST, can require by OST sh.a more information or data.
2. OST shall provide the required data, against reasonable fees, within 30 days, after the date of the formal request, according to procedures provided in this Code.
3. OST may refuse to provide data or information, whether its case considers them confidential /or unnecessary for performing of legal user’s activity, that requires these data.
4. The exchange of data and information between the OST and Transmission Network Users must be in compliance with the provisions of the Network Transmission Code – Planning Code.

5. For the purposes of the study of "Acceptability of new connections or modifying of existing connection" in transmission system, Applicant shall submit Standard Planning Data, according to tables of Annex A-categories and planning data.

Article 32. Optimal Connection Point/Interface

1. OST shall approve any point/interface which technically is optimal, where Transmission Network Users can connect systems / objects with this system.
   a) Generators/Producers Connection points will be Transmission Network per rated voltage 110 kV, 220 kV, 400 kV;
   b) Distribution System Operator Connection Points will be Transmission Network, per rated voltage to 110 kV;
   c) Client/Cunsomers connection points ,will be in Transmission Network with rated voltage 110 kV and 220 kV.
2. If after studying of "Acceptability of the new Connection or Modification", results that the new connection must be made in Distribution System Network, in < 110 kV voltage, then the request for application return officially back to applicants.

Article 33. The process and application phases

1. Application for a new connection, or modification of the existing connection to transmission network starts with the formal submittion to OST sh.a of the application format, specified in the "Rules of Procedures for New Connections and Modification of Existing Connections to Transmission Network" and must be attached with the described documentation detaled in Transmission Network Code / Connection Code.
2. The applicant completes the application refering to the standard planning data, according to tables of Annex A - "Categories and planning data", of Transmission Network Code.. When it is necessary from the technical viewpoint, OST sh.a may establish additional criteria/technical requirements, to those defined in the Transmission Network Code., but in all cases it will inform the other Pary within the limits defined in this Regulation and Connection Code.
3. After application recived, OST sh.a carry out the study of "Acceptability of a new connection or modifying of the existing connection" with transmission system network. OST assess whether the documents and information submitted by the applicant are complete and in accordance with the requirements of this regulation. OST communicates to applicant its response to accept or reject the application within 60 calendar days from the date of submission of application.
4. In cases where the application has a lack on any of the documents or information provided in this regulation or if OST requires additional data or information from the applicant in accordance with paragraph 2, the applicant is required to submit the required documentation,within 30 calendar days from the date of notice, of its completion. In this case the term of Accession or rejection of the application according to the paragraph 3, be 90 calendar days from the date of filing the application.
5. If the applicant does not submit the required documentation within the period specified in paragraph 4 of this Article, the TSO rejects the application.

Article 34. New Connection Offer and/or modification of the existing connection

1. After submission of all information required by OST sh.a, the latter based on the study of "Acceptability of a new connection or modification of existing connection", within the time limit set out in paragraph 4 of Article 33 shall:

a. submit to applicant, Connection Offer defining point / interface or solution that is technically optimal and coordinate the network requirements submitted by other applicants for connection with Transmission Network; or
b. if after studying of the "Acceptability of new connections or modification of existing connection" results that the optimal solution would be the connection on medium voltage network, the request for application of the applicant, officially turnes back with this argument; or
c. in case of a negative response, notify the applicant for the rejection of the application, justifying the reasons for this decision.

2. The applicant within 60 calendar days after receiving of the offer for Connection, must officially inform OST sh.a, for its acceptance or not by the Declaration of Acceptance. If the Connection Offer according the letter (a) above, will not be accepted by the applicant, or the applicant does not inform OST sh.a within the time specified, the application of connection process resumes from the start.
3. If the applicant accepts the Connection Offer, the validity period of the connectivity offer is 18 months from the receipt of Connection Offer by Applicant. In the application, submitted to OST sh.a, the network user must have shown the period of construction of the facility and its energisation.
4. After acceptance of the Connection Offer, by Applicant, pursuant to study "Acceptability of new connections or modification of existing connection" carryed out, OST sh.a must verify, review and evaluate all the application according to requirements of Transmission Network Code / Connection Code as below but not limited to:
   a) the application data and technical documentation of connectivity and minuted;
   b) the possibility for the use of Transmission System network capacity and if there is no possibility, the Applicant shall take technical measures and shall invest itself to full coverage of the investment within technical security conditions, specified in Transmission Network Code and law No.43 / 2015 "On Power sector".
   c) defining and selection of the New Connection location, in the right place, according to the security level of supply, static and dynamic stability, magnitudes of short circuits 3 and 1 phase, the impact on technical losses in transmission network with new connection and the power supply of own needs, especially in cases of generating units connection;
   d) connection applicant's costs, in accordance with Article 27 and 28 of Law No.43 / 2015 "On Power Sector", and "Rules of Procedures for New Connections and modification of existing connections to Transmission Network ",according the Offer Connection consulted and accepted by the Applicant;
   e) the fulfillment of all conditions and technical standards of Connection Point and Technical Connection;
   f) the correct implementation of Transmission Code provisions.
5. The Applicant, within 16 months after receiving the connection Offer by TSO sh.a, submits the request to proceed with Connection Agreement type, as defined in "Rules of Procedures for New Connections and Modification of Existing Connection in Transmission Network ".
6. OST sh.a and the Applicant shall sign the Connection Agreement, jointly with annexes, within 18 months after the receiving of Connection Offer, taking into account the conditions and technical requirements.

Article 35. Technical requirements and conditions for new connection or modification equipment

1. All plants and equipment at the connection point will be in accordance with relevant Albanian standards, or in their absence with international standards, in accordance with applicable

legislation, guaranteeing the continuity of cooperation with other network users, and operation and high technical quality maintaining of their system/object according the provisions of this Code and the European Grid ENTSO-E.

2. New connections and / or modifications of existing ones should not cause any negative effect on the existing transmission network users and vice versa.
3. The technical requirements for equipment and Connection Points with Transmission Network are:
   a) equipment, facilities, installations and technical conditions in Connection Points shall be in conformity with the norms, national standards and standards of ENTSO-E, the same for all users and according to the relevant categories of them.
   b) Connections between network users and Transmission System Network should be realized via power switches, capable to be disconnected, with fast action according the requirements and standards in power systems.
   c) selection and define of the switching and commuting equipment capabilities, and sustainability against short circuit currents, must be within the values and standards in force, defined for each connection point.
   d) protections installations relays, in the of connection points between Transmission System Network and Network Users must meet clearly the requirements and technical standards in force, to reduce to technical minimum, negative impact on other Transmission System Network Users.
   e) telecommunications equipment at connection points between the Transmission System Network and Network Users must clearly meet the technical requirements and standards of the Transmission System Network to eliminate the negative impact in transmission system.
   f) equipment that enable, Transmission Network Users monitoring and control, must meet the technical requirements of the Transmission Network, in order to standardize and to be adapted with the logic of SCADA / EMS.

Article 36. Connection Agreement

1. If the Applicant request for Connection is accepted,and the latter accepts the connection offer, considering the conditions and technical requirements, TSO sh.a and the Applicant / User of the Transmission Network, proceed with the signing of the Connection Agreement as defined in " Rules of Procedures for New Connections and Modification of Existing Connections to the Transmission Network ".
2. Agreement imposes an obligation on the Parties to implement the rules, procedures, technical specifications and requirements for equipment and installations, as provided in this Code, according to specific provisions in the relevant Connection Agreement.
3. Connection Agreement among other things specifies the general connection conditions and any specific technical and financial condition applied to each connection.
4. Attached to Connection Agreement shall be the documentation (including an electronic copy) which the applicant submits to OST, together with Connection Offer acceptance, as follows:
   a) general layout line mapping, the track and its layout in A3 drawing formats;and
   b) mains Plant Scheme, step up substation and HV network connection (single line diagram);and
   c) the principal relay protection scheme and measurements (including transformer,the HV, HV/ MV;and
   d) telecommunications diagram and SCADA connection with NDC;and
   e) relay protection diagram;and
   f) control monitoring diagram;and

g) technical specifications of main equipment (HV part and the tranformer HV/MV);and
h) the default form with data for HEC, TEC, WEC, PVEC etc;and
i) the default form with data of transmission line;and
j) the default form with data for step upsubstation MV/HV;and
k) layout of step up substation MV/HV;and
l) general layout mapping,and Connection Point to Transmission Network;and
m) statement of Readiness to respect the requirements of the Grid Code;and
n) the Declaration on the responsibilities for equipment control and maintenance, equipment operation and responsibilities for technical safety of staff;and
o) bank document which confirms the payment of connection fees.

Article 37. Formulation of Technical Connection Permission granted by OST

1. In accordance with the Transmission Network Code /Connection Code, "Rules of Procedures for New Connections and Modification of Existing Connections to the Transmission Network" and relevant connection agreement, according to details and deadlines required in the agreement, the Applicant is required to submit a periodic report and a final certificate of performance of its infrastructure, connection with transmission network, explaining performance in quantity and quality terms, of technical and operational criterions, specified in the Transmission Network Code, as well as additional requirements provided by law, bilateral agreements and / or as required by TSO .
2. The operational procedure notification for any user is performed in accordance with the relevant provisions and detailed as follows:
   a) Energisation Operational Notification (EON);
   b) Interim Operational Notification (ION);and
   c) Final Operational Notification (FON)
   d) Limited Operational Notification (LON).
3. User shall provide all assistance and information necessary for TSO sh.a, to collect data to verify the fulfillment of technical requirements and performance.
4. It is recommended for the user, to consult and check with OST sh.a relevant issues in an early stage of the project, in order to enable the necessary corrections before project implementation, connection / modification and full compliance verification, for the purpose of final connection commissioning and energisation.
5. The relevant commissioning Group, of the New Connection or Modification of Existing Connection, drafts Connectivity Technical Permission of the New Connection or Modification which contains the entirety of technical documentation as follows:
   a) general terms and conditions for the main technical indicators, for new network elements which start operation and use;and
   b) the specific technical conditions of Connection, if any;and
   c) compliance with the provisions of Transmission Network Code; and
   d) compliance with the requirements for monitoring and controlling, measuring and telemetry, local SCADA, interface with SCADA / EMS of Transmission System and telecommunications systems;
   e) obligations of applicants to participate in Defense Plan and Restoration Plan
   f) meeting the requirements and standards relating to the protection relay, automation and its coordination with existing protection of Transmission System Network;
   g) annual parameters for power Supply / Consumption;

h) operational and technical conditions according to which the Grid User shall be de-energized or disconnected from Transmission System Network;
i) completing the requirements regarding standards to be met by connection equipment at the connection point.

6. The document of Technical Connection Permission shall be issued after the signing of the "Connection Agreement" between the OST sh.a and the Applicant as Transmission System Network User.
7. "Connection Agreement" is a document component of Technical Connection Permission.

Article 38. Nominal voltage levels and its allowed values

1. Nominal voltage levels permitted, maximum and minimum values are detailed as follow, in accordance with the Chapter V of this Code. These values are permitted for normal network operation of Transmission System and after a contingency listed in Transmission System Network analysis.

Nominal Voltage Level (kV)	Max Voltage range kV(p.u)	Min Voltage range kV (p.u)
400 kV	420 kV (1.05)	360 kV (0.9)
220 kV	245 kV (1.118)	198 kV (0.9)
150 kV	168 kV (1.118)	135 kV (0.9)
110 kV	123 kV (1.118)	99 kV (0.9)

2. Any new connection of DC installations, HVDC, must be designed in the manner that, do not create negative effects (sub-synchronous resonance, rapid voltage variations, voltage harmonics and interference with telecommunications), in the existing devices connected with network, or adverse effects (incapability of reducing the voltage or surplus of reactive power input / output) in function / operation of the Transmission System network.
3. A bipolar installation HVDC should also be designed so that the risk of loss to both poles, for the same reason, to be as low as possible.

Article 39. Voltage imbalances

1. Voltage Imbalance is defined as:
   a) phase voltage amplitudes difference
   b) angles between phases from 120^{o} difference.
2. Phase voltages should have equal and out-phased amplitude of 120 o. Any deviation causes malfunctioning of rotating machines, efficiency decrease, vibrations, overheating, etc.
3. Imbalance voltage amplitude and phase limits are:
   a) per networks at nominal voltage level 400 kV and 220 kV:2%
   b) per networks at nominal voltage level 154 kV and 110kV:3%

Article 40. Deformation from Harmonics

1. For nominal voltages of 110 kV - 400 kV of Transmission System Network , total harmonic distortion should be not more than 2%;
2. Grid Users should take appropriate measures to limit and minimize the harmonics.

3. In normal operating conditions and planning of Transmission System Network outages, the maximum negative sequence component of phase to phase voltage of Transmission System network should not exceed 1% for 99.5% of the time.

Article 41. System Frequency

1. Nominal power system frequency synchronously with European Transmission Network ENTSO-E is 50 Hz ± 0.05 Hz and will be held within the allowed range as detailed in frequency standards of Chapter VI of this Code.
2. Installations of Transmission Network User (Generation or Clients) must meet the standards of frequency and its regulation.

Article 42. Voltage Flickers

1. If the voltage fluctuations triggered by Clients, such as electric arc furnaces, compressors, powerful asynchronous motors, welding facilities, etc., affects the other Grid Users, OST sh.a shall check and monitor this phenomenon in 110 kV and 220 kV busbars voltage.
2. Fluctuation limits, control and measurement procedures will be based on the relevant IEC standards.

Article 43. Power Factor (cosφ)

1. Demand / Clients of Transmission System network should have a power factor (cosφ) as close as 1 unit (≥ 0.9);
2. The minimum permissible power factor of OSHE and Clients is 0.9 (cosφ = 0.9)
3. Measurement of power factor shall be carried out continuously along with the voltage measurement in real time, via the SCADA / EMS system and telemetry.
4. OSHE and Clients/Demand with power factor lower than the allowed value, should immediately install reactive power compensating devices (battery condensers) for improving cosφ.

Article 44. Relay Protection Requirements and Coordination with Transmission Network User Relay Protection

1. Installations and equipment of Transmission Network Users will not be connected or remain connected with Transmission System network, if they are not equipped with necessary relay protection which fulfills the relevant security principles such as selectivity, speed, differentiation and sensitivity.
2. In addition to these principles and to increase the performance, protection relays installed in Transmission System network should coordinate its actions on a permanent basis, in cooperation with the relay protection installed on the Transmission Network user's installations and equipment. For this purpose, OST and Transmission Network Users interact at any time in the settings of relay protection and improvement of relay protection technology. Relay protection network of systems / facilities of Transmission network Users should not be set and put into operation without regular consulting, at any time, and officially with OST Company.
3. Any uncertainties, problem and dispute over the setting and coordination of Relay Protection of Transmission System network and Network Users shall be evaluated and settled in bilateral meetings, initiated by either party.
4. OST shall be responsible for setting of relay protection throughout the Transmission System Network 400 kV, 220 kV, 150 kV, and 110 kV. OST approves relay protection system and set the settings to network elements in coordination with Transmission network Users. Transmission network Users by them, are responsible for settings of Relay Protection of their network, systems / objects and shall coordinate the settings of Relay Protection in these installations and equipment on the property boundary with Transmission System Network.

5. Distribution System Operator shall prepare studies and plans for modifying protection systems and automatics, for installation of frequency relays in cooperation with OST sh.a Company. OST sh.a can advise modifications and improvements to the distribution system network, as a special maintenance and replacements of weak parts, in order to reduce disconnection from frequent faults in this network and consequently their impact on Transmission System network.

Article 45. Minimal Time Setting of Relay Protection

1. After planned studying and analyzing of Dynamic and Static Stability Assessment (stability side voltage collapse, angular stability, stability side frequency) performed by OST and in continuous cooperation with transmission Network Users, as well as performance analysis of relay protection, the primary switching devices installed in Transmission System network, OST shall determine the minimum critical disconnection time of fault (critical cleaning time fault in the power system). The minimum disconnection critical time is submitted in the table below.
2. The Transmission Network Users shall be notified immediately, whenever value changes have to be made.

Voltage level, kV	Total Time of Relay Protection Functioning plus the Time of circuit breaker
400 kV	80 mlsek
220 kV	110 mlsek
150 kV, 110 kV	120 mlsek

Article 46. Requirements on Generator Relay Protection

1. All Power generating units, connected to Transmission System shall be protected by a relay protection system, in accordance with relevant standards, hence Transmission System Network does need to cope any disturbance or fault from a failure originated by Power Generating units.
2. Relay protections installed in Power Generating Units and Block Transformer- Power Generating Units shall include:
   a) Differential Block Protection
   b) Differential Generator Protection
   c) Maximal Protection with Minimal Voltage Blocking
   d) Overlfluxin Protection
   e) Protection from Asymmetric and Symmetric Short Circuits
   f) Protection from Earthing in Stator
   g) Protection from Earthing in Rotator
   h) Overvoltage Protection
   i) Loss of Excitation Protection
   j) Neuter Protection of the Block
   k) Reverse Order Protection of transformer-power generating unit
3. Transformers Generation in itself added:
   a) Maximal Protection with/without Minimal Voltage Blocking
   b) Neuter Protection
   c) internal transformer failures protection

4. Settings of Transformers and Generators connected in block (generator-transformer) shall be set in block.
5. Auxiliary Power Generating Units Transformers shall be equipped with :
   a) Maximal Protection with/without Minimal Voltage Blocking
   b) Neuter Protection
   c) Internal transformer failures protection

Article 47. Relay Protection Requirements of Transmission System Network

1. Lines of high voltage 400 kV, 220 kV, 150 kV, and 110 kV shall have Distant and Back-Up Protection. All lines 400 kV, 220 kV shall have two main distant protections; Distant fast operation and backup distant protection
2. It is preferable that the main protections to be fed from different voltage and current sources.
3. Based on specific performance analysis of relay protection, network Transmission System can provide additional backup protection, in certain power lines.
4. All compensating equipment connected to Transmission System Network should be equipped with protection relay according to the relevant standard.
5. Other technical specifications for electrical lines 400 kV, 220 kV, 150 kV and 110 kV are:
   a) Distant Protection of electrical lines, in 400 kV, 220 kV, 150 kV and 110 kV can be static or numeric with at least 4 fast-acting areas;
   b) Main protection 1 and 2 on the electrical lines of 400 kV, 220 kV, have the same action velocity and preferably with different principles of operation;
   c) Time setting of zones should include switchers' action times
   d) Action timing of the first zone (together with the switcher's action) is 80 mil.sec per 400 kV lines, 110 mil.sec per 220 kV lines and 120 mil.sec per 150 kV and 110 kV lines.
   e) Timing of other zones is defined according to Transmission System covering zone and configuration calculated for any year. Protection 400 kV and 220 kV lines is equipped with the single phase Auto Reclosing Device , and triple phase Auto Reclosing Device (AKP) for 150 kV and 110 kV lines, with the control of voltage lack and synchronization at both ends of the power line.
   f) Subject to operational security analyzes of power system by OST sh.a, the main relay protections 1 and 2 may have DC supply (operating direct current) from different accumulator batteries installations.
6. Relay Protection requirements for Auto and Power Transformers in the power system includes Differential Protection and other protections (technological) from internal impairment (as gaseous Protection, Winding Temperature Protection, Oil Temperature Protection and Fire Protection).

Article 48. Earthing

1. To increase the efficiency and selectivity and the whole Relay Protection performance of Transmission System Network, grounding of the primary side windings, of the power transformer at voltage levels 400 kV / MV kV, 220 kV / MV substations, 150 / TM kV, 110 / TM kV ,has a special importance. Earthing system shall be studied, analyzed and established by OST sh.a. Earthing status and size of earthing resistance defined by relevant studies of OST is obligatory to be respected by all Users of the Transmission System Network, their systems / objects.

Article 49. Requirements on relay protection in 35-20 kV voltage lines

1. Lines of medium voltage 35 kV, 20 kV, 10 kV are protected by Maximal Current Protection, Instant Protection and Protection of Defects directed to the Earth. Setting of Relay Protection

in Distribution System in medium voltage lines or Clients/Customers shall be determined by these Transmission Network User in collaboration with OST sh.a.

2. Systems / facilities of OSHE network and clients / customers of the Transmission System network, power transformers in electrical substations shall be equipped with Differential Protection, Maximum Directed Current Protection and Relay Protection for earth defects

Article 50. Requirements on Substations Busbars Protection

1. Substations busbars of 400 kV, 220 kV, 150 kV, 110 kV voltage level, are protected by Differential protection. Busbars are also equipped with Protection from Switcher Action Refusal.

Article 51. Fire Protection of electrical installations and equipment

Fire Protection System for electrical installations and equipment and its implementing rules should be in accordance with specifications, standards, regulations and legal provisions in force on Fire Protection.

Article 52. Data Protection Relay of Transmission Network Users

1. Data protection relay required by OST sh.a,by network of Transmission System network users are as follows:
    a) types, specifications and settings of all relays and relay protection systems installed to power generating units, generator-transformer block, step up substation transformers, Ancillary transformers, and main Ancillary equipment.
    b) types, specifications and settings of all relay, installed in all power transformers substations of Distribution System and Clients of transmission network 220 / HV kV and 110 kV / MV.
    c) types, specifications and setting of relay protection installed on all busbars 110 kV, 150 kV, 220 kV, 400 kV and 35-400 kV lines owned by the transmission network users.
    d) The data required for determining the short circuits currents, at any connection point regarding new or existing transmission network users, based on its planning-developing and its commuting equipment capabilities in technical ranges and ownership of their network with transmission System.

Article 53. Requirements on connection of new generation modules to network

1. Minimum capacity threshold from which a power generation module will be connected to transmission system network is 15 MW for 110 kV voltage level at the connection point and 50 MW for 220 kV voltage level at the connection point with Transmission System.
2. A power generating module should be capable to remain connected to the system for specified frequency and voltage ranges as follows:

Frequency ranges	Time period for operation
47.5 Hz – 48.5 Hz	not less than 30 minutes
48.5 Hz – 49.0 Hz	not less than 50 minutes
49.0 Hz – 51.0 Hz	unlimited
51 Hz – 51.5 Hz	not less than 30 minutes

3. New power Generating Units shall apply correctly the provisions of this Code.
4. Power generating modules of type "with connection point to distribution and / or transmission system network" should be capable to supply nominal active power output with a power factor value from 0.85 inductive to 0.95 capacitive.
5. All power generating units should be capable to normal operation in all points of the capability curve.
6. The Short Circuit Coefficient (Kc) of a power generation units should not be lower than 0.5.
7. Power Generating Units should be capable to supply nominal active power to transmission system network even when the power system frequency is within the limits from 49.5 Hz to 50.5 Hz. All power generating units connected to the transmission system must be capable to supply active power, depending on the frequency changes in the system.
8. Power generating modules should have Automatic Voltage Regulator AVR and Automatic Governor Regulator. The droop settings shall be between 2% and 12%.
9. Power generation Units should have connected the star of stator winding ready for earthing. The star earthing point in these units is determined by studies and analyzes made on overvoltages and network dimensioning equipment of Transmission System, which determine the earth connection factor.The earth connection Factor should be 1.4 or lower. Power Generating modules should implement without delay the instruction given by TSO sh.a on star earthing point status, whenever this status changes.
10. Hydro Power Generating Units should be capable to continue their stable operation for any load between 35% and 105% of nominal active power capacity.
11. Any Power Generating Modules should equipped with Supervisory Control and Data Acquisition (SCADA) and telemetry. The power generating module shall provide to OST sh.a, through SCADA installed in its system/object, the required functioning parameters pursuant to the provisions of the Transmission Network Code and the Connection Agreement.
12. Each power generating unit should have at least the following capabilities:
        a) To generate active power and operate to normal parameters for system frequency within the ranges 49.5 Hz - 50.5 Hz.
        b) To remain synchronized with the network within System frequency in ranges between 47.5 Hz – 49.5 Hz and 50.5 Hz – 52.5 Hz for 60 minutes
    a) To remain synchronized with the network within the System frequency ranges between 47.0 Hz – 47.5 Hz per 20 seconds. This is required any time the frequency is lower than 47.5 Hz.
    b) To remain synchronized with the network within the System frequency ranges between 52.5 Hz – 53 Hz per 5 seconds. This is required any time the frequency is more than 52.5-53 Hz.
    c) To remain synchronized with the network within the System frequency changes more or equal to 0.5 Hz/sec.
    d) to continue operation for minimum active power capacity generation, according to the technical passport of the generating unit, within frequency ranges between 49.8 Hz - 51.0 Hz.
    e) To remain synchronized with the network during voltage deviations, in the connection point in the ranges between 0.85 p.u-0.90 p.u for 60 min and for 1.118 p.u – 1.15 p.u at least for 20min.

f) To continue operation in accordance with capability curve specified by the technical passport of the power generating unit, for any case required to maintain voltage levels, in accordance with the provisions of Transmission Network Code.
g) To remain synchronized during imbalances between generation/load according to IEC 60034 - 1 standards
h) The capability to increase / decrease output: not less than 1.5% of nominal active power / minute, when the power generating unit is in normal operating conditions.
i) The total capacity of power generating units without regulation (of frequency and voltage) connected to transmission network system should not be greater than 5% of annual peak load of the system.
j) The requirement on min. and max size output is excluded for power generating units without regulation,.

13. Any existing power generating units (old technology) should minimally be capable to provide active power for power factor cosφ on the ranges +0.85 injection to -0.95 absorption.
14. All generating unit (the new technologies) should be capable to provide nominal active power for cos φ power factor, at ranges +0.9 injection to -0.95 absorption, in accordance with the reactive power capability curve.
15. For all cases, of the equipment and new technologies implementation, in the field of electricity generation, especially in energy production from renewable sources, which are not provided in this Transmission Network Code, the OST will address relevant issues and problems in ERE, for its discussion and approval of each case.
16. OST forces certain Power Generation owners (Producers) to install power system stabilizer (PSS), after detailed studies it performs. The cost of these installations / modifications shall be afforded by Power Generating Owners, on the basis of a reasoned request by OST sh.a Company, for increasing the level of security and quality supply and service of Transmission System Network.
17. The requirement for PSS shall be specified in the Connection Agreement.

Article 54. Requirements for Telecommunications and SCADA / EMS System.

1. Transmission Network User's Plants and electrical equipment shall not be connected, or remain connected to the Transmission System Network, if they are not equipped with telecommunication installations and interface for connection to SCADA / EMS of OST sh.a., accomplishing the necessary requirements on Operational Security, and normal operation of the Transmission System network.
2. In addition to these necessary technical conditions, telecommunication equipment and system interfaces with SCADA / EMS of OST sh.a, connected with Transmission System network should be parameterized in order to be compatible with the telecommunication network and SCADA / EMS system of OST.
3. Telecommunication equipment and network interface with SCADA /EMS of OST sh.a, of Transmission Network Users should not parameterized and set in operation without regularly consultation, at any time and formally with OST.
4. OST will be responsible for checking the parameterization and operation of telecommunication equipment and network interface with SCADA / EMS of OST.
5. OST approves telecommunication equipment and interface with SCADA / EMS of OST that User will install. Also sets the parameters and technical details in accordance with the location and condition of connection to the network transmission system.

6. Transmission System Network Users are responsible for parameterizing of telecommunication equipment on both interface's sides and their integration in OST's telecommunications network.
7. The transmission system Users are responsible for parameterizing the system interfaces with SCADA / EMS of OST, on both interfaces sides.

Article 55. Telecommunication Requirements of Transmission System Network.

1. Telecommunications lines between User's facility and the OST's telecommunication network to substations where they will be connected, shall have an interface and equipment integration and communication functions with existing telecommunications network of OST.
2. Connection with telecommunication network of OST should be redundant, except cases when the User is a small capacity power generating module, the impact of it on the Transmission System network is not detrimental to the normal operation, and the connection with OST's network telecommunication is impossible, due to connection location with Transmission System network.
3. Equipment that user should install in its facility and in substations where it will be connected and have an interface with the OST's telecommunication network, must be compatible with the telecommunications network equipment of OST, and in accordance with the requirements and its standards. They should be similar in architecture and operation with OST's network telecommunication equipment, in order to maintain standardization and performance of OST's telecommunication network.
4. In cases when the high-voltage line possesses OPGW, so users can connect via optic fiber with OST's telecommunication network, the User should supply and install OPGW to fulfill the communication functions with OST. OPGW installation will be done according to the specifications that fit with that part of the network.
5. The user must install telecommunications multiplexer equipment for connecting with optical fibers, supply 48 VDC (DC) by an accumulator battery installations, telephone equipment,Teleprotection and data communication equipment (DATA) to perform such communication functions with OST. Installation of equipment will be done according to the specifications that fit with that part of the network.
6. In cases when the high-voltage line do not possesses OPGW, and so the User cannot be connected via optic fiber with OST's sh.a telecommunication network, then the User must supply and install high-frequency Power Line Carrier telecommunication equipment, primary relevant equipment, supply 48 VDC (DC) by a battery accumulator installations, telephone equipment, accessories of teleprotection and communication equipment data (DATA) to perform the communication functions with OST.
   Installation of equipment will be done according to the specifications that fit with that part of the network.
7. The transmission system network User, before installing the equipment must submit for approval to the OST 's:
   a. The design and connection scheme with telecommunication network of OST.
   b. The specifications of equipment which will install and their documentation.
8. User Connection with transmission system network will be depending on the electrical connection scheme that is provided. This is due to the impact on the existing telecommunication network.

Article 56. Requirements on SCADA / EMS System related Transmission System Network

1. The User must install equipment (control systems) to collect data on objects, and if necessary in substations where it will be connected and these equipment should have an interface with the SCADA / EMS system of OST. The User should integrate and implement the interface of SCADA / EMS system with local control system of the substation where it will be connected, (if any).
2. Equipment that user should install in its facility and in substations where it will be connected and have an interface with the OST’s telecommunication network, must be compatible with the telecommunications network equipment of OST, and in accordance with the requirements and its standards. They should be similar in architecture and operation with OST’s network telecommunication equipment, in order to maintain standardization and performance of OST’s telecommunication network.
3. Transmission System Network User, prior interface implementation with SCADA / EMS system, must submit for approval to the OST, the request regarding connection with SCADA / EMS system, where attaching to this request must submit substation single line diagram, the list of data available to monitor and SCADA Scheme system connectivity.

CHAPTER IV

Network Code Network Code on Operational Planning and Scheduling

Article 57. Subject matter and scope

1. This Network Code Network on Operational Planning and Scheduling defines the minimum Operational Planning and Scheduling requirements for ensuring coherent and coordinated operational planning processes of the Transmission System and to support the coordination of operation in the European synchronous area.
2. The Code also supports the development of methodologies of system operation to facilitate the expected enhancing of RES generation, connected to the system.
3. OST and all users must comply with the requirements necessary to establish conditions for the operation of the system in real time and to develop appropriate necessary measures to maintain operational security, quality and stability of interconnected system and support the efficient operation of the electricity market.
4. This Network Code aims at:
   a) determining common time horizons, methodologies and principles allowing to carry out coordinated Operational Security Analysis and Adequacy analysis to maintain Operational Security and support the efficient functioning of the European internal electricity market; and
   b) determining conditions to coordinate Availability Plans, allowing works required by Relevant Assets.

   For the purpose of this Network Code, Existing Power Generating Modules shall be classified as type "with connection point to transmission network" and type "with a connection point to distribution network". For the purpose of this Network Code, Existing Demand Facilities shall be classified according to the criteria defined by ENTSE. The Significant Grid Users within the scope of this Network Operation Code are defined to article 108(5) point (a) (b) (c) and D)

Article 58. Individual and Common Grid Model general provisions

1. OST shall establish Individual Grid Models for merging into Common Grid Models consistent with the objectives of this Network Code for each of the following timeframes:

   a) Year-Ahead, in accordance with Article 60 and Article 62;

   b) Where relevant, Week-Ahead, in accordance with Article 63;

   c) D-1, in accordance with Article 64; and

   d) Intraday, where applicable in line with Article 67(3) (c).

2. When OST establishes an Individual Grid Model for a timeframe consistent with this Network Code, OST sh.a shall ensure that the Individual Grid Model is in line with the requirements established in this document.
3. Individual Grid Models described in Article 60(1) shall include the data described in Article 118(3), as well as thermal limits of elements of the Transmission System.
4. The European Merging Function shall establish Common Grid Models consistent with the objectives of this Network Code based on:
   a) Scenarios or forecasts provided in accordance with Article 59, Article 64 and when relevant Article 63;
   b) Individual Grid Models developed in accordance with Article 60, 62, 64 and and when relevant Article 63; and
   c) The provisions agreed upon in accordance with Article 61(1) and Article 64(1).

Article 59. Year-ahead scenarios

1. According to ENTSO-E rules, each year, OST shall establish a common list of scenarios against which the operation of the interconnected system shall be assessed by OST. These scenarios shall allow the identification and the assessment of the influence on the Operational Security of the interconnected Transmission System. These scenarios shall include the following variables:
   a) demand ;
   b) conditions related to the contribution of Renewable Energy Sources ;
   c) defined import/export positions, including agreed reference values allowing the merging task; and
   d) Generation pattern given, considering a fully available production park.
2. These scenarios shall be established considering the following:
   a) typical cross-border exchange patterns for different levels of consumption and of Renewable Energy Sources and conventional Generation;
   b) the probability of occurrence of the scenarios;
   c) the potential for possible deviations from Operational Security Limits associated with each scenario;
   d) the amount of power generated and consumed by the Power Generating Facilities and Demand Facilities connected to Distribution Networks.

Article 60. Year Ahead Individual Grid Models

1. In accordance with the provisions defined pursuant to Article 61(1), OST shall establish a Year-Ahead Individual Grid Model for each of the scenarios defined in accordance with Article 59, using its best estimates for the variables defined in Article 59(1), and make it available through the ENTSO-E Operational Planning Data Environment.
2. When developing Individual Grid Models in accordance with Article 60(1), OST shall:
   a. agree upon the estimated power flow on DC interconnections with the directly connected TSOs; and
   b. balance the sum of the following for each scenario:
      i. net exchanges on AC Interconnections;
      ii. estimated power flows on DC Interconnections;
      iii. demand, including an estimation of losses; and
      iv. Generation.

3. When developing Individual Grid Models referred to in Article 60(1), OST sh.ashall ensure that the aggregated power outputs for Power Generating Facilities connected to Distribution Networks are:
    a) consistent with the structural data provided pursuant to the requirements of Article 120,122,125 and 128 of this Code,
    b) consistent with the scenarios defined in Article 59; and
    c) differentiated according to the type of primary energy source.

Article 61. Year ahead common grid models

1. OST shall implement the provisions dealing with the gathering of the Year-Ahead Individual Grid Models referred to this point of Article, merging them into Common Grid Models and saving them. These provisions shall cover the following elements:
    a) data format;
    b) a procedure to handle modifications to the Network Topology or operational agreements;
    c) deadlines for the gathering, merging and saving of the year-ahead Individual Grid Models into Common Grid Models;
    d) quality control of datasets;
    e) a procedure for model improvement;
    f) tasks to be performed at the regional, Synchronous Area level; and
    g) requirements for the ENTSO-E Operational Planning Data Environment.

2. OST shall deliver to requesting TSOs, in line with Article 68, additional information on modifications to the Network Topology or on operational agreements in such a way that an accurate representation of the system is provided for performing complete Operational Security analysis.

Article 62. Updates of Year-Ahead Common Grid Models

1. When OST considers a change in its best estimations of variables used for the establishment of Individual Grid Models referred to in Article 60 (1) significant in relation to Operational Security, OST sh.a shall update its Year-Ahead Individual Grid Models and deliver them to the ENTSO-E Operational Planning Data Environment.
2. Whenever changes are made to an Individual Grid Model in accordance with Article 62(1) the European Merging Function shall establish an updated Year-Ahead Common Grid Model.

Article 63. Week Ahead Common and individual grid models

1. When two or more TSOs consider it necessary for coordinating Operational Security Analysis, they shall define the most representative scenarios for analyzing the Operational Security of the Transmission System for the Week-Ahead time horizons.
2. When applicable, OST sh.ashall create or update its Individual Grid Models for the Week-Ahead in line with the scenarios according to Article 63(1), and make them available to the European Merging Function.

Article 64. Day Ahead (D-1) and Intraday Grid Models

1. OST shall implement ENTSO-E procedure on the provisions dealing with the gathering and merging of the D-1 and intraday Individual Grid Models into Common Grid Models. These provisions shall cover the following elements:
    a) data format;
    b) timeframes/ time granularity;

c) a procedure to handle Network Topology modification or operational agreements in order to manage Operational Security;
d) deadlines compatible with setting up Remedial Actions and the Capacity Calculation Process;
e) plausibility and quality control of datasets including the Individual Grid Models as well as Common Grid Models in line with points (4), (5) and (6) of this article;
f) a procedure for model improvement
g) tasks to be performed in regional level, schyncronus area, including time schedules for the different tasks in all time horizons;
h) specifications of the ENTSO-E Operational Planning Data Environment

2. OST shall create and deliver, via the ENTSO-E Operational Planning Data Environment its D-1 and intraday Individual Grid Models in accordance with the provisions defined pursuant to point 1 of this Article.
3. Individual Grid Models referred to in point (1) and (2) of this article shall contain at least the following variables:
   a) up to date Demand and Generation forecasts
   b) for Power Generating Facilities connected to Distribution Networks, aggregated Active Power output differentiated according to the type of primary energy source in line with data provided in accordance to Articles 113,116 and 117 of this Code
   c) transmission system topology; and
   d) remedial actions proposed for Constraints management
4. OST shall assess the accuracy of the variables referred to point (3) used to build its Individual Grid Models, comparing it with the actual values and implementing the principles defined pursuant to Article 68(1) (f).
5. If OST considers the accuracy of the variables referred to it in point (3) to be insufficient in relation to the Operational Security as a result of the assessment pursuant to point(4) of this article, OST shall perform an analysis to determine the causes of the inaccuracy. If the causes depend on the OST processes for creating the Individual Grid Models, that OST shall adapt the related processes to create more accurate results. If the causes depend on variables referred to in point (3) of this article, provided by other stakeholders, OST and those providers shall use all available economically efficient and feasible means under their control to improve these forecasts.
6. For D-1 and intraday Common Grid Models, TSOs shall check at least the following:
   a) the coherency of the connection status of interconnections;
   b) voltage deviation above the criteria defined in accordance with point(1) of this Article, for elements of the Transmission System located in the Observability Area of other TSOs;
   c) the coherency of Transitory Admissible Overloads of interconnections; and
   d) implausible Active Power and Reactive Power injections or withdrawals

Article 65. Operational Security Analysis in operational planning

1. OST shall perform coordinated Operational Security analyses at least at the following time horizons:
   a) Year-Ahead;
   b) Week-Ahead, when is applicable
   c) Day-Ahead (D-1);and

    d) Intraday
2. OST shall perform Operational Security Analyses for each of the time horizons specified in point (1) of this Article in N-Situation by simulating each Contingency from the OST Contingency List in accordance with Article 114 of this Code and verifying that the Operational Security Limits defined in accordance with Article 109(5), Article 109(6) and Article 109(8) of this Code, in the (N-1)-Situation are not exceeded.
3. When simulating each Contingency in accordance with point (2) of this Article, OST shall take into account the capabilities of the Significant Grid Users as defined in article 109 to 116 of this Code.
4. OST shall coordinate with neighboring TSO-s its Operational Security Analyses in accordance with the Article 113(3) and Article 114(3) and in accordance with Article 68 of this Network Code, in order to verify that Operational Security Limits affecting its own Responsibility Area are not exceeded
5. OST shall use as a minimum Common Grid Models described in Article 61,62,64 and when is relevant Article 67 to perform Operational Security Analyses referred to in article 66 and article 67.

Article 66. Year-Ahead up to and including Week-Ahead Operation Security Analyses

1. OST sh.a shall perform Operational Security Analyses for assessing that the Operational Security Limits of its Responsibility Area are not exceeded, taking into account all the Contingencies from its Contingency List and using the applicable Common Grid Models described in articles 58 to 64 and relevant information as described in Article 69
2. OST shall perform Operational Security Analyses referred to in point (1) of this Article, in accordance with the coordination methodology and processes described in Article 68(1)(g) in order to detect at least the following Network Constraints:
    a) Power flows and voltages over operational security limits
    b) breaches of Stability Limits of the Transmission System if applicable according to Article 116(4) and Article 116 (5);and
    c) violation of short-circuit thresholds of the Transmission System if applicable according to Article 112(3) of this Code.
3. When, as a result of Operational Security Analysis referred to in point (1) and (2) of this Article, OST detects possible Constraints, than shall prepare, if applicable with OSHE or Significant Grid Users, Non Costly Remedial Actions to solve the Constraint. If these are not available, this shall be considered an Outage Incompatibility and a coordination process according to Article 82 and Article 88 shall be initiated.

Article 67. D-1, Intra-day and real-time Operational Security Analyses

1. On a D-1 basis and within the intraday periods, OST shall perform Operational Security Analyses for assessing that the Operational Security Limits of its Responsibility Area are not exceeded. It shall take into account all the Contingencies from its Contingency List in order to detect possible Constraints and define with the affected TSOs and, if applicable, with OSHE or Significant Grid Users the appropriate Remedial Actions.
2. OST shall monitor demand and Generation forecasts and shall proceed to updated Operational Security Analysis when these forecasts lead to significant deviation in demand or Generation.
3. In undertaking the analysis pursuant to Article 67(1), OST shall take into account:
    a) the available updates of Generation and consumption data;
    b) possible significant deviation in demand or Generation due to uncertain weather forecasts

c) the results of the D-1 and intraday market processes; and
d) the results of the scheduling tasks described in Article 99 to 101 of this Code.

4. On a D-1 and intraday basis, if Constraints are detected, OST shall evaluate, in line with coordination principles defined in Article 68 and 69, the effectiveness of the joint Remedial Actions.
5. Close to Real-Time, when performing Operational Security Analysis in its Observability Area, OST shall use State Estimation (based on data of SCADA system).

Article 68. Methodologies for coordinating Operational Security Analysis

1. OST shall establish the methodology standardized to "Operational Handbook" of ENTSO-E per Synchronous Area, for Operational Security Analysis. This methodology shall at least cover:
   a) methods for assessing the influence of external elements;
   b) methods for definition of the Observability Area;
   c) Contingency Influence Thresholds above which Contingencies of external grid elements are deemed as External Contingencies, within OST Contingency List;
   d) common risk assessment principles, covering at least, for the Contingencies described in Article 114 of this Code:
      i. associated probability;
      ii. Transitory Admissible Overloads; and
      iii. impact of Contingencies;
   e) principles for the selection of the appropriate joint Remedial Actions;
   f) principles for assessing and dealing with uncertainties of Generation and demand, taking into account at least Reliability Margin.
   g) methodologies and processes for performing coordinated Dynamic Stability Assessment in line with this Code.

Article 69. Agreements for coordinating Operational Security

1. OST shall establish a multi-party agreement for European South-East region within which there is multilateral operational impact resulting from:
   a) electrical interdependencies between Responsibility Areas including but not limited to loop flows, voltage profiles, phase-shifting transformers, and HVDC influencing each other;
   b) power flow effects from changes in Generation patterns;or
   c) the integration of grid elements of a TSO within the Observability Area and the Contingency List of another TSO.
2. OST shall ensure the consistency and the efficiency of the coordination of Operational Security Analyses within the multi-party agreement referred to point (1) of this article. These multi-party agreement shall cover at least:
   a) governance and decision making procedures to be adopted by the concerned TSOs;
   b) Common processes for:
      i. sharing the information on external Contingencies in Contingency list affecting each TSO's Responsibility Area;
      ii. the evaluation of deviations from Operational Security Limits and their consequences, in accordance with the methodology referred to in Article 68(1);
      i. taking into account the information concerning the range of uncertainties regarding Generation and/or demand and its associated probability;
      ii. exchanging the information of the available joint pre-Fault and post-Fault; and
      iii. Remedial Actions; and
      iv. preparing and activating the most suitable joint Remedial Actions.

c) identification of the number and update frequency of intraday grid models, necessary to reassess the Operational Security;
d) compatible tools for performing common processes defined to point(2)(b) of this article;
e) the identification of any tasks within the common processes referred to in point (2)(b) of this article which are delegated;
f) processes for reviewing the contents or the perimeter of the multi-party agreement if so resulted from influence analysis in line with the common approach referred to in Article 68(1);
g) additional datasets, as needed, to the ones described in Article 58 to 64, including :
    i. protection Set Points or System Protection Schemes;
    ii. single line diagram and substations configuration;
    iii. additional grid models to represent specific situations;
h) necessary information concerning the range of uncertainties regarding Generation and/or demand and its associated probability for each Individual Grid Model.

Article 70. Outage Coordination-Outage Coordination Regions

1. OST shall coordinate the outage planning process (outage of grid elements for maintance) within its responsibility area.
2. OST will be part of multilateral agreement for the Southeast Europe region, in which it impacts, and within which the status of availability of significant assets will be coordinated and monitored.

Article 71. Regional coordination procedure

1. OST of an Outage Coordination Region shall define:
    a) the frequency, scope and type of coordination which shall take place at least for the Year-Ahead and Week-Ahead time horizons;
    b) arrangement to ensure the participation of Regional Security Coordination Initiatives operating in Region in the Outage Coordination Process; and
    c) procedures for the validation of the Year-Ahead Relevant Grid Element Availability Plans by all Outage Coordinating TSOs of the Outage Coordination Region.
2. OST shall participate in the Outage Coordination Process of its Outage Coordination Regions in accordance with paragraph 1 of this article.
3. OST shall provide all Outage Coordinating TSOs of its Outage Coordination Region with all relevant information at its disposal on those infrastructure relating to the Transmission System, Distribution Network, Power Generating Modules, or Demand Facilities that impact on the operation of the Responsibility Area of another TSO.
4. OST shall provide to OSHE and significant grid users connected to Transmission System located in its Responsibility Area with all relevant information at its disposal on the Transmission System related infrastructure projects that impact on the operation of the Distribution Network and/or significant grid user’s facilities.

Article 72. Methodology for assessing relevance of assets for the Outage Coordination Process

1. OST shall implement the coordinated methodology of ENTSOE , standardized per European Synchronous Area, for assessing the relevance of Power Generating Modules, Demand Facilities, and grid elements located in a Transmission System or in Distribution Network for the Outage Coordination Process.

2. The methodology referred to in paragraph 1 of this Article , shall include a procedure to quantify the impact of the Availability Status of Power Generating Modules, Demand Facilities, and grid elements located in a Transmission System, in a Distribution Network, or on Responsibility Areas of participating TSOs in Outage Coordinating process. This procedure shall be based on:
   a) Operational Security Analyses using established Common Grid Models;
   b) sensitivity analyses of power flows through the interconnected Network; and
   c) a threshold on the sensitivity of power flows, standardized per European Synchronous Area.
3. The methodology referred to in Article 72(1) shall be consistent with the methods for assessing the influence of external elements referred to in Article 68(1) (a).

Article 73.List of Relevant Power Generating Modules and Relevant Demand Facilities

1. OST shall apply the methodology established pursuant to Article 72 to assess the relevance of Power Generating Modules and Demand Facilities for the Outage Coordination Process.
2. OST shall establish a single list of Relevant Power Generating Modules and Relevant Demand Facilities for the Outage Coordination Process which shall contain only significant grid users.
3. The list of Relevant Power Generating Modules and Relevant Demand Facilities shall contain all Power Generating Modules and Demand Facilities for which the Availability Status impacts on another Responsibility Area to a level beyond the thresholds defined in the methodology established pursuant to Article 72 and for which paragraph (2) of this Article applies.
4. OST shall inform its National Regulatory Authority of the list of Significant Grid Users and for any Relevant Power Generating Modules and Relevant Demand Facilities shall:

   a) Inform the owners of the Relevant Power Generating Modules and the Relevant Demand Facilities about their inclusion in the list;
   b) inform OSHE on the Relevant Power Generating Modules and the Relevant Demand Facilities about their inclusion in the list.

Article 74. Re-assessment of the list of Relevant Power Generating Modules and Relevant Demand Facilities

1. Before 1 July of each calendar year, OST shall re-apply the methodology established pursuant to Article 72 for assessing the relevance of Power Generating Modules and Demand Facilities for the Outage Coordination Process.
2. When, pursuant to the assessment in paragraph 1, OST identify a need to update the list of Relevant Power Generating Modules and Relevant Demand Facilities , OST notify the Outage Coordinating OST and update this list as soon as reasonably practicable.

Article 75. List of Relevant Grid Elements

1. OST shall apply the methodology established pursuant to Article 72 for assessing the relevance of grid elements located in a Transmission System or in a Distribution Network for the Outage Coordination Process.
2. OST shall establish a single list of Relevant Grid Elements for the Outage Coordination Process.
3. The list of Significant Grid Elements shall contain:
   a) all grid elements located in a Transmission System or in a Distribution Network connecting Responsibility Areas;
   b) all grid elements located in a Transmission System or in a Distribution Network for which the Availability Status impacts on another Responsibility Area to a level beyond the thresholds defined in the methodology established pursuant to Article 72; and

    c) all Critical Network Elements.
4. The list of Relevant Grid Elements shall contain the types of information which shall be provided by each TSO to the ENTSO-E Operational Planning Data Environment, including at least:
    a) the reason for every unavailable status of a Relevant Grid Element;
    b) specific conditions that need to be fulfilled before executing an unavailable status of a Relevant Grid Element; and
    c) the time required to restore a Relevant Grid Element to service if necessary to maintain Operational Security.
5. OST shall make the list of Relevant Grid Elements available on the ENTSO-E Operational Planning Data Environment.
6. OST shall inform National Regulatory Authority of the list of Relevant Grid Elements and for any significant grid element included in the list, shall:
    a) Inform the owners and/or significant grid elements operators connected in transmission network, for their including in the list
    b) inform OSHE of the Relevant Grid Elements, connected in their network , about their inclusion in the list;

Article 76. Re-assessment of the list of Relevant Grid Elements

1. Before 1 July of each calendar year, OST shall re-apply the methodology established pursuant to Article 72 for assessing the relevance of grid elements, for the Outage Coordination Process.
2. When, pursuant to paragraph (1) of this Article ,OST identify a need to update the list of Relevant Grid Elements, OST notify the Outage Coordinating TSO-s and shall update this list as soon as reasonably practicable, the updated list shall be available too on the ENTSO-E Operational Planning Data Environment.

Article 77. Appointing Outage Planning Agents

1. For each Relevant Asset, the owner (the grid user) shall ensure that an Outage Planning Agent is appointed.
2. OST is (be appointed) the Outage Planning Agent for every Relevant Grid Element that is operated by her as an Outage Coordinating TSO.

Article 78. Treatment of Relevant Assets located in a Distribution Network

1. For the Relevant Assets that are located in a Distribution Network, OST shall coordinate the outage planning with the OSHE.

Article 79. General provisions on Availability Plans

1. The Availability Plans shall contain a separate Availability Status for each Relevant Asset with at least an hourly granularity.
2. For exchanging Availability Plans between Parties, Availability Statuses may be aggregated to a lower time granularity level if agreed by the exchanging Parties.
3. On the timeframes when Generation Schedules and Consumption Schedules are submitted to the OST according to Article 100, Availability Plans shall have a time granularity consistent with Generation Schedules and Consumption Schedules.
4. The Availability Status shall be one of the following three states:
    a) available: the Relevant Asset is capable of and ready for providing service, whether or not it is actually in operation;
    b) unavailable: the Relevant Asset is not capable of or ready for providing service;
    c) testing: the capability of the Relevant Asset for providing service is being tested.

5. The Availability Status “testing” shall only be used when there is a potential impact on the Transmission System, and shall be limited to the time periods:
   a) between first connection and final commissioning of the Relevant Asset; and
   b) directly following maintenance of the Relevant Asset.

Article 80. Long-term indicative Availability Plans

1. Two years prior to the start of the Year-Ahead coordination process, OST shall assess the indicative Availability Plans for Relevant Assets, provided by the Outage Planning Agents pursuant to Transparency Regulation.
2. Following this assessment, OST shall provide its preliminary comments, including detected Outage Incompatibilities, to all impacted Outage Planning Agents.
3. The assessment of OST shall be repeated every 12 months until the start of the Year-Ahead coordination process.

Article 81. Provision of Year-Ahead Availability Plan proposals

1. Before 1 August of each calendar year, for every Relevant Asset, the Outage Planning relevant Agent shall propose an Availability Plan for its Relevant Assets for the following calendar
2. Between 1 August and 1 December, all Outage Planning Agents referred to paragraph 1 in this Article, shall have the right to initiate changes to their proposed Availability Plan by sending a change request to OST.
3. OST shall handle the change requests received after the Year-Ahead coordination process has been finalized, hereby:
   a) respecting the order in which the change requests were received; and
   b) following the procedure set forth in Article 88(2)

Article 82. Year-Ahead coordination of the Availability Status of Relevant Assets with Outage Coordinating Planning Agents of Grid Users.

1. OST shall assess on a Year-Ahead horizon whether Outage Incompatibilities arise from the proposed Availability Plans provided in accordance with Article 81.
2. In the event that Outage Incompatibilities are detected, OST and all affected Outage Planning Agents shall coordinate their Availability Plans. OST shall:
   a) inform each affected Outage Planning Agent of the conditions to be fulfilled to relieve the detected Outage Incompatibilities;
   b) be entitled to request that one or more Outage Planning Agents submit an alternative Availability Plan fulfilling these conditions; and
   c) repeat the assessment pursuant to paragraph (1) of this Article to establish whether any Outage Incompatibilities remains
3. In the event that no alternative Availability Plan relieving all Outage Incompatibilities is submitted following a request from the Outage Coordinating TSO(s) pursuant to Article 35(2), this Outage Coordinating OST shall establish such an alternative Availability Plan. In that case, this Outage Coordinating OST shall:
   a) take into account the impact reported by the affected Outage Planning Agents;
   b) ensure the changes in the alternative Availability Plan are limited to what is strictly necessary to relieve the Outage Incompatibilities; and
   c) inform National Regulatory Authority, the affected OSHE and the affected Outage Planning Agents about the established Availability Plan, and the reasons which motivated its adoption.

Article 83. Year-Ahead coordination of the Availability Status of Relevant Assets with OSHE

1. OST shall coordinate the Availability Status of Relevant Grid Elements, interconnecting different Responsibility Areas and for which it is an Outage Planning Agent with the other Outage Coordinating TSOs of its Outage Coordination Region in accordance with the following principles:
   a) minimizing the impact on the market while preserving Operational Security; and
   b) using as a basis the proposed Availability Plans for Relevant Assets established in accordance with Article 81 and Article 82.
2. OST and OSHE shall plan the Availability Status of the Relevant Grid Elements for which they are the Outage Planning Agent and that are not interconnecting different Responsibility Areas in accordance with the following principles:
   a) minimizing the impact on the market while preserving Operational Security; and
   b) using as a basis the proposed Availability Plans for Relevant Assets established in accordance with Article 81 and Article 82 and the Availability Status of Relevant Grid Elements interconnecting different Responsibility Areas established in accordance with paragraph (1) of this article.
3. In case of Outage Incompatibilities, OST shall be entitled to propose a change to the proposed Availability Plans of the Relevant Assets connected with OSHE network and initiate coordination with the OSHE for any case of incompatibility.
4. In the event that OSHE has been unable to plan the unavailable Availability Status of a Relevant Grid Element, OSHE shall report to OST sh.a. In this case OST and all affected Outage Planning Agents shall use all available economically efficient and feasible means under their control in accordance with the national legal framework to plan the unavailable Availability Status of the Relevant Grid Element.
5. In the event that, having implemented the provisions of paragraph (4) of this article, the unavailable Availability Status of the Relevant Grid Element has not been planned, and if in the reasoned opinion of TSO, not planning this unavailable Availability Status would threaten Operational Security, the OST shall:
   a) take such actions as it deems necessary to plan this unavailable Availability Status while ensuring Operational Security, taking into account the impact reported to the Outage Coordinating OST by affected Outage Planning Agents;
   b) provide a notification of these actions to all affected Parties; and
   c) inform ERE and OSHE, and the affected Outage Planning Agents of the actions taken, the threats which required such actions to be taken and the rationale for using the chosen actions.

6. OST shall include all information at its disposal about grid-related conditions that need to be fulfilled and Remedial Actions that need to be taken before executing an unavailable Availability Status of a specific Relevant Grid Element on the ENTSO-E Operational Planning Data Environment alongside information on the Availability Plan.

Article 84. Provision of preliminary Year-Ahead Availability Plans

1. Before 1 November of each calendar year, OST shall provide the preliminary Year-Ahead Availability Plans for all Relevant Assets for the following calendar year to all other Outage Coordinating TSOs via the ENTSO-E Operational Planning Data Environment.

2. Before 1 November of each calendar year, for every Relevant Asset that is located in a Distribution Network, OST shall provide the preliminary Year-Ahead Availability Plan for this Relevant Asset to OSHE for every relevant asset.
3. The Availability Plans referred to in paragraph 1 and 2 of this article shall contain at least the information listed in Article 75(4).

Article 85. Validation of Year-Ahead Availability Plans within Outage Coordination Regions

1. OST shall analyze whether Outage Incompatibilities arise when combining all preliminary Availability Plans impacting its Responsibility Area.
2. In the event that Outage Incompatibilities impacting the Year-Ahead Availability Plans for Relevant Assets are identified, OST shall coordinate with the concerned Outage Planning Agents, OSHE and/or Outage Coordinating TSOs to find a solution.
3. Once a solution is found for each Outage Incompatibility, OST shall validate the Year-Ahead Availability Plans for all Relevant Grid Elements in accordance with the procedure established pursuant to Article 71(1) (c).

Article 86. Final Year-Ahead Availability Plans

1. Before 1 December of each calendar year, OST shall:
   a) finalize the Year-Ahead coordination process of Relevant Assets; and
   b) update the preliminary Year-Ahead Availability Plans for Relevant Assets on the ENTSO-E Operational Planning Data Environment.
2. Before 1 December of each calendar year, for every Relevant Asset, shall confirm the final Year-Ahead Availability Plan for this Relevant Asset to the appointed Outage Planning Agent.
3. Before 1 December of each calendar year, for every Relevant Asset that is located in a Distribution Network, OST shall provide the updated Year-Ahead Availability Plan for this Relevant Asset to the OSHE.
4. The Availability Plans referred to in Article 86(2), Article 86(3), shall contain at least the information listed in Article 75(4).

Article 87. Coordination processes in case of detected Outage Incompatibilities

1. OST shall conduct this process for the Relevant Assets of the Outage Planning Agents located in its Responsibility Area in line with the applicable national legal framework.
2. OST shall use the means at its disposal according to the applicable national legal framework to find a solution for the detected Outage Incompatibilities.
3. This Article shall apply to each coordination process that is initiated pursuant to the detection of Outage Incompatibilities according to Article 85 and Article 88.

Article 88. Updates to the Year-Ahead Availability Plans

1. After the finalization of the Year-Ahead coordination process in accordance with Article 86 and before real-time execution, all Outage Planning Agents shall have the right to initiate an adaptation of the coordinated Availability Plan.
2. Each Outage Planning Agent that initiates an adaptation of the coordinated Availability Plan of the Relevant Assets under its responsibility shall send a change request to the TSO. OST shall follow the following procedure:
   a) receive the change request;
   b) assess as soon as reasonably practicable whether Outage Incompatibilities arise as a result of this change to the coordinated Availability Plan of Relevant Assets;

c) in the event that Outage Incompatibilities are detected, initiate a coordination process involving OSHE , and all Outage Planning Agents for the Relevant Assets of which the Availability Status is impacted;
d) issue a reasoned decision on the change request at the end of the coordination process, validating the change request when no Outage Incompatibility is detected or no Outage Incompatibility remains after coordination, and rejecting the change request when not all of the detected Outage Incompatibilities can be solved after coordination;
e) incorporate the validated change request in the coordinated Availability Plan and notify all impacted Parties; and
f) update the ENTSO-E Operational Planning Data Environment, if the change request is validated.

3. When OST initiates an adaptation of the coordinated Availability Plan of Relevant Grid Elements shall follow the following procedure:
   a) assess as soon as reasonably practicable whether Outage Incompatibilities arise as a result of this change to the coordinated Availability Plan of Relevant Assets;
   b) send a change request and report detected Outage Incompatibilities to all other Outage Coordinating TSOs of its Outage Coordination Region(s);
   c) consider additional Outage Incompatibilities related to the change request detected by other Outage Coordinating TSOs of its Outage Coordination Region;
   d) in the event that Outage Incompatibilities are detected, initiate a coordination process involving Outage Planning Agents, affected Outage Coordinating TSOs, OSHE for the Relevant Assets of which the Availability Status is impacted;
   e) receive a reasoned decision on the change request from all parties that are impacted by the adaptation of the coordinated Availability Plan at the end of the coordination process, validating the change request when no Outage Incompatibility is detected or no Outage Incompatibility remains after coordination and rejecting the change request when not all of the detected Outage Incompatibilities can be relieved after coordination;
   f) incorporate the validated change request in the coordinated Availability Plan and notify all impacted Parties; and
   g) update the ENTSO-E operational planning data environment if the change request is validated.
4. In the event that, OST detects that Outage Incompatibilities arise according to Article 66(3), than OST shall initiate a coordination process involving Outage Planning Agents, OSHE and affected Outage Coordinating TSOs for the Relevant Assets of which the Availability Status is impacted.

Article 89. Detailing the testing status of Relevant Assets

1. The Outage Planning Agent of a Relevant Asset for which the testing Availability Status is declared shall provide to TSO, and if connected to OSHE as early as reasonably practicable, and no later than one month before the start of the testing Availability Status with:
   a) a detailed test plan;
   b) an indicative Generation or Consumption Schedule of the concerned Relevant Asset
   c) changes to the Transmission System or Distribution Network Topology if the concerned Relevant Asset is a Relevant Grid Element.

2. The Outage Planning Agent of a Relevant Asset for which the testing Availability Status is declared shall provide to TSO, and OSHE if connected to a Distribution Network with an update of the information required in point (1) of this article as early as reasonably practicable.
3. Information received pursuant to point (1) and (2) of this Article, for a Relevant Asset for which the testing Availability Status is declared, OST shall inform all other Outage Coordinating TSOs of its Outage Coordination Region on request of these Outage Coordinating TSOs.
4. In case the Relevant Asset referred to in paragraph (1) and (2) is a Relevant Grid Element which interconnects two Responsibility Areas, the Outage Coordinating TSOs operating the two concerned Responsibility Areas shall coordinate in order to agree on the information to be provided pursuant to paragraph 1 and 2 of this article.

Article 90. Processes for handling Forced Outages

1. OST shall establish and manage a coordination process to ensure the available or unavailable Availability Status of Relevant Assets in its Responsibility Area in case of Forced Outages and when Operational Security is endangered. The process shall:
   a) be used only in cases where all attempts to agree to a negotiated solution have been exhausted; and
   b) ensure, to the extent possible, that the technical limits of the Relevant Assets are respected.
2. In the event of a Forced Outage of a Relevant Asset, the Outage Planning Agent shall inform OST and OSHE depend on the connection point,on this Forced Outage as soon as reasonably practicable and provide it with information on:
   a) the reason for the Forced Outage;
   b) the expected duration of the Forced Outage; and
   c) if applicable, the impact of the Forced Outage on the Availability Status of other Relevant Assets under its responsibility.
3. Whenever OST sh.a detects that one or several Forced Outages referred to in Article 90(2) has the potential of leading the Transmission System out of a Normal State, OST sh.a shall inform the concerned Outage Planning Agent of the latest time at which Operational Security can be maintained without the Relevant Asset(s) in Forced Outage being available. Outage Planning Agent of the Relevant Asset(s) shall inform the OST sh.a of his possibility to respect this time or shall justify their deviation from this time .
4. Following all updates to the Availability Plan due to Forced Outages and in accordance with the timeframe established in [Regulation on Transparency and provision of information in electricity market], OST sh.ashall update the ENTSO-E Operational Planning Data Environment with the most recent information.

Article 91. Real-time execution of the Availability Plans

1. Each Power Generating Module owner/operator shall ensure that Relevant Power Generating Modules under its responsibility which are declared available are ready to produce electricity pursuant to their declared technical capabilities when necessary to maintain Operational Security, except in case of Forced Outages.
2. Each Power Generating Module Owner/operator shall ensure that all Relevant Power Generating Modules under its responsibility that were declared unavailable do not produce electricity.
3. Each Demand Facility Owner shall ensure that all Relevant Demand Facilities under its responsibility that were declared unavailable do not consume electricity.
4. Each Relevant Grid Element owner shall ensure that all Relevant Grid Elements under its responsibility that were declared available, are ready to transport electricity pursuant to

their declared technical capabilities when necessary to maintain Operational Security, except in case of Forced Outages.

5. Each Relevant Grid Element owner shall ensure that all Relevant Grid Elements under its responsibility that were declared unavailable do not transport electricity.
6. If specific grid-related conditions apply for the execution of an unavailable status of a Relevant Grid Element in accordance with this paragraph, OST, or OSHE shall assess if these conditions are fulfilled before the real-time execution of the unavailable Availability Status. If not, the unavailable Availability Status, shall not be executed.
7. Upon the request of OST, before executing an unavailable Availability Status of a Relevant Asset which puts the Transmission System out of Normal State, each concerned party shall delay the corresponding unavailable Availability Status according to the instructions of the OST sh.ato the extent possible while respecting the technical and safety limits
8. Upon the request from OST, before executing a planned test of Relevant Assets which puts the Transmission System out of Normal State, each concerned party shall delay the corresponding test according to the instructions of OST to the extent possible while respecting the technical and safety limits.

Article 92. Forecasts for assessing Adequacy

1. OST shall make any forecasts used for Responsibility Area Adequacy analyses in accordance with Article 93 or Article 96 available to all other TSOs through the ENTSO-E Operational Planning Data Environment.

Article 93. Responsibility Area Adequacy analyses

1. When performing Responsibility Area Adequacy analyses, OST sh.ashall assess the possibility for the sum of Generation within its Responsibility Area and cross border import capabilities to meet the total demand within its Responsibility Area under various operational scenarios, taking into account the required level of Active Power Reserves in line with Chapter VI of this code.
2. When performing an Adequacy analysis in accordance with paragraph (1) of this article, OST sh.a shall:
   a) use the latest Availability Plans and the latest available data for:
      i. capabilities of Power Generating Modules in accordance with Article 120(5), Article 122 and Article 123 of this Code and their Availability Statuses; and
      ii. cross border capacities;
   b) shall take into account
      i. contributions of Generation from Renewable Energy Sources; and
      ii. demand;
   c) assess the probability and expected duration of an absence of Adequacy
3. As soon as reasonably practicable, OST sh.a shall inform:
   a) National Regulatory Authority and when applicable any affected party, when an absence of Adequacy is detected within its Responsibility Area; and
   b) all TSOs through the ENTSO-E Operational Planning Data Environment when Generation within its Responsibility Area alone is insufficient to meet the demand.

Article 94. Summer and winter Generation Adequacy outlooks and methodology

1. OST shall implement the common methodology defined by ENTSOE to establish annual summer and winter Generation Adequacy outlooks including:

a) the criteria used to define the set of operational scenarios by Responsibility Area, taking into account their probability of occurrence;
b) the method to assess the Adequacy of each Responsibility Area in accordance with Article 93 taking into account pan-European scenarios;
c) cross border capacities for exchanges of electricity;
d) the data to be exchanged between TSOs; and
e) conditions for reviewing the methodology established.

2. OST shall perform annual summer and winter Generation Adequacy outlooks before 21 May and 21 November of each calendar year respectively.

Article 95. Responsibility Area Adequacy up to and including Week Ahead

1. From the establishment of the annual summer and winter Generation Adequacy outlooks in accordance with Article 94, up to and including the Week-Ahead timeframe, OST sh.a shall monitor changes on the Availability Status of Power Generating Modules, on demand estimations, on Renewable Energy Sources estimations and on cross border capacities.
2. OST shall perform an updated Responsibility Area Adequacy assessment in accordance with paragraph (1) of this article when the OST sh.a considers the changes to be significant in light of maintaining Adequacy.

Article 96. Responsibility Area Adequacy D-1 and intraday

1. OST shall perform a Responsibility Area Adequacy analysis on a D-1 and intraday basis by using:
   a) Market Participant Schedules
   b) forecasted demand;
   c) forecasted Generation from Renewable Energy Sources;
   d) Active Power Reserves in accordance with the data provided pursuant to Article 122 of this Code
   e) cross border capacities
   f) capabilities of Power Generating Modules in accordance with the data provided pursuant to Article 120 Article 122 and Article 128 of this Code and their Availability Statuses; and
   g) capabilities of Demand Units with Demand Side Response in accordance with the data provided pursuant to Article 129 and Article 130 of this Code and their Availability Statuses.
2. OST shall evaluate:
   a) the maximum level of import and export capacity compatible with its Responsibility Area Adequacy;
   b) the expected duration of a potential absence of Adequacy; and
   c) the expected energy not served in the absence of Adequacy.
3. If Adequacy is not fulfilled according to the analysis referred to paragraph (1), OST sh.a shall inform ERE or other relevant national authority. The OST sh.a shall provide its relevant national authority with an analysis of the causes of the absence of Adequacy as soon as reasonably practicable.

Article 97. Ancillary Services

1. OST shall monitor the availability of Ancillary Services.
2. At least for Active Power and Reactive Power, either on an autonomous basis or in coordination with other TSOs, OST sh.a shall:

a) design and set up procedures for the procurement of Ancillary Services;

b) monitor on the basis of data provided in accordance with articles 108 to 142 whether the level and location of available capacity of Ancillary Services allows the fulfilment of operational security;
c) manage the procedures designed in accordance with Article 97(2)(a); and
d) use all available economically efficient and feasible means under its control to procure the level of Ancillary Services required.

3. OST shall publish the required levels of Active Power Reserves.
4. If OST decide to exchange Active Power Reserves between LFC Areas, they shall establish one or more procedures in accordance with Chapter VI of this Code.
5. OST shall communicate the available level of Active Power Ancillary Services to other TSOs upon their request.

Article 98. Reactive Power Ancillary Services

1. OST shall assess in all operational planning timeframes whether its available Reactive Power sources are sufficient to ensure the Operational Security of the Transmission System, in line with Article 109 of this Code.
2. In order to increase the efficiency in operation of the elements of its Transmission System, OST shall monitor:
a) the available Reactive Power capacities of Power Generating Facilities;
b) the available Reactive Power capacities of Transmission Connected Demand Facilities;
c) the available Reactive Power capacities of OSHE.
d) the transmission connected available equipment dedicated to providing Reactive Power; and
e) the ratios of Active Power and Reactive Power at the interface between Transmission Systems and Distribution Networks.

3. Whenever the level of Reactive Power Ancillary Services is not sufficient for maintaining Operational Security, OST sh.a shall:

a) inform neighboring TSOs; and
b) prepare Remedial Actions for activation in line with Article 109(9) of this Code.

Article 99. Establishment of scheduling processes

1. For each Power Generating Facility and Demand Facility to which requirements for scheduling in accordance with the applicable national legal framework apply, the concerned owner/operator shall ensure that a Scheduling Agent is appointed. Each Market Participant and Market Coupling Operator to which requirements for scheduling in accordance with the applicable national legal framework apply, shall appoint a Scheduling Agent.
2. OST shall establish the provisions necessary to process Schedules, provided from Scheduling Agents, in accordance with the applicable national legal framework.
3. When a Scheduling Area covers more than one Responsibility Area, the TSOs responsible for these Responsibility Areas shall agree on which one operates the Scheduling Area.

Article 100. Notification of schedules within Scheduling Areas

1. Each Scheduling Agent within a Scheduling Area, except Scheduling Agents of Market Coupling Operator shall submit to the OST sh.athe following Schedules:

a) Generation Schedules;
b) Consumption Schedules;
c) Internal Commercial Trade Schedules; and
d) External Commercial Trade Schedules.

2. Each Scheduling Agent of a Market Coupling Operator shall submit Schedules to the TSOs operating a Scheduling Area involved in the market coupling in accordance with the applicable national legal framework. These Schedules include:

   a) Net Position related to the Scheduling Area;
   b) External Commercial Trade Schedules as:
      i. multilateral exchange between the Scheduling Area and a group of other Scheduling Areas; or
      ii. bilateral exchange between the Scheduling Area and another Scheduling Area as requested by concerned TSO.
   c) Internal Commercial Trade Schedules between Scheduling Agents of Market Coupling Operators and Scheduling Agents of Nominated Electricity Market Operators, if requested by concerned TSO.

3. Before adopting an External OST sh.a Schedule, all involved TSOs shall agree on the content of such an External Schedule.

Article 101. Coherence of schedules

1. OST shall develop and implement a process to ensure its area internal balance for Generation Schedules, Consumption Schedules, External Commercial Trade Schedules and External OST sh.a Schedules.
2. Each Scheduling Agent of a Market Coupling Operator shall follow the process described above and provide requesting TSOs with the values of External Commercial Trade Schedules of each Scheduling Area involved in market coupling in the form of Aggregated Netted External Schedules.

Article 102. Provision of information to other TSOs

1. OST shall calculate and provide any requesting OST sh.a with:

   a) Aggregated Netted External Schedules; and
   b) Netted Area AC Position when the Scheduling Area is interconnected to other Scheduling Areas via AC transmission links.

2. When required for the creation of Common Grid Models, in accordance with Article 64(2), OST sh.a operating a Scheduling Area shall provide any requesting TSO with:

   a) Generation Schedules; and
   b) Consumption Schedules.

Article 103. General provisions for ENTSO-E Operational Planning Data Environment

1. ENTSO-E shall implement and shall administer an ENTSO-E Operational Planning Data Environment for the storage of all relevant information for operational planning.
2. TSO shall be responsible for providing and updating the relevant information to this environment. OST shall have access to all information contained on the ENTSO-E Operational Planning Data Environment.

Article 104. Individual Grid Models, Common Grid Models and Operational Security Analysis

1. The ENTSO-E Operational Planning Data Environment shall store all Individual Grid Models and related relevant information for all relevant time horizons defined in this Network Code
2. The information on Individual Grid Model contained on the ENTSO-E Operational Planning Data Environment shall allow for the merging into Common Grid Models by the European Merging Function.
3. All Common Grid Models shall be made available on the ENTSO-E Operational Planning Data Environment.
4. For the Year-Ahead time horizon, the following information shall be made available on the ENTSO-E Operational Planning Data Environment:

   a) description of the scenarios referred to in Article 59;
   b) Year-Ahead Individual Grid Model per OST sh.a and per scenario defined in accordance with Article 60; and
   c) Year-Ahead Common Grid Model per scenario defined in accordance with Article 61.

5. For the D-1 and intraday time horizons, the following information shall be made available on the ENTSO-E Operational Planning Data Environment:

   a) D-1 and intraday Individual Grid Models per OST and according to the time granularity defined pursuant to Article 64;
   b) Scheduled Exchanges at the relevant time instances per Scheduling Area;
   c) D-1 and intraday Common Grid Models according to the time granularity defined pursuant to Article 64;and
   d) a list of the prepared and agreed upon pre-Fault and post-Fault Remedial Actions identified to cope with cross Responsibility Area Constraints.

Article 105. Outage Coordination Process

1. The ENTSO-E Operational Planning Data Environment shall contain a module for the storage and sharing of all relevant information for the Outage Coordination Process.
2. This information shall include at least:

   a) Availability Status of Relevant Grid Elements including at least all information described in accordance with Article 754);
   b) Availability Status of Relevant Power Generating Modules including; and
   c) Availability Status of Relevant Demand Facilities including, outage period, specific conditions for execution of the outage and time required to restore service if necessary to maintain Operational Security.

Article 106. System Adequacy

1. The ENTSO-E Operational Planning Data Environment shall store all relevant information for coordinated Adequacy analysis.
2. This information shall contain at least:

   a) the season-ahead system Adequacy data provided by the individual TSOs;
   b) the season-ahead pan-European system Adequacy analysis report;
   c) forecasts used for Adequacy in line with Article 92; and
   d) Information about a lack of Adequacy in line with Article 93(3) (b).

Article 107. Performance indicators

1. OST shall contribute to the annual reporting developed pursuant to the common incidents classification scale, adopted by ENTSO-E

2. This report shall include the results of quality monitoring of the following Performance Indicators relevant for operational planning:
   a) Indicator OPS 1A – an indicator about the number of events in which an incident contained in the Contingency list led to a degradation of system operation conditions;
   b) Indicator OPS 1B – an indicator about the number of events counted by indicator OPS 1A in which a degradation of system operation conditions occurred as a result of unexpected discrepancies of demand or Generation forecasts;
   c) Indicator OPS 2A – an indicator about the number of events in which there was a degradation in system operation conditions due to an Out-of-Range Contingency;
   d) Indicator OPS 2B – an indicator about the number of events counted by indicator OPS 2A in which a degradation of system operation conditions occurred as a result of unexpected discrepancies of demand or Generation forecasts; and
3. Indicator OPS 3 – an indicator about the number of events leading to a degradation in system operation conditions due to lack of Active Power Reserves. For OPS 1A, OPS 1b, OPS 2A, OPS 2B and OPS 3, the indicator shall only record the events leading to a degradation in system operation conditions, ranked at Scale 1, Scale 2 or Scale 3, according to the Operational Security Ranking defined in Article 132(3) of this Code

CHAPTER V

Network Code on Operational Security

Article 108. Subject matter and scope

1. Network Code on Operational Security defines the minimum requirements and principles for operational security, technical needs for safety in real time operation, security of supply and achieving the main goal to maintain continuous operation of Albanian Transmission System interconnected with the European Transmission System (synchronous area of Continental Europe).
2. OST manages and exercises its responsibilities based on the requirements and principles of operational security by ensuring the functioning of the system at a high level of coordination, reliability, quality and stability.
3. Operational Security Code defines the technical framework, harmonized and sustainable, including the implementation of all the necessary processes required for the secure operation, taking into account the current and expectations for rapid growth of renewable energy and their impact on system operation.
4. Operation Security Code is mandatory for all participants in the electricity market, both in normal situations as well as in emergencies. Further, the Code identifies relevant provisions of General Emergency situation, Black Out State, Restoration and coordination of the operating system in a common and coherent way across the entire synchronous area.
5. For the purposes of this Code, OST will classify generation modules as "distribution network connected" and "transmission network Connected". Demand Facility units shall be classified according to the criteria defined by ENTSO-E.
   The Significant Grid Users within the scope of this Network Code are:
   a) existing and new generating modules as type "connected to distribution network" and as type "connected to transmission system" according to the criteria of ENTSO-E.
   b) Existing and New Transmission Connected Demand Facilities according to the criteria defined by ENTSOE and all Existing and New Demand Facilities Connected to Distribution Networks
   c) Significant Demand Facilities and Aggregators in the case where they provide Demand Side Response directly to the TSO;
   d) Redispatching Aggregators and Providers of Active Power Reserve according to Chapter VI of this Code.
6. In the implementation of the technical and other requirements set in this Network Code, each OST shall comply with good industry practice.

Article 109. System States

1. OST shall in real-time operation differentiate five System States, based on the Operational Security Limits according to Article 111 and Article 113, while respecting the Contingency Analysis provisions according to Article 114 and the frequency control management provisions according to Article 110. On this basis, OST shall classify the System State of its Transmission System applying the following criteria:

a) Normal state:
    i. voltage and power flows are within the Operational Security Limits defined according to Articles 111 and Article 113 in accordance with Article 109(5) and frequency is within the frequency limits for the Normal State as defined in Chapter VI.
    ii. Active and Reactive Power reserves are sufficient to withstand Contingencies from the Contingency List defined according to Article 114; and
    iii. operation of its Responsibility Area is and will remain within Operational Security Limits even after a Contingency from the Contingency List defined according to Article 114 and after effects of Remedial Actions;
b) Alert State
    i. voltage and power flows are within their Operational Security Limits defined according to Articles 111 and 113,and
    ii. at least one of the following conditions is fulfilled:
        a) Active Power Reserve requirements are not fulfilled with lack of more than 20% of the required amount of any of the following: FCR, FRR and RR according to the dimensioning in article 165,168 and 170 for more than 30 minutes and with no means to replace them;
        b) frequency is within the frequency limits for the Alert State as defined in article 148.
        c) at least one Contingency from the Contingency List defined according to Article 114 can lead to deviations from Operational Security Limits, even after effects of Remedial Actions;
c) Emergency State:
    i. there is at least one deviation from Operational Security Limits and times defined according to Articles 111 and 113 in accordance with Article 109(5); or
    ii. frequency is outside the frequency limits for the Normal State and outside the frequency limits for the Alert State as defined in Chapter VI.
    iii. at least one measure of the System Defense Plan is activated; or
    iv. there is a complete loss of all tools and facilities defined according to paragraph (15) of this article for more than 30 min
d) Blackout state (black-out):
    i. loss of more than 50% of load in the OST's Responsibility Area; or
    ii. total absence of voltage for at least 3 minutes in the OST's Responsibility Area and triggering Restoration plans;
e) Restoration:
    i. Procedures are implemented to bring frequency, voltage and other operational parameters within the Operational Security Limits defined according to Articles 110, 111 and 112 in accordance with Article 109(5); and
    ii. Demand Facilities are connected at a pace decided by the TSOs in charge of Restoration, depending on the technical capability and feasibility of the Transmission System resources and Significant Grid Users which are Power Generating Facilities.

2. In order to determine the System State, OST shall at least every 15 minutes perform Contingency Analysis in real-time, monitoring the parameters against a common set of criteria defined according to Article 109(1), while taking into account the effect of potential Remedial Actions and measures of the System Defense Plan.

3. OST shall monitor in real-time the following parameters within its Responsibility Area based on real-time telemetry and measurements from its Observability Area, taking into account the structural and real-time data defined in Article 117 to 130:
   a) active and Reactive Power flows;
   b) busbar voltages;
   c) frequency and Frequency Restoration Control Error of its LFC Area;
   d) active and Reactive Power reserves; and
   e) generation and consumption
4. OST shall use all available economically efficient and feasible means under its control to maintain in real-time its Transmission System in a Normal State. For this purpose, OST shall plan Remedial Actions according to the requirements defined in chapter IV detailed in Article 57 to 117 and implement them when necessary in line with provisions of paragraph (12) of this article.
   For each element of its Transmission System, each OST shall define before its use in operation the Operational Security Limits for:
   a) voltage ranges according to Article 111;
   b) short-circuit current ranges according to Article 112; and
   c) current limits in terms of thermal rating including the Transitory Admissible Overloads.
5. When defining the Operational Security Limits, OST sh.a shall take into account the capabilities required for Significant Grid Users which are Power Generating Modules Demand Facilities in order to ensure that voltage and frequency ranges in Normal and Alert States do not lead to their disconnection
6. In the case of a change in any equipment or device of an element of its Transmission System, OST sh.a shall validate and when necessary update the Operational Security Limits.
7. For each Interconnector, OST sh.ashall coordinate with the interconnected TSO, the common definition of Operational Security Limits including: current limits in terms of thermal rating and Transitory Admissible Overload and voltage ranges defined according to Article 111(12).
8. In real-time operation, if Transmission System is in the Alert State, OST sh.a shall in coordination with the TSOs with which it has a multi-party agreement concluded and with OSHE and Significant Grid Users directly connected to Transmission System:
   a) implement the pre-fault Remedial Actions which are rendered necessary to restore the Normal State and to prevent the propagation of the Alert State outside of its Responsibility Area; and
   b) identify the post-fault Remedial Actions which shall be implemented in case of occurrence of a Contingency.
9. In real-time operation, if Transmission System is in Emergency State, OST sh.a shall, in coordination with the TSOs with which it has a multi-party agreement concluded with OSHE and Significant Grid Users that are involved in system defense and Restoration, implement the measures of the System Defense Plan which are rendered necessary to restore the Alert or Normal State, and to prevent the propagation of Emergency State outside of its Responsibility Area.
   a) In real-time operation, if Transmission System is not in a Normal State and if that System State is qualified as Wide Area the OST sh.a shall: and
   a) inform all TSOs about the System State of its Transmission System via an IT tool for real-time data exchange at pan-European level;

b) provide additional information on the elements of its Transmission System which are part of the Observability Area of the other TSOs, to those TSOs; and
c) coordinate the joint Remedial Actions with the TSOs with which it has a multi-party agreement concluded in accordance with Article 69 of this Code.

10. In real-time operation or during operational planning, when preparing and implementing a Remedial Action including Redispatching or Countertrading or a measure of the System Defense Plan which has an effect on other TSOs, OST sh.a shall cooperate with those TSOs in order to assess the impact of such Remedial Action or a measure of the System Defense Plan within and outside of its Responsibility Area and to coordinate with those TSOs with which it has a multi-party agreement concluded in accordance with Article 69 of Grid Code.
11. When preparing a Remedial Action, including Redispatching or Countertrading, or a measure of the System Defense Plan, OST shall, in the case of mutual implications, cooperate with the Significant Grid Users and OSHE with Connection Point directly to the Transmission System. OST sh.a shall ex-ante cooperate with the OSHE involved with the Remedial Action or the measure of the System Defense Plan, to assess the impact of the Remedial Action on the Distribution Network, and coordinate with those DSOs to select the Remedial Action or the measure of the System Defense Plan which enhances Operational Security for all involved Parties. OSHE shall ex-ante provide all the information necessary for this cooperation.
12. When implementing a Remedial Action or a measure of the System Defense Plan, OSHE and each Significant Grid User with Connection Point directly to the Transmission System shall execute the instructions given by the OST sh.a to maintain Operational Security of the Transmission System, without undue delay. If the OST does not instruct Significant grid users connected to the Distribution Network, OSHE shall communicate the instructions of the OST to the Significant Grid Users.
13. OST shall prepare/design its systems in order to ensure the availability, reliability and redundancy of the following critical tools and facilities, which are required for system operation:

    a) facilities for monitoring the System State of the Transmission System, including State
    b) Estimation applications;
    c) means of communication with control centres of other TSOs;
    d) tools for Operational Security Analysis.

OSHE or Significant Grid Users which are involved in balancing, Ancillary Services, system defense, Restoration or delivery of real-time operational data according to Articles 121,124, 127, 128, 129 and 130, the OST, the OSHE and Significant Grid Users shall, cooperate and coordinate in ensuring the availability, reliability and redundancy of these tools and facilities.

14. OST shall adopt a business continuity plan detailing TSO's responses to a loss of critical tools and facilities, containing provisions for maintenance, replacement and development of critical tools and facilities. The business continuity plan shall be reviewed at least annually and updated as necessary or following any significant change of critical tools and facilities or relevant system operation conditions. The business continuity plan contents shall be shared with OSHE and Significant Grid Users to the extent to which they are affected.
15. OST shall establish a confidential Security Plan containing a risk assessment of critical assets owned or operated by the TSO, to major physical or cyber threat scenarios to be conducted by the Member State with an assessment of the potential impacts. OST sh.a shall have in place organizational, logistical and other physical measures which shall cover the major findings from the risk assessment. The plan shall be kept under regular review to limit the impact of threats and maintain the secure operation of the TSO's network and IT systems and the European

interconnected Transmission Systems. These reviews can lead to the setting up of intruder detection, access control, procedures, training, alert processes, preventive procedures, restoration plans and other counter-measures.

Article110. Frequency control management

1. OST shall contribute to the Load-Frequency Control Structure according to the requirements for frequency quality defining parameters and provisions for Active Power Reserves as defined in Chapter VI of this Code.
2. In the case where the frequency is beyond the Maximum Steady-state Frequency Deviation, but within the range 49 – 51 Hz, OST as a member of Synchronous Area shall apply commonly agreed Remedial Actions following coordinated procedures agreed among all TSOs of that Synchronous Area in order to recover frequency back within the range of Maximum Steady-state Frequency Deviation.
3. In the case where the frequency is outside of the range 49 – 51 Hz, TSOs shall apply commonly agreed measures of the System Defense Plan following coordinated procedures agreed among all TSOs of that Synchronous Area in order to recover and restore frequency within the time ranges coordinated.
4. Significant grid Users shall stay connected with the grid at least within the frequency ranges and time limits defined as follow:

   - unlimited time periods for frequency 49.0Hz-51.0Hz
   - at least for 30 min per frequency from 47.5Hz- 48.5Hz;
   - for frequency of 48.5 - 49 Hz to stay connected with the grid for a period time not less than the period for 47.5 Hz - 48.5 Hz;
   - min. per frequency 51.0Hz-51.5Hz

5. While being in Emergency State, the system frequency can exceed the range of 49 – 51 Hz. OST sh.a shall take into account that Significant Grid Users which are Power Generating Modules and Demand Facilities can disconnect after the time periods and take this into account in planning of Remedial Actions and measures of the System Defense Plan.
6. Each Significant Grid User with Connection Point directly to the Transmission System shall adopt the criteria and conditions (operations rules) including requirements for permission to re-synchronize, defined by the OST sh.a for re-synchronization. Re-synchronization can be done only with the approval of the NDC(National Dispatch Center)
7. OSHE shall adopt the criteria and conditions (operation rules) including requirements for permission to re-synchronize, defined by the OST sh.a for re- synchronization of the Significant Grid Users with Connection Point to its Distribution Network. Also, OSHE shall in turn ensure that those criteria and conditions are agreed upon with the Significant Grid Users with Connection Point directly to the Distribution Network.
8. OSHE shall automatically disconnect at specified frequencies and in predefined Active Power steps, defined by the TSO. Significant Grid User which is a Power Generating Module shall automatically disconnect at specified frequencies, defined by the TSO.
9. OST making use of the provisions from Article 110(6), 110(7) and 110(8) shall coordinate the frequency related Remedial Actions with all other TSOs of its Synchronous Area and shall ensure the necessary coordination with OSHE.
10. OST shall operate its LFC Area with sufficient upward and downward Active Power Reserve, which may include shared or exchanged reserves, to face imbalances of demand and supply within its LFC Area. OST sh.a shall control the Frequency Restoration Control Error as defined

in Chapter VI of this Code in order to reach the required frequency quality within the Synchronous Area in cooperation with the TSOs in the same Synchronous Area.

11. OST shall monitor close to real-time generation and exchange schedules, power flows, node injections and withdrawals and other parameters within its LFC Area relevant for anticipating a risk of a frequency deviation and when needed take joint measures to limit their negative effects on the balance between generation and demand in coordination with other TSOs of its Synchronous Area.
12. OST shall activate, or set up the conditions necessary to ensure the activation of Active Power Reserves at different time-frames according to the provisions of Chapter VI in order to maintain:
    a) the scheduled Active Power exchange of its LFC Area,
    b) System Frequency and Frequency Restoration Control Error.
13. In the case of a scheduled exchange or sharing of reserves, the TSO within whose Responsibility Area the reserves are connected and the TSO receiving the reserves, together with TSOs which connect the aforementioned TSOs in the case they are not directly connected, shall carry out a common Operational Security Analysis and adopt the necessary measures to ensure that the resulting power flows do not endanger the Operational Security Limits during the exchange of reserves or activation of reserve .
14. OST shall be entitled to use actions to improve System Frequency quality as defined in Chapter VI. These actions can include restrictions on the Ramping Rates of Significant Grid Users and HVDC interconnectors.

Article 111. Voltage control and Reactive Power management

1. Voltage conditions in transmission system are directly depended on the situation of reactive power to the system nodes. To be compensated, for an excessive consumption of reactive power, OST shall ensure that efficient and effective producers generate / absorb enough reactive power, except reactive power absorbed/generated from other sources installed in the Transmission System or Demand Facilities. OST should also provide a continuous balance and locally sufficient of reactive power, to be capable to maintain proper voltage levels. In this context, the purpose of voltage controll and reactive power management is to provide that:
    a) Voltage levels and reactive power flows of reactive power sources are monitored, controlled and maintained in real time within the limits of Operational Security, in order to protect the Transmission System equipment and ensuring the voltage stability,
    b) Adequate reserves of reactive power is available immediately, in generators in operation, reactors and capacitors, in order to provide the technical operational of the entire power system, and be able to restore normal state after failures.

   For this purpose, it is set to become permanent on-line monitoring and exchange of information, carried out by TSOs in the respective areas of observation.
   In accordance with Article 109 (4), OST will use all available possible means and economically efficient under its control, to maintain the voltage levels in stable conditions, within the limits of Transmission System Operational Security thresholds, as well as in normal states and after the occurrence of a contingency, as specified in the table below, in line with synchronous area of Continental Europe standards.

Voltage level	Voltage range	Time duration
110 and 220 kV	0.90 p.u – 1.118 p.u	unlimited

400 kV	0.90 p.u – 1.05 p.u	unlimited

For voltage levels below 110 kV, OST will coordinate the implementation of the voltage thresholds, with the Distribution System Operator and Network Users connected directly to the Transmission System.

2. OST can agree wider voltage ranges or limited times for operation with OSHE and Significant Grid Users with Connection Point directly to the Transmission System, while respecting the provisions of Article 109(8).
3. Power Generating Modules of type "connected to transmission system" shall remain connected at least within the voltage and time ranges defined by OST within operational security limits. Power Generating Modules with Connection Point directly to the Transmission System shall inform the TSO about their capabilities and in so doing they shall declare the voltages and time they can withstand without disconnection. OST can require modifications of Power Generating Module capabilities if this is necessary for maintaining Operational Security.
4. Significant Grid Users which are demand facilities , shall not disconnect due to a Disturbance at least within the voltage and time ranges as following:
   - unlimited time duration per voltage 0.9 pu-1.05pu;
   - as specified in coordination with neighboring TSO's per voltage range 1:05 p.u - 1.0875 p.u,
   - for 60 min. per voltage range 1.0875 p.u to 1.10 p.u
5. All Significant Grid Users which are Demand Facilities shall inform OST about their capabilities compared to the voltage requirements and in so doing they shall declare the voltages and time they can withstand without disconnection. OST can require modifications of Demand Facilities capabilities if this is necessary for maintaining Operational Security If voltages at a Connection Point to the Transmission System are outside the ranges from Table above, OST shall apply voltage control and Reactive Power management measures in order to restore voltages and time within the ranges specified according paragraph 3 and 4.
6. In Emergency State, if voltages at the Connection Points of Power Generating Modules of type "connected to Transmission System" exceed the ranges from the Table, OST shall take into account that Significant Grid Users connected to the Transmission System might be disconnected after the time limits defined in paragraph 3 and 4 of this article.
7. For Significant Grid Users that are not subject to requirements of the above paragraphs, OST shall take into account in its Operational Security Analysis the voltage values at which each of these Significant Grid Users may disconnect.
8. OST shall implement the provisions from the Article 111(1) to Article 111(7) in a coordinated way at the level of Synchronous Area.
9. OST shall ensure Reactive Power reserve, with adequate volume and time response, in order to keep the voltages within its Responsibility Area within the Operational Security Limits ranges defined in Table.
10. Significant Grid Users which are not Demand Facilities shall automatically or manually, disconnect at specified voltages in the specified timeframe, defined by the OST or by the OSHE if this Demand Facility has Connection Point to the Distribution Network. OST making use of this provision shall respect its multi-party agreements concluded in accordance with Article 69 of the Code and shall ensure the coordination with OSHE.
11. In accordance with Article 109(8), OST in coordination with interconnected TSO's shall define the voltage and/or Reactive Power flow limits on these Interconnectors commonly, in order to use the Reactive Power resources in the most effective way and ensure adequate voltage control.

12. OST shall coordinate Operational Security Analysis with other TSOs in accordance with the multi-party agreements concluded in accordance with Article 69 of this Code in order to ensure the respecting of the Operational Security Limits for voltage ranges in its Responsibility Area and within the Responsibility Areas of these TSOs.
13. OST shall define the Reactive Power set-points, power factor ranges and voltage set- points for voltage control , which shall be maintained by the Significant Grid Users or OSHE , while respecting the provisions of Article 109(13). OSHE shall in turn be able to define voltage control instructions to Significant Grid Users connected to the Distribution Network in order to respect the instructions of the TSO.
14. OST shall be entitled to use all available Reactive Power resources with Connection Point to the Transmission System within its Responsibility Area to ensure effective Reactive Power management and maintaining the ranges of voltage Operational Security Limits defined in this Network Code.
15. OST shall operate or direct the operation of Reactive Power resources within its Responsibility Area including blocking of automatic voltage/Reactive Power control of transformers, in order to maintain Operational Security Limits and to prevent voltage collapse of the Transmission System.
16. OST shall coordinate and define the voltage control actions with OSHE, the Significant Grid Users with Connection Point directly to the Transmission System, and with neighboring TSOs. OST sh.a in coordination with OSHE shall be entitled to direct Significant Grid Users with Connection Point to the Distribution Network to follow voltage control instructions if this is relevant for the voltage and Reactive Power management of the Transmission System.
17. OST shall maintain voltage ranges and OSHE and Significant Grid User which is a Transmission Connected Demand Facility shall maintain the power factor at Connection Points within the ranges specified in Article 111(13)
18. If voltage deterioration jeopardizes Operational Security or threatens to develop into a voltage collapse in either N or (N-1)-Situation the OST sh.a shall be entitled to instruct the OSHE, and Significant Grid Users with Connection Point directly to the Transmission System, to block automatic voltage and Reactive Power control of transformers or to follow other voltage control instructions. As a consequence of these measures directed by the TSO, the OSHE may have to disconnect Significant Grid Users which are Demand Facilities in order to avoid jeopardizing the Transmission System. This is part of the Defense Plan.

Article 112. Short-circuit current management

1. In accordance with Article 109(5), OST sh.a shall define the maximum short-circuit current at which the rated capability of circuit breakers and other equipment is exceeded and the minimum short-circuit current for correct operation of protection equipment. OST sh.a shall apply operational measures to prevent or relieve a deviation from these short-circuit current limits.
2. In accordance with Article 109(4), OST sh.a shall use all available economically efficient and feasible means under its control to maintain the short-circuit current within the limits defined in Article 112(1) for the Contingencies of the Contingency List at all times and for all protection equipment. A deviation from these conditions is allowed only during switching sequences.
3. OST shall perform short-circuit current and power calculation according to the best available data and its own practice approaches or according to agreed international standards.
4. When assessing the compliance with the limits defined according to Article 112(1), OST shall consider operational conditions that provide the highest conceivable level of short-circuit current, considering also the short-circuit contribution from other Transmission Systems and Distribution Networks.

5. OST shall perform short-circuit calculations in order to evaluate the impact of directly interconnected TSOs, Transmission Connected Distribution Networks, on the short-circuit current level. Where a Transmission Connected Distribution Network has an impact on short-circuit current levels it has to be modelled in the Transmission System short-circuit calculations.

Article113. Power flow management

1. OST shall define Operational Security Limits for power flows on each Transmission System element within its own Responsibility Area in accordance with Article 109(5) and Article 109(8).
2. OST shall maintain Active Power flows within the Operational Security Limits defined in accordance with Article 109(5) when the system is in Normal State and after the occurrence of a Contingency from the Contingency List defined according to Article 114(1).
3. OST shall perform Operational Security analysis based on the forecast and real-time operational parameters from its Observability Area. OST sh.a shall coordinate Operational Security analysis with the other TSOs in accordance with the multi-party agreements concluded in accordance with Article 69 of the Code in order to ensure the respecting of the Operational Security Limits for power flows in its Responsibility Area.
4. OST shall be entitled to use Redispatching of available Significant Grid users with Connection Point directly to the Transmission System or to the Distribution Network to maintain Operational Security.
5. In the (N-1)-Situation in Normal State OST sh.a shall keep power flows within the Transitory Admissible Overloads, preparing and executing Remedial Actions including Redispatching, to be applied within the time allowed for Transitory Admissible Overloads.

Article 114. Contingency analysis and handling

1. OST shall define the Contingency List, including Internal and External Contingencies, within its Observability Area, for which it shall be checked whether any of these Contingencies endangers the Operational Security of the TSO's Responsibility Area. The Contingency List at least include Ordinary Contingencies and may include Exceptional Contingencies defined according to paragraph (5) of this article.
2. In order to identify the Contingencies which endanger the Operational Security of its Responsibility Area and to identify the necessary Remedial Actions, each OST shall perform Contingency Analysis in its Observability Area in real-time operation and in operational planning.
3. OST shall perform Contingency Analysis on the basis of the real-time system operation parameters periodically, according to Article 109(2) of this Code. OST shall ensure that potential deviations from the Operational Security Limits in its Responsibility Area which are identified by the Contingency Analysis do not endanger the Operational Security of its Transmission System or of the interconnected Transmission Systems.
4. OST shall assess the risks associated with the potential effects of Contingencies and prepare Remedial Actions after testing each Contingency from its Contingency Lists and after assessing whether it can maintain its Transmission System within the Operational Security limits in the (N-1)-Situation. The starting point for the Contingency Analysis in the N-Situation shall at any time be the up-to-date Topology of the Transmission System including planned outages. In the case of an (N-1)-Situation caused by an unplanned outage, OST shall apply Remedial Actions in order to ensure that the Transmission System is restored within Operational Security Limits as soon as reasonably practicable and that this (N-1)-Situation becomes the new N-Situation.
5. OST shall include Internal and External Contingencies in the Contingency List. External Contingencies shall be defined in line with the methodology developed according to the

provisions in the Code. OST shall differentiate between Ordinary, Exceptional and Out-of-Range Contingencies, taking into account their probability of occurrence. In the treatment of so classified Contingencies, OST shall apply the following principles:

a) OST shall classify Contingencies for its own Responsibility Area;
b) when and as long as conditions significantly increase the probability of an Exceptional Contingency, the OST shall include this Exceptional Contingency in its Contingency List. The OST shall determine the Remedial Actions necessary to maintain its Transmission System within Operational Security Limits or to mitigate the impact of Exceptional Contingencies as far as reasonably practical and economically efficient;
c) when and as long as out of the ordinary conditions increase the probability of an Out-of- Range Contingency, the OST shall use all available economically efficient and feasible means under its control to prepare Remedial Actions to mitigate the impact of these very exceptional conditions;
d) OST shall determine the Ordinary and Exceptional Contingencies based on the up- to-date topology
e) in order to account for Exceptional Contingencies with high impact on its own or neighboring Transmission Systems, or with a high probability of occurrence, OST shall include such Exceptional Contingencies in its Contingency List which shall be reassessed and if necessary the Contingency List readjusted in the case of significantly changed operational conditions;
f) OST shall contribute to the development of a common methodology and criteria for coordination and, as far as technically feasible and economically efficient, harmonization of the key principles for establishment of Contingency Lists across the Synchronous Areas.

6. OST shall prepare Remedial Actions including Redispatching pursuant to Article 109(12) and Article 109(13), or Countertrading to cope with any Contingency from its Contingency List for which potential deviation from Operational Security Limits is identified in accordance with Article 109(5).
7. TSO shall, upon any relevant change in real-time operation or in Transmission System topology, reassess the Contingencies from its Contingency List to be taken into account according to Article 114(5) in Normal State and adjust the prepared Remedial Actions.
8. OST shall apply Remedial Actions upon identification of a Contingency during Contingency Analysis, for which there is a danger of not being able to cope efficiently and in a timely manner with the conditions occurring after that Contingency.
9. If after a Contingency the Transmission System is not compliant with the (N-1)-Criterion, the OST shall initiate Remedial Actions to recover compliance with the (N-1)-Criterion as soon as reasonably practicable. If there is a risk of a post-Contingency Disturbance propagation involving interconnected TSOs, the OST shall initiate Remedial Actions as soon as possible. Non-compliance with the (N-1)-Criterion is acceptable:

   a) during switching sequences;
   b) as long as there are only Local consequences within the TSO’s Responsibility Area;
   c) During the time period required to activate the Remedial Actions.

10. OST shall ensure that its Observability Area used for Contingency Analysis is based upon sufficiently accurate real-time data to allow for convergence of load-flow calculations.
11. OSHE and Significant Grid Users which are Power Generating Facilities of type “connected to distribution network” and type “connected to transmission system” shall deliver all information

for Contingency Analysis as requested by the TSO, including forecast and real-time data, with possible data aggregation according to Article 128(3).

12. OST shall coordinate its Contingency Analysis in terms of coherent Contingency Lists at least with the TSOs from its Observability Area and in accordance with the multi-party agreements concluded in accordance with Article 69. OST shall cooperate at least with other TSOs from its Observability Area and deliver all information for Contingency Analysis including forecast and real-time data according to the provisions article 117 to 130 of this Code.
13. OST shall contribute to establishing the Common Grid Model (regional). This contribution shall include the data for the Common Grid Model according to the defined contents and timeframes according to the provisions in article 117 to 130 of this code.
14. OST shall inform the TSOs from its Observability Area, about their External Contingencies taken into account in its Contingency list.
15. OST shall inform and coordinate with the relevant TSOs, prior to implementation, any significant topological changes in parts of its Responsibility Area involving Transmission System elements which are included as External Contingencies of Contingency Lists of other TSOs.

Article 115. Protection

1. OST shall install the necessary protection and backup protection equipment within its Transmission System in order to efficiently and effectively protect Transmission System elements and to coordinate with the protection of the equipment of Significant Grid Users, from effects of Faults in the Transmission System.
2. TSO shall at least every five years review and analyze the protection strategy and concepts and when necessary adapt the protection functions to ensure the correct functioning of the protection and the maintaining of Operational Security. After every protection operation having impact outside of its own Responsibility Area, OST shall assess whether the protection system in its Responsibility Area worked as planned and shall undertake corrective actions if necessary.
3. OST shall operate the protection of its Transmission System with Set-Points that ensure reliable, fast and selective fault clearing, including backup protection for Fault clearing in case of malfunction of the main protection system.
4. OST shall install the necessary protection and backup protection equipment within its Transmission System in order to automatically prevent Disturbance propagation which can endanger the Operational Security of the interconnected Transmission System.
5. TSO shall coordinate with interconnected TSOs the protection Set-Points for the Interconnectors and inform and coordinate with those TSOs before changing the settings.
6. When OST is using a System Protection Scheme(SyPS), the OST sh.a shall:
   a) perform analysis in order to ensure that each SyPS acts selectively, reliably and effectively. In the analysis of SyPS, the OST sh.a shall evaluate the consequences for the Transmission System in the event of an incorrect SyPS function, taking into account the interaction with affected TSOs
   b) verify that the SyPS has a comparable reliability to the protection systems used for the primary protection of Transmission System elements
   c) Operate the transmission system with SyPS within operational security defined , pursuant with Article 109(5) dhe 109(6); and operate the Transmission System with the SyPS within the Operational Security Limits determined according to Article 109(5) and Article 109(6); and

d) Coordinate SyPS functions, activation principles and Set-Points with interconnected TSOs and affected DSOs, Closed Distribution Network and Significant Grid Users with Connection Point directly to the Transmission System.

7. TSO shall define a Low Frequency Demand Disconnection Scheme with common principles and in coordination with the OSHE and the TSOs of its Synchronous Area. Every change to the conditions and settings of LFDD shall be implemented in coordination with OSHE and TSO's of Synchronous Area.
8. OST shall define and implement actions for over-frequency in cooperation with Significant Grid Users which are Power Generating Facility Owners and in coordination with the TSOs of its Synchronous Area.

Article116. Dynamic stability management

1. OST shall monitor the dynamic state of the Transmission System in terms of Voltage, Frequency and Rotor Angle Stability by off-line studies, wide area measurements, or other approaches according to paragraph (5) of this article, including the exchange of relevant data with other TSOs if necessary, in order to be able to take the necessary Remedial Actions when the Transmission System Operational Security is at a risk.
2. OST shall ensure, in the case of stability problems due to poorly damped inter-area oscillations affecting several TSOs, that coordinated Dynamic Stability Analysis shall be performed on the Synchronous Area level as soon as reasonably practical. Each TSO is obliged to provide data as requested for this analysis.
3. OST shall perform Dynamic Stability Assessment (DSA) studies in order to identify the Stability Limits and potential stability problems in its Transmission System. DSA studies shall be coordinated between the TSOs within each Synchronous Area and shall be done for the whole or relevant parts of the Synchronous Area. These studies can be offline.
4. Where a TSO identifies a potential mutual influence of Voltage, Rotor Angle or Frequency Stability with other interconnected Transmission Systems, OST shall contribute to the coordination of approaches to the DSA, including provision of data needed for DSA, preparation of joint Remedial Actions including the cooperation procedures between the TSOs required to relieve wide area oscillations
5. In deciding the approach for DSA, OST shall apply the following rules:

   a) If with respect to the Contingency List, steady-state limits are reached before Stability Limits, the OST shall base its DSA only on the offline stability studies carried out in the longer term operational planning phase;
   b) If under planned outage conditions, with respect to the Contingency List, steady-state limits and Stability Limits are close to each other or Stability Limits are reached before steady-state limits, the OST shall perform a DSA in the day ahead operational planning phase whilst these outage conditions remain. The OST shall prepare Remedial Actions to be used in real-time operation if necessary; and
   c) If the network is in the N-Situation with respect to the Contingency List and Stability Limits are reached before steady-state limits, the OST shall perform a DSA in all phases of operational planning and have a capability to re-assess the Stability Limits as soon as reasonably practical after a significant change in conditions is detected.

6. If the DSA indicates a violation of Stability Limits, the OST shall implement measures to keep the Transmission System stable. These measures may involve Significant Grid Users which are Power Generating Modules.

7. OST shall ensure that the Fault clearing times for Faults that may lead to Wide Area system instability are less than the Critical Fault Clearing Time calculated by the OST in its Dynamic Stability Assessment.
8. OST as all TSOs from a Synchronous Area shall develop and implement the methodology for the definition of minimum inertia required to maintain Operational Security and to prevent violation of Stability Limits identified pursuant to paragraph (3) of this article. OST shall be entitled to define and deploy in operation the minimum inertia in its own Responsibility Area, according to the defined methodology and obtained results.

Article117. General requirements for data exchange

1. OST shall use the best available data and information which reflect as closely as possible the real and forecasted situation in the Transmission System.
2. OST shall minimize inaccuracies and uncertainties and continuously ensure high quality of the data and information used.
3. OST shall be entitled to gather the information which is required for the Operational Security Analysis and related to the following items, as further detailed in Article 118 to 130 of this Code.
   a) generation;
   b) consumption;
   c) schedules;
   d) balance positions;
   e) planned outages and substation topologies; and
   f) Own forecasts.

   This information shall be transformable into the injections and withdrawals at each node of the TSO's own Transmission System model and shall respect requirements described in this Code to be gathered in a Common Grid Model.
4. OST shall determine the scope of the data exchange with the Significant Grids Users defined in this Chapter, according to the following categories:
   a) structural data
   b) scheduling and forecast data
   c) real time data
   d) individual instructions by OST or OSHE
5. OST shall implement the ENTSO-E instruction(approved by all Schyncronus Area TSO's) regarding with key organizational requirements, roles and responsibilities in relation to the data exchange, published in the ENTSO-E website and shall encompass the following issues:
   a) obligations among the TSOs to communicate without undue delay to all neighboring TSOs any changes in the protection settings, thermal limits and technical capacities at the Interconnectors between their Responsibility Areas;
   b) obligations of OSHE directly connected to the Transmission System to inform within the agreed timescales of any changes in the data and information scope and contents from this Network Code;
   c) obligations for the adjacent OSHE and/or between the downstream OSHE and upstream OSHE to inform each other within agreed timescales of any change in the data and information scope which are defined in Article 117 to 130 this Network Code;

d) obligations of the Significant Grid Users to inform TSO's or OSHE within the timescales, about any relevant change in the scope and contents of the relevant data from this Chapter of Network Code;
e) Detailed contents of the data and information referred to in this Chapter and in a coherent way with the data exchange provisions in other Network Codes and the EU legislation. These detailed definitions shall include but not be limited to: main principles, type of data, communication means, format and standards to be applied, timing and responsibilities;
f) The time stamping and periodicity for the data and information to be provided by DSOs and Significant Grid Users, to be used by the TSO's systems at the different timescales. At least the frequency of information exchange for real-time data, scheduled data and update of structural data shall be defined; and
g) Reporting formats of the data and information referred to in this Chapter and in a coherent way with the data exchange provisions in other Network Codes.

6. OST and OSHE shall cooperate in order to define and agree on effective processes for providing and managing data exchanges between them, including, where required for efficient network operation, the provision of data related to Distribution Networks and Significant Grid Users. Such exchanges shall be governed by the principles of efficiency and proportionality.
7. Data related to commissioned network installations at the Connection Point to the Transmission System shall be available to Significant Grid Users and OSHE which are connected at that Connection Point.
8. OST and OSHE shall agree on the exact scope of additional information concerning commissioned network installations, to be exchanged in each case. OST shall make this information available to OSHE or Significant Grid Users of its Responsibility Area.
9. OST can entrust Regional Security Coordination Initiative with some of the tasks that it shall perform in accordance with this Network Code, while retaining the sole responsibility and liability as a TSO. In this case, the OST shall inform other TSOs, about this delegation, so that these Regional Security Coordination Initiatives can get all the data and information needed to perform the tasks entrusted to them.

Article118. Structural and forecast data exchange between TSO

1. OST shall exchange with Neighboring TSOs the structural information related to the Observability Area including at least:
   a) substations' regular Topology and other relevant data by voltage level;
   b) transmission lines;
   c) transformers connecting the OSHE, Significant Grid Users which are Demand Facilities and Power Generating Facilities;
   d) Maximum and minimum active and Reactive Power of Significant Grid Users which are Power Generating Modules;
   e) phase-shifting transformers;
   f) high voltage DC lines;
   g) reactors, capacitors and static VAR compensators; and
   h) Operational Security Limits defined by each TSO according to Article 109(5).

2. OST shall exchange with Neighboring TSOs the protection Set-Points of the lines included as external Contingencies in neighboring TSOs Contingency Lists to allow protection coordination between the different Transmission Systems.
3. In order to support coordinated Operational Security Analysis and the establishment of the Common Grid Model, OST shall exchange with other TSOs according to the provisions chapter IV at least the following data:
   a) topology of the 220 kV and higher voltage Transmission System within its Responsibility Area;
   b) a model or an equivalent of the Transmission System with voltage below 220 kV with significant impact to its own Transmission System; and
   c) the forecasted aggregate sum by primary energy source of injection and withdrawal in every node of the Transmission System for the different timeframes. This data shall correspond to the best forecast available at the OST level. The resulting forecast situation in the Transmission System shall be as realistic and accurate as possible.
4. In order to support coordinated Dynamic Stability Assessment, OST shall, when required in according to Article 116(2), exchange with other TSOs within the relevant part of the Synchronous Area the necessary data for DSA. Concerning Significant Grid Users which are Power Generating Modules, the OST shall provide the necessary data at least on:
   a) electrical parameters of the alternator suitable for DSA, including total inertia;
   b) protection models;
   c) alternator and prime mover;
   d) step up transformer description;
   e) minimum and maximum Reactive Power;
   f) voltage and speed controller models; and
   g) prime movers and excitation system models suitable for large disturbances.

   Concerning tap changers, description of existing on load tap changers, step up and network transformers, the OST shall provide the necessary data on:
   a) regulation type; and
   b) voltage regulation range.

   Concerning HVDC lines and FACTS devices, the OST shall provide the necessary data on dynamic models of the device and its associated regulation suitable for large disturbances.

Article 119. Real-time data exchange between TSOs

1. In accordance with Article 109(11)(a), OST shall exchange with all other TSOs in its Synchronous Area the necessary data on the System State of its Transmission System using the IT tool for real-time data exchange at pan-European level, including:
   a) Frequency Restoration Control Error or an equivalent parameter;
   b) measured Active Power exchanges between LFC Areas;
   c) aggregated generation in feed;
   d) System State in accordance with Article 109(1);
   e) set-value of the FR controller; and
   f) power exchange via the Virtual Tie-Lines.

2. TSOs shall exchange with the TSOs from its Observability Area the following data from its own Transmission System:

    a) actual substation Topology;
    b) Active and Reactive Power in line bay, including transmission, distribution and lines connecting Significant Grid User;
    c) Active and Reactive Power in transformer bay, including transmission, distribution and Significant Grid User connecting transformers;
    d) Active and Reactive Power in Power Generating Facility bay;
    e) regulating positions of transformers, including phase-shifting transformers;
    f) measured or estimated busbar voltage;
    g) Reactive Power in reactor and capacitor bay or from a static VAR compensator; and
    h) restrictions on Active and Reactive Power supply capabilities with respect to the Observability Area

Article 120. Structural data exchange between OST and OSHE within the TSO's Responsibility Area

1. TSO shall define the Observability Area of the Transmission Connected Distribution Networks, which is relevant to accurately and efficiently determine the System State, based on the methodology developed according to the provisions of Chapter IV of the Code.
2. In those cases where a Distribution Network (or a part of it) is not a Transmission Connected Distribution Network but whose electrical influence is deemed as significant by the OST for the proper representation of the system behavior, such Distribution Networks shall be defined by the TSO as being part of the Observability Area defined according to paragraph (1) of the Code.
3. OSHE shall provide to OST sh.a the structural information related to the Observability Area referred to in paragraph (1) and (2) of this article including, but not limited to:

    a) substations by voltage;
    b) lines that connect the substations from a) above;
    c) transformers from the substations from a) above; Significant Grid Users; and
    d) reactors and capacitors connected to the substations from a) above.

4. OSHE shall provide to the TSO, updated structural information about the elements of the Observability Area referred to in paragraph 1 and 2 of this article, periodically, at least every six months.
5. OSHE shall provide to OST sh.a the total aggregated generating capacity of all Power Generating Modules type "with connection point to distribution network", their primary energy source, and the related information concerning their frequency behavior.

Article 121. Real-Time data exchange between TSOs and OSHE within the TSO's Responsibility Area

1. OSHE shall provide in real-time to OST sh.a the information related to the Observability Area referred to in Article 120(1) and Article 120(2), comprising:

    a) actual substation Topology;
    b) Active and Reactive Power in line bay;
    c) Active and Reactive Power in transformer bay;
    d) Active and Reactive Power injection in Power Generating Facility bay;
    e) tap positions of transformers connecting to the Transmission System;
    f) busbar voltages;
    g) Reactive Power in reactor and capacitor bay

h) best available data for aggregated generation in the OSHE area; and
i) Best available data for aggregated consumption in the OSHE area.

Article 122. Structural data exchange between TSO, owners of Interconnectors or other lines and Power Generating Modules directly connected to the Transmission System

1. Each Significant Grid User which is a Power Generating Facility Owner operating a type "connected to transmission system" Power Generating Modules, shall provide at least the following data to the TSO:
   a) general data of the Power Generating Module, including installed capacity and primary energy source;
   b) turbine and Power Generating Facility data including time for cold and warm start;
   c) data for short-circuit calculation;
   d) Power Generating Facility transformer data;
   e) Frequency Containment Reserve (primary reserves) data according to the definition and requirements of Articles 143 to 189 for Power Generating Facilities offering or providing this service;
   f) Frequency Restoration Reserve data, according to the definition and requirements of article 169 for Power Generating Modules that participate in this service;
   g) Replacement Reserve (tertiary reserves) data for Power Generating Modules that participate in this service;
   h) data necessary for Restoration;
   i) data and models necessary for performing dynamic simulation;
   j) protection data; and
   k) voltage and Reactive Power control capability.
2. TSO may request any Power Generating Facility Owner operating a Power Generating Module with Connection Point directly to the Transmission System, to provide further data needed for Operational Security Analysis.
   Each HVDC Interconnector or Line owner shall provide at least the following data to the TSO:
   a) name plate data of the installation;
   b) transformers data;
   c) data on filters and filter banks;
   d) reactive compensation data;
   e) Active Power control capability;
   f) Reactive Power and voltage control capability;
   g) active or reactive operational mode prioritization if exists;
   h) frequency response capability;
   i) dynamic models for dynamic simulation;
   j) protection data; and
   k) Fault Ride Through capability.
3. Each AC Interconnector or Line owner shall provide at least the following data to the TSO:
   a) name plate data of the installation;
   b) electrical parameters; and
   c) associated protections.

Article123. Scheduled data exchange between TSO, owners of Interconnector or other lines and Power Generating Modules directly connected to the Transmission System

1. Each Significant Grid User which is a Generating Module with Connection Point directly to the Transmission System shall inform the OST sh.a on a Day-Ahead and Intra-Day basis of its Active Power output and Active Power reserves amount and availability and, without delay, about its scheduled unavailability or Active Power capability restriction.
2. Each Significant Grid User which is a Power Generating Facility Owner operating a Power Generating Module with Connection Point directly to the Transmission System shall provide to the OST any forecast restriction in the Reactive Power control capability.
3. Each HVDC Interconnector owner or owner other than the TSO, shall provide to the OST data its scheduled unavailability or Active Power restriction:

   Article 124. Real-Time data exchange between TSO, owners of Interconnector or other lines and Power Generating Modules directly connected to the Transmission System

4. Each Significant Grid User which is a Power Generating Facility Owner operating a Power Generating Module connected directly to transmission system, including its own house load, shall provide to the OST in real- time the following information:
   a) position of the circuit breakers at the Connection Point or another point of interaction agreed with the TSO;
   b) active and Reactive Power at the Connection Point or another point of interaction agreed with the TSO; and
   c) in the case of Power Generating Facility with consumption other than auxiliary consumption, net active and Reactive Power.
5. Each HVDC or AC Interconnector owner or an owner of the HVDC or AC line , within the OST Responsibility Area, shall provide the following data referred to the Connection Point to the TSOs in real-time:
   a) position of circuit breakers
   b) operational status; and
   c) active and reactive power

Article 125. Structural data exchange between TSO, OSHE and Significant Grid Users according to Article 108(5) (a) and Article 108(5) (d) connected to the Distribution Network

1. Each Significant Grid User according to Article 108(5)(a) and Article 108(5)(d) Power Generating Facility Owner connected to the Distribution Network shall at least provide the following data to its TSO and/or to its DSO:
   a) general data of the Power Generating Module, including installed capacity and primary energy source or fuel type;
   b) Frequency Containment Reserve (primary reserves) data for Power Generating Facilities offering or providing this service;
   c) Frequency Restoration Reserve (secondary reserves) data for plants that participate in this service;
   d) Replacement Reserve data for Power Generating Modules that participate in this service;
   e) protection data;
   f) Reactive Power control capability;
   g) capability of remote access to the circuit breaker;

h) data necessary for performing dynamic simulation voltage level and location of each Power Generating Module.

Organization of the data exchange shall be defined according to the key organizational requirements, roles and responsibilities established in Article 117(6) to Article 117(8).

2. Each Significant Grid User affected by the Article 153(1), shall inform the OST and/or the OSHE to which it has Connection Point, within the agreed time but before first commissioning or before any changes of the existing installation, about any change in the scope and the contents of the data according to Article 125(1). Organization of the data exchange shall be defined according to the key organizational requirements, roles and responsibilities established in Article 117(5).

Article 126. Scheduled data exchange between TSO, OSHE and Significant Grid Users according to Article 108(5) (a) and Article 108(5) (d) connected to the Distribution Network

1. Each Significant Grid User which is a Power Generating Facility Owner according to the Article 108(5)(a) and Article 108(5)(d) and with Connection Point to the Distribution Network, shall provide its TSO and/or its DSO with its scheduled unavailability, Active Power restriction and its forecast scheduled Active Power output at the Connection Point. Organization of the data exchange shall be defined according to the key organizational requirements, roles and responsibilities established in Article 117(6) to Article 117(8).
2. Each Significant Grid User which is a Power Generating Facility Owner according to Article 108(5)(a) and Article 108(5)(d) shall provide to its TSO and/or its DSO any forecasted restriction in the Reactive Power control capability. Organization of the data exchange shall be defined according to the key organisational requirements, roles and responsibilities established in Article 117(6) to Article 117(8).

Article 127. Real-Time Data exchange between TSO, OSHE and Significant Grid Users according to Article 108(5) (a) and Article 108(5) (d) connected to the Distribution Network

1. Each Significant Grid User which is Power Generating Facility Owner according to Article 108(5)(a) and Article 108(5)(d) connected to the Distribution Network, shall provide to its TSO and/or its DSO in real-time the following information:
   a) status of the switching devices and circuit breakers at the Connection Point; and
   b) Active and Reactive Power flows, current, and voltage at the Connection Point.

   Organization of the data exchange shall be defined according to the key organizational requirements, roles and responsibilities established in Article 117 (6) to Article 117(8).
2. TSO shall define in coordination with the responsible OSHE whether and which Significant Grid Users might be exempted from providing the real-time data directly to the OST whereas the real-time data of such Significant Grid Users needs to be delivered by responsible DSOs to the OST in an aggregated form.

Article 128. Data exchange between TSO, OSHE and Significant Grid User according to Article 108(5) (a) and Article 108(5) (d) connected to the Distribution Network

1. OSHE shall provide to OST the information specified in Articles 125,126 and 127 when and to the extent requested by the TSO.
2. OST shall make available to the DSO to whose Distribution Network significant Grid Users are connected, the information specified in Articles 125,126 and 127 as requested by the DSO.

3. OST may request further data from any Significant Grid User according to the Article 108(5) (a) and Article 108(5) (d) which is a Power Generating Facility Owner with Connection point to the Distribution Network, if this is necessary for Operational Security Analysis and validation of models.

Article 129. Data exchange between OST and Demand Facilities directly connected to the Transmission System

1. Transmission Connected Demand Facilities shall provide the following structural data to the OST:
   a) electrical data of the transformers connected to the Transmission System;
   b) characteristics of the load of the Demand Facility; and
   c) characteristics of the Reactive Power control.
2. Each Transmission Connected Demand Facility shall communicate to the OST, as a minimum, its scheduled active and forecast reactive consumption on a day-ahead and intraday basis, including any changes of these schedules or forecast.
3. Each Transmission Connected Demand Facility shall communicate to the OST any forecast restriction in the Reactive Power control capability.
4. Each Transmission Connected Demand Facility which participates in Demand Side Response shall inform the OST about the structural minimum and maximum power to be curtailed.
5. Each Demand Facility directly connected to the Transmission System shall communicate to the OST in real-time the following information:
   a) active and Reactive Power at the Connection Point; and
   b) minimum and maximum power to be curtailed.
6. Each Demand Facility directly connected to the Transmission System shall describe to its OST its behavior at the voltage ranges according to the provisions in Article 111.

Article 130. Data exchange between OST and Demand Facilities connected to the Distribution Network or Aggregators

1. The following requirements shall be defined by the OST in coordination with OSHE. Each Significant Grid User which is a Demand Facility connected to the Distribution Network and which participates in Demand Side Response, other than through an Aggregator, shall communicate to its OST or via its DSO to the OST the following scheduled and real-time data:
   a) structural minimum and maximum Active Power available for Demand Side Response; and the maximum and minimum duration of any potential usage of this power for Demand Side Response;
   b) forecast of unrestricted Active Power available for and any planned Demand Side Response;
   c) real-time Active and Reactive Power at the Connection Point; and
   d) Confirmation that the estimated actual values of demand response are applied.
2. The following requirements shall be defined by the OST in coordination with OSHE. Each Significant Grid User which is an Aggregator which participates in Demand Side Response shall communicate to OST and/or via its DSO to the OST at the day ahead and within a day at near real- time on behalf of all of its distribution connected demand sites as following:

a) Structural minimum and maximum Active Power available for Demand Side Response and the maximum and minimum duration of any potential activation of Demand Side Response in a specific geographical area defined by the OST and DSO;
b) forecast of unrestricted Active Power available for and any planned level of Demand Side Response in a specific geographical area defined by the OST and OSHE;
c) real-time Active and Reactive Power; and
d) confirmation of the estimated actual values of Demand Side Response applied.

Article 131. Responsibility of the Significant Grid Users

1. Each Significant Grid User with Connection Point directly to the Transmission System shall ensure that its facilities are compliant with the requirements of this Network Code, which are relevant for their connection and interaction with the Transmission System. This compliance shall be maintained throughout the lifetime of the facility.
2. Before initiating any modification, each Significant Grid User shall notify the OST or OSHE to which it has Connection Point, about any planned modification of its technical capabilities which could have an impact on its compliance with the requirements of this Network Code.
3. Each Significant Grid User shall notify the OST or OSHE to which it has Connection Point, about any operational disturbance on its facility which could have an impact on its compliance with the requirements of this Network Code as soon as possible and without any delay after its occurrence.
4. In order to allow the OST or DSO to evaluate and mitigate where necessary the risks to the Transmission System or Distribution Network, each Significant Grid User shall inform the OST or OSHE to which it has Connection Point of any foreseen tests or test schedules and procedures to verify compliance of a Significant Grid User's facility with the requirements of this Network Code.
5. OST or OSHE to which the Significant Grid User has Connection Point, shall approve the foreseen tests, or test schedules and procedures, prior to their launch.
6. The Significant Grid Users shall enable the participation of the OST or OSHE to which it has Connection Point in such tests. The OST or OSHE to which the Significant Grid User has Connection Point, shall have the right to record the performance of these facilities of the Significant Grid Users.
7. When the Significant Grid User has Connection Point to the OSHE and interacts only with the OSHE, in line with paragraph 1 to 6 of this article, the OST sh.a shall be entitled to request any compliance testing results, if this is relevant for Operational Security of the Transmission System.
8. Upon request from the OST or OSHE, the Significant Grid User shall carry out compliance tests and simulations at any time throughout the lifetime of the Significant Grid User's facility and in particular after any Fault, modification or replacement of any equipment which could have an impact on the Significant Grid User's facility compliance with the requirements of this Network Code, capability to achieve its Declared Availability or physically contracted provision of Ancillary Services.
9. The Aggregators, providing Demand Side Response directly to the OST, and Redispatching Aggregators and Providers of Active Power Reserve shall ensure that facilities in their portfolio are compliant with the requirements of this network code.

Article 132. Responsibilities of the OST and OSHE

1. OST has the sole responsibility for the Operational Security in its Responsibility Area in terms of:

a) utilizing the means within its own Responsibility Area including real-time operation, operational planning, development and deployment of tools and solutions for prevention and remedy of Disturbances;
b) utilizing the means provided through cooperation with other stakeholders including Redispatching or Countertrading and congestion management, operating reserves and other Ancillary Services;
c) respecting the rules of the ENTSO-E incidents classification scale
d) identifying, evaluating and implementing necessary enhancements of the means from this Article paragraph (1)(a) and (1)(b), or initiating amendments of this Network Code, required in order to maintain Operational Security
e) identifying, evaluating and implementing of necessary additional means to those from Article 132(1)(a), including development and implementation of new Ancillary Services and definition and implementation of new frameworks for data and information exchange, where cooperation with other stakeholders is needed and which are required in order to maintain Operational Security .

2. OST shall contribute to the annual reporting developed pursuant to the common incidents classification scale, adopted by ENTSO-E. The format and contents of this annual report, including geographical scope of the incidents reported, electrical interdependencies between the TSOs' Responsibility Areas and relevant historical information shall be approved by ACER. The annual report shall contain the Operational Security Performance Indicators on scale 1-3:

   a) number of tripped Transmission System elements per year;
   b) number of tripped Power Generation Facilities per year;
   c) energy of disconnected Demand Facilities per year;
   d) time duration of being in Operational States other than Normal State;
   e) time duration and number of events within which there was a lack of reserves identified;
   f) voltage deviation exceeding the voltage thresholds for Emergency State;
   g) frequency deviation per Synchronous Area;
   h) number of system-split separations or local blackouts; and
   i) number of blackouts involving two or more TSOs.

   The yearly report shall contain explanation of reasons for incidents at the Operational Security Ranking Scales 2 and 3 according to Article 132(3).
3. The Operational Security Ranking in the yearly report according to Article 132(1)(d) and Article 132(1)(e) shall be based on the following scales:

   a) Scale 1 where any primary failure may have high security influence and/or high market influence consequences or cause noticeable violation of standards for at least two Transmission System Operators;
   b) Scale 2 where any primary failure may lead to degradation of system adequacy with the necessity to activate at least one measure of the System Defense Plan;
   c) Scale 3 where there is Blackout in the Responsibility Area of more than one TSO;

4. OST or OSHE shall assess and where necessary request to witness the testing of the compliance of a Significant Grid User's facility with the requirements of this Network Code at any time throughout the lifetime of the Significant Grid Users' facility.
5. OST or OSHE to which the Significant Grid User has Connection Point retains the right to evaluate a Significant Grid User's compliance with the requirements from this Network Code, expected input or output, and contracted provision of Ancillary Services.

6. OST or OSHE to which the Significant Grid User has Connection Point, shall make publicly available the list of information and documents to be provided as well as the requirements to be fulfilled by the Significant Grid User in the framework of the compliance testing. Such list shall at least cover the following information, documents and requirements:
   a) all documentation and Equipment Certificates to be provided by the Significant Grid User
   b) details of the technical data of the Significant Grid User facility with relevance for the system operation;
   c) requirements for models for Dynamic Stability Assessment; and
   d) studies by the Significant Grid Users demonstrating expected outcome of the Dynamic Stability Assessment, where applicable.
7. OST and OSHE where applicable, shall make publicly available the allocation of responsibilities of the Significant Grid Users and of the OST or DSO for compliance testing and monitoring.
8. OST shall carry out the necessary analysis and planning using the Common Grid Model or a part of it to ensure that tests in its Responsibility Area are carried out in a manner that minimizes the impact on Operational Security and economic operation of the interconnected Transmission Systems and Significant Grid Users.
9. OST shall provide to the other TSOs at least that information on the test according to the multi-party agreements concluded in accordance with Chapter IV. The same information shall provide to the OSHE.
10. TSO shall elaborate a list of high priority Significant Grid Users which are Power Generating Facilities or Demand Facilities, in terms of the conditions for their disconnection and re-energizing.
11. OSHE is responsible for quality, reliability and security in its Distribution Network.

Article133. Common testing and incident analysis responsibilities

1. OST, DSO and Significant Grid User with Connection Point directly to the Transmission System shall monitor their areas of responsibility, may perform operational testing when required and shall participate in the analysis of events in order to:
   a) ensure correct functioning of elements of Transmission System, Distribution Network and the Significant Grid Users facilities;
   b) maintain and develop operational procedures;
   c) ensure the fulfilment of Ancillary Services;
   d) train staff;
   e) acquire information about system and equipment performance under any conditions, including:
      i. tests involving the controlled application of frequency or voltage variations aimed at gathering information on Transmission System behavior; and
      ii. tests of standard procedures in Emergency State and Restoration;
2. OST shall have Operational Security of its own Transmission System and Responsibility Area as its main concern during testing. Any test may be postponed or interrupted due to unplanned system conditions as assessed by the OST or due to safety of its personnel and equipment as assessed by the OSHE or Significant Grid User.
3. In the event of System State degradation in the Transmission System in which the testing is being performed, the OST of this Transmission System shall be entitled to interrupt the testing.

If OST or a Significant Grid User is conducting a test influencing another OST and the System State of the affected Transmission System changes to Alert State or Emergency State, if required the OST or Significant Grid User conducting the test shall, having been informed by its TSO, immediately cease the test.

4. OST, OSHE and Significant Grid Users shall exchange any relevant data, necessary to fully analyze both Local and Wide Area system incidents and facilitate system analysis.
5. OST shall ensure that the relevant results of tests carried out and the analysis of system incidents are:
   a) incorporated into the training and certification process;
   b) used as inputs to the ENTSO-E research and development process; and
   c) used to improve operational procedures including also procedures in Emergency State and Restoration.

Article 134. Design of the System Defense Plan

1. OST shall design a System Defense Plan in consultation with OSHE, Significant Grid Users and neighboring TSO's
2. When designing its System Defense Plan, OST sh.a shall take into account, at least:
   a) Operational Security Limits;
   b) behavior and capabilities of load and generation;
   c) Specific needs of high priority Significant Grid Users listed pursuant to Article132 (10) of the Code.
   d) characteristics of its Network and OSHE Networks.
3. In the design of System Defense Plan, OST shall respect the following principles:
   a) the impact for System Users is minimal;
   b) the measures are economically efficient;
   c) only the necessary measures are activated; and
   d) the measures do not endanger the Operational Security of Transmission System or of the interconnected Transmission Systems.
4. The system defense Plan shall include at least:
   a) System Protection Schemes including at least:
      i. automatic under-Frequency control scheme;
      ii. automatic over-Frequency control scheme; and
      iii. automatic scheme against Voltage collapse.
   b) System Defense plan procedures including at least:
      i. Frequency Deviation management procedure;
      ii. Voltage Deviation management procedure
      iii. Power flows management procedure;
      iv. assistance for Active Power procedure; and
      v. manual Demand disconnection procedure
5. OST shall define at least in its System Defense Plan procedures:
   a) the conditions under which the procedure is activated, according to Article 135;
   b) the relevant set of measures;
   c) System Defense Plan instructions to be issued by the TSO;
6. OST shall notify the regulatory authority at least the following elements of System Defense Plan:

a) objectives the System Defense Plan intend to achieve, including the phenomena to be managed or the situation to be solved;
b) conditions triggering the measures of the System Defense Plan;
c) general principle of each measure, explaining how each measure contributes to the objectives of the System Defense and that will implement these measures; and
d) Deadlines for implementation of the measures.

7. In the design of System Defense Plan, OST shall:

a) list the measures to be implemented on its installations;
b) list the measures to be implemented by OSHE
c) identify Significant Grid Users that have to implement measures on their installations and list the measures to be implemented by these Significant Grid Users;
d) list the measures to be implemented by relevant grid users; and
e) identify the deadlines for implementation for each measures listed.

Article 135. Implementation of the System Defense Plan

1. OST shall implement and maintain the measures of its System Defense Plan which shall be implemented on the Transmission System.
2. OST shall notify:

a) OSHE on the measures, including the deadlines for implementation, which are to be implemented on:
   i. their installations pursuant to Article 134(7); and/or
   ii. the installations of Significant Grid Users identified pursuant to Article 134(7) connected to their Distribution Systems; and/or
   iii. Significant Grid Users identified pursuant to Article 134(7) for measures that will apply to their installations, including implementation deadlines.

3. OSHE shall notify the Significant Grid Users, for the measures of the System Defense Plan they have to implement on their installations, including the deadlines for implementation, unless the OST already notified them pursuant Transmission Code.
4. OSHE and Significant Grid User shall:

a) implement the measures notified to it and notify for this the OST ; and
b) maintain the measures implemented on its installations.

Article 136. Activation of the System Defense Plan

1. OST shall activate procedures of its System Defense Plan in coordination with OSHE and Significant Grid Users identified pursuant with Article 134(7).
2. In addition to the automatically activated measures of the System defense plan, OST shall activate the procedure of System Defense Plan when:

a) the system is in Emergency State due to at least one deviation from the Operational Security Limits and times according to Article 109(1) of Grid Code and no Remedial Action is available to restore the system to Normal State; or
b) according to Operational Security Analysis, the Operational Security of the Transmission System requires the activation of a measure of the System Defense Plan in addition to available Remedial Actions.

3. OST shall be coordinated with other TSOs, affected by activation of System Defense Plan measures

Article 137. Restoration plan

1. Restoration plan shall be designated by OST in consultation with all transmission Grid Users.
2. Restoration plan shall be implemented by the OST and all Transmission Network Users for partial or total black out
3. The system operator is responsible for following the procedures, in a timely manner pursuant the restoration plan for the partial or total black out of Power System. These procedures and instructions shall be documented in the operational service book and shall be reflected in a special charge sheet.
4. OST requires the integrated coordination and induced of the Transmission Network Users in the preparation of the Restoration Plan.
5. Transmission Network Users Operational staff, follow the instructions according to the restoration procedures, issued by the system operator.
6. System operator is responsible for the general management of the restoration process in Power System, through coordination with all Transmission Network users and regional coordination centers of ENTSO-E, in accordance with the requirements of the Network Code.
7. Power Generating Modules are responsible for starting restoration procedures (black start) and after instructions issued by the system operator, synchronize their generating units.

Article 138. Restoration Procedures

1. Existing conditions of an event, such as the availability of generation units, transmission lines, substations , as well as the load on the whole, shall determine the process to be implemented in case of total or partial black out of the Power System.
2. The National Dispatch Center and Regional Dispatch Centers shall coordinate their actions in order to define the extension of event and the type of system black out (partial or total).
3. System Operator shall instruct all Transmission Network Users on the situation and follow a strategy based on the situation after the event.
4. Transmission Network Users shall follow and apply guidelines and Dispatch Center orders. Orders are transmitted through telecommunication channels dedicated only for operative actions.

Article 139. Control, Supervision, Testing

1. Control, supervision and testing should be performed according to procedures for:
    a) Control and supervision of all transmission network users (Power generating units, Distribution System Operator and Clients connected to the transmission system) to verify the operating parameters.
    b) Testing of generating units to verify the compliance of parameters and their technological systems, in accordance with their statements and data.
    c) Testing of systems / facilities of the Distribution System Operator and verify the compliance of parameters and their technological systems, in accordance with their statements and data.
2. The purpose of this article is to examine whether:
    a) Power generation units operate according to stated technical parameters and their willingness.
    b) Systems/objects of Distribution System Operator and Clients operate according to stated technical parameters and their willingness
3. Actions of control, supervision and testing are performed by OST when:

a) Power generation units operate on different parameters from those stated;
b) Systems/facilities of Distribution System Operator and Clients operate on different parameters from those stated;
c) A Transmission Network User do not follows the instructions of System Operator or fails to apply its orders.

Article140. Capabilities Testing to Comply with OST Requirements

1. Testing of active power generation and absorbing capacity :

    a) Once per year, OST may require testing of th power generation units, to verify if they respect the generation/absorbing capacity of reactive power.
    b) Testing is required by OST and the time period is approved by the System Operator;
    c) OST should inform the power generating unit on the scope of the test, 48 hours in advance.
    d) If the power generation Facility test indicates that tested parameters do not meet the stated parameters, the Power generator module should submit within 5 days to OST a detailed report that specifies the reasons of and actions to be taken.
    e) If deviations are large and incorrigible, the review of agreement between OST and Power generator.

2. Testing of Primary and Secondary Reserve (FCR &FRR) capabilities:

    a) The testing of capabilities to make available Primary and Secondary Reserve by OST is obligatory.(FCR &FRR)
    b) This test is periodically performed by the System Operator through SCADA in correlation with control and supervision activity of Generation Units operation.
    c) If the Power generation unit test indicates that tested parameters do not meet the stated parameters, the Generator should submit within 5 days to OST a detailed report that specifies the reasons of and actions to be taken.
    d) If deviations are large and incorrigible, the review of agreement between OST and Power Generator is proposed.

Article141. Testing of Generation Unit Starting Capacity

1. Testing of Power Generating Unit starting capacity once per year is binding for each power generation Unit in order to evidence whether the Generation Unit comply with the rapid starting capacity according to stated parameters.
2. Testing is required by OST only during the time in which power generating unit is stated on standby.
3. OST should inform the power generator on the scope of testing, 48 hours in advance.
4. If the test of power generating units indicates that tested parameters do not meet the stated parameters, the power generator should submit within 5 days a detailed report to OST that specifies the reasons of and actions to be taken.
5. If deviations are too large and incorrigible, the review of agreement between OST and the Generator is proposed.

Article 142. Testing of Capacities to Participate in Power System Restoration

1. OST shall require testing of power generating units for System Restoration after a black out. The test is performed once per year in order to evidence that the power generating facility has the starting capability in conformity with System Restoration Plan requirements.
2. Testing can be performed in one of the following options:

a) restarting of generation unit from an independent source (for ex. diesel group)
b) restarting of power generating unit from auxiliary supply(house load)

3. OST should inform the power generating module on the scope of tests 7 calendar days in advance.
4. If the test of power generating unit indicates that tested parameters do not meet the stated parameters, the power generating module should submit within 5 days to OST a detailed report that specifies the reasons and actions to be taken.

5. If deviations are too large and incorrigible, the review of agreement between OST and Generator is proposed.

CHAPTER VI

Network Code on Load-Frequency Control and Reserves

Article 143. Subject matter and Scope

1. Network Code on Load-Frequency Control and Reserves provides security operations related to the frequency stability of the system, providing:
   a) harmonization of system frequency quality objectives;
   b) the harmonization of processes of control and operational procedures;
   c) the harmonization of minimum technical requirements for organization of reserves' provisions by OST;
   d) harmonization of minimum technical requirements for units and groups that provide reserves; and
   e) harmonization of procedures relating to cross-border exchanges, sharing and activation of active power reserves within the synchronous area, to improve the overall operating efficiency.
2. This Code sets out minimum requirements and principles for power-frequency control and reserves applicable to OST sh.a, OSHE and Providers Reserve.
3. This Code aims to:
   a) Performing and maintaining a satisfactory level of quality and efficient use of frequency system and resources;
   b) definition of common requirements and principles for FCR, FRR and RR;
   c) defining common requirements for cross-border exchange, sharing, activation and reserves dimensioning.
4. No action in fulfillment of this Code shall prevent the implementation of new applications, in accordance with industry best practices.

Article 144. Synchronous area operational agreement

1. OST will be a signatory of Operational Agreement between European TSOs of continental synchronous area.

Article 145. LFC block operational agreement

1. At present, OST is control area and control block manager. With the expected regional developments, OST will be part of the Operational Agreement between TSOs of south-east Europe initiatives, for synchronous block areas.

Article 146. Imbalance netting agreement

1. After fulfilling the conditions for participation, OST shall be party of imbalance netting agreement, which shall be signed with neighboring TSO's, pursuant with terms and conditions that defines roles and responsibilities of any participating TSO.

Article 147. Agreements for share and/or activation of reserves

1. After fulfilling the appropriate conditions for share or activation of FRR and/or RR reserves, OST shall conclude an agreement with participating TSOs, in this cross-border activity for sharing or exchanging of reserves, in accordance with the terms that will define the roles and responsibilities of each participating TSO.

Article 148. Frequency quality target parameters

1. The Frequency Quality Defining Parameters shall be:
    a) the Nominal Frequency for all Synchronous Areas;
    b) the Standard Frequency Range for all Synchronous Areas;
    c) the Maximum Instantaneous Frequency Deviation
    d) the Maximum Steady-State Frequency
    e) the Time to Restore Frequency
    f) the Alert State Trigger Time
2. The Nominal Frequency shall be 50Hz
3. The values of the Frequency Quality Defining Parameters are given in Table 1.

Standard Frequency Range	Maximum Instantaneous Frequency Deviation	Maximum Steady-state Frequency Deviation	Frequency Restoration Range	Alert state trigger time
±50 mHz	800 mHz	200 mHz	15 min	5 min

Table 1: Frequency Quality Defining Parameters of the Synchronous Areas

4. The Frequency Quality Target parameter shall be the maximum number of minutes out of standard frequency range during a year. For European Continental Synchronous Area, its default value (which must not be exceeded) is 15,000 minutes.
5. The Frequency Quality Defining Parameters (3) and the Frequency Quality Target Parameter (4) shall have the default values unless all TSOs of a Synchronous Area agree on modified values.

Article 149. Criteria application process and frequency quality evaluation criteria

1. The Criteria Application Process shall comprise:
    a) the collection of Frequency Quality Evaluation Data; and

   b) the calculation of Frequency Quality Evaluation Criteria.
2. The Frequency Quality Evaluation Criteria shall comprise:
   a) for the Synchronous Area for operation in Normal State, for a 1-month period for the Instantaneous Frequency Data (ACE) of LFC block for time periods equal with restoration frequency time range (15min.)
      i. the mean value;
      ii. the standard deviation;
      iii. the 1- ,5-,10-, 90-,95- and 99-percentile;
      iv. the total time in which the absolute value of the Instantaneous Frequency Deviation was larger than 60 % of RR Capacity reserves .

Article 150. Data collection and delivery process

1. The Data Collection and Delivery Process shall comprise the following:
   a) measurements of the System Frequency;
   b) calculation of the Frequency Quality Evaluation Data; and
   c) delivery of the Frequency Quality Evaluation Data for the Criteria Application Process in coordinating monitoring center of synchronous area.
2. The Frequency Quality Evaluation Data shall be:
   a) the Instantaneous Frequency Data; and
   b) the Instantaneous Frequency Deviation Data; and
   c) Instantaneous FRCE Data in MW;
3. The measurement accuracy of the Instantaneous Frequency Data shall be 1 mHz.
4. OST as Synchronous Area Monitor of its LFC block, shall send to continental European synchronous area monitor, data assessment of frequency quality parameters, in the format and frequency required by them.

Article 151. Information on load and generation behavior

1. In accordance with Article 117(3) and Article 117(4) of this Code, OST shall have the right to request the information necessary from Significant Grid Users to monitor the load and generation behavior related to imbalances. This information may include:
   a) the time-stamped Active Power Setpoint for real-time and future operation; and
   b) the time-stamped total Active Power output.

Article 152. BASIC STRUCTURE

1. All TSOs of a Synchronous Area shall define in the Synchronous Area Operational Agreement the Load-Frequency-Control Structure for the Synchronous Area. Each TSO is responsible for implementing and operating according to the Load-Frequency Control Structure.
2. The Load-Frequency Control Structure shall include:
   a) a Process Activation Structure
   b) a Process Responsibility Structure

Article 153. Process activation structure

1. The Process Activation Structure shall include:
   a) a FCP according to Article 155; and
   b) a FRP according to Article 156.
2. The Process Activation Structure may include:
   a) a replacement reserve process (RRP) according to Article 157;
   b) an Imbalance Netting Process according to Article 158;
   c) a Cross-Border FRR Activation Process according to Article 159;

d) a Cross-Border RR Activation Process according to Article 160; and
e) a Time Control Process according to Article 181.

Article 154. PROCESS RESPONSIBILITY STRUCTURE

1. When defining the Process Responsibility Structure, all TSOs of a Synchronous Area shall take into account the following criteria:
   a) size and the total Inertia and Synthetic Inertia of the Synchronous Area;
   b) grid structure and/or network topology; and
   c) load, generation and HVDC behavior.
2. OST shall continuously calculate and monitor the real-time Active Power interchange of its Monitoring Area.
3. OST for its LFC Block/Area shall:
   a) continuously monitor the FRCE of the LFC Area;
   b) implement and operate a FRP and FRP for the LFC Area;
   c) make best endeavors to fulfil the FRCE Target Parameters of the LFC Area as defined in Operational Agreement between all TSO's of synchronous area.
   d) have the right to implement one or several of the processes referred to in Article 153(2).
   e) meet dimensioning rules for FCR, FRR and RR provided in article 165,168 and 170.
4. OST have the right to establish or to be included in a LFC block, with one or several Neighboring TSO's, implementing all requirements of this Code for LFC Block.

Article 155. Frequency containment process (FCP)

1. The control target of FCP is to stabilize the System Frequency by activation of FCR.
2. The overall characteristic for FCR activation in a Synchronous Area shall reflect a monotonically decrease of the FCR activation as a function of the Frequency Deviation.

Article 156. Frequency restoration process (FRP)

1. The control target of the FRP is to:
   a) regulate the FRCE towards zero within the Time to Restore Frequency; and
   b) to progressively replace the activated FCR by activation of FRR;
2. FRCE is:
   a) the Area Control Error (ACE) of a LFC Area where there are more than one LFC Area in a Synchronous Area; or
   b) the Frequency Deviation where one LFC Area corresponds to the LFC Block and the Synchronous Area.
3. ACE of a LFC Area shall be calculated according the formula: $ACE = \Delta P + K*\Delta F$ whereas ΔP represents the difference of active power measured in interconnectors (real and virtual) with scheduled active power control program (commercial program + compensation program); K is the factor that represents the slope of active power/frequency characteristic of the relevant area, and ΔF represents the difference between instantaneous frequency with standard frequency or with secondary frequency regulator .
4. The Setpoint value for automated FRR activation shall be calculated by a single frequency restoration controller operated by OST within its LFC Area. The frequency restoration controller shall:
   a) be an automatic control device designed to reduce the ACE to zero;
   b) be operated in a closed-loop manner with FRCE as input and Setpoint value for FRR activation as output;
   c) have proportional-integral behavior; and

d) have a control algorithm which prevents the integral term of a proportional-integral controller from accumulating the control error and overshooting.
5. The Setpoint value for manual FRR activation shall be left to the discretion of the OST for its LFC Area.

Article157. Reserve replacement process (RRP) (Tertiary regulation)

1. The control target of the RRP is to fulfil the following goals:
   a) progressively restore the activated FRR;
   b) support FRR activation; and
2. The Setpoint value for RR activation shall be determined by TSO for its LFC Area.

Article 158. Imbalance netting process

1. The control target of the Imbalance Netting Process is to reduce the amount of simultaneous counteracting FRR activation of different participating LFC Areas by Imbalance Netting Power Interchange. OST shall have the right to implement the Imbalance Netting Process for LFC Areas within the same LFC Block or between different LFC Blocks.
2. The Imbalance Netting Process shall be implemented in such a way that it does not affect
   a) the stability of the FCP of Synchronous Areas
   b) the stability of the FRP and the RRP of each LFC Area operated by participating or Affected TSOs; and
   c) Operational Security

Article159. Cross-border FRR activation process

1. The control target of the Cross-Border FRR Activation Process is to enable a TSO to perform the FRP by Frequency Restoration Power Interchange between LFC Areas. OST shall have the right to implement the Cross-Border FRR Activation Process for LFC Areas within the same LFC Block, between different LFC Blocks by concluding a Cross-Border FRR Activation Agreement.
2. The Cross-Border FRR Activation Process shall be implemented in such a way that it does not affect:
   a) In the stability of the FCP of the Synchronous Area
   b) the stability of the FRP and the RRP of each LFC Area operated by participating or Affected TSO's; and
   c) Operational Security

Article 160. Cross-border RR activation process

1. The control target of the Cross-Border RR Activation Process is to enable a TSO to perform the RRP through Replacement Power Interchange between LFC Areas. TSO sh.a shall have the right to implement the Cross-Border RR Activation Process for LFC Areas within the same LFC Block, between different LFC Blocks or between different Synchronous Areas by concluding a Cross- Border RR Activation Agreement.
2. The Cross-Border RR Activation Process shall be implemented in such a way that it does not affect
   a) the stability of the FCP of the Synchronous Area
   b) the stability of the FRP and the RRP of each LFC Area operated by participating or Affected TSOs; and
   c) Operational Security

Article 161. General requirements for cross-border control processes

1. All TSOs participating in an Exchange or Sharing of FRR/RR shall implement a Cross-Border RR Activation Process.
2. OST shall be part of a Synchronous Area Operational Agreement in which are defined the roles and the responsibilities of the TSOs implementing an Imbalance Netting Process, a Cross-Border FRR Activation Process or a Cross-Border RR Activation Process between LFC Areas of different LFC Blocks.
3. All TSOs participating in the same Process shall of : (i)imbalance netting process,(ii)Cross-border of FRR and/or RR shall define in an operational Agreement, the roles and responsibilities of the TSOs including but not limited to:
   a) the provision of all input data necessary for
      i. calculation of power interchange with respect to the Operational Security Limits;
      ii. real-time Operational Security Analysis by participating and Affected TSOs;
   b) the responsibility to calculate the power interchange; and
   c) the implementation of operational procedures to ensure Operational Security.

Article 162. TSO's notification

1. All TSOs willing to implement an Imbalance Netting Process, a Cross-Border FRR Activation, a Cross-Border RR Activation Process, Exchange of Reserves or Sharing of Reserves shall send a notification to all TSOs of the Synchronous Area three months in advance. The notification shall include:
   a) involved TSO's
   b) expected amount of power interchange due to the Imbalance Netting Process, Cross-Border FRR Activation Process or Cross-Border RR Activation Process;
   c) reserve type and amount of Exchange or Sharing of Reserves; and
   d) time frame of Exchange or Sharing of Reserves.
2. Where an Imbalance Netting Process, a Cross-Border FRR Activation Process or a Cross-Border RR Activation Process is implemented for LFC Areas which are not parts of the same LFC Block, each TSO of the involved Synchronous Areas shall have the right to declare itself to all TSOs of the Synchronous Area as an Affected TSO based on Operational Security Analysis within one month after notification.

Article 163. Infrastructure

1. OST in coordination with neighboring TSO's shall consider the technical infrastructure necessary to implement and operate one or more processes listed in Article 153 as critical according to Chapter V of this Code.
2. In Operational Synchronous Area Agreement, all TSOs shall define minimum requirements for availability, reliability and redundancy of the technical infrastructure referred to in paragraph (1) including but not limited to:
   a) precision, resolution, availability and redundancy of Active Power flow and Virtual Tie-Line measurements;
   b) availability and redundancy of digital control systems;
   c) availability and redundancy of communication infrastructure; and
   d) communication protocols.
3. For LFC Area, OST shall:
   a) ensure a sufficient quality and availability of the ACE deviation calculation;
   b) perform real-time quality monitoring of the ACE calculation;
   c) take action in case of FRCE miscalculation; and,
   d) perform an ex-post quality monitoring of the ACE calculation by comparing FRCE to reference values at least on an annual basis.

Article164. System states related to the system frequency

1. OST shall establish a real-time data exchange with all TSO's of synchronous Area, through Electronic Highway of ENTSO-e pursuant with Article 119 of the Code to:
   a) the System State of the Transmission System as defined in article 109.
   b) Real time data measures of ACE.
2. The Synchronous Area Monitor shall determine the System State with regard to the System Frequency in reference to Article 109 according to the System Frequency limits defined in (3) and (4).
3. The System Frequency limits for Normal State are fulfilled when:
   a) the steady state System Frequency Deviation is within the Standard Frequency Range; or
   b) the steady state System Frequency Deviation is not larger than 50 % of the Maximum Steady State Frequency Deviation for a time period not longer than the Time to Restore Frequency; or
   c) the steady state System Frequency Deviation is not larger than the Maximum Steady State Frequency Deviation for a time period not longer than the Alert State Trigger Time.
4. The System Frequency limits for Alert State are fulfilled when:
   a) the absolute value of the steady state System Frequency Deviation is not larger than the Maximum Steady State Frequency Deviation; and
   b) the System Frequency limits for Normal State are not fulfilled
5. The Synchronous Area Monitor shall ensure that all TSOs of all Synchronous Areas are informed in case the System Frequency Deviation fulfils one of the criteria for the Alert State.
6. The OST shall define in the Synchronous Area Operational Agreement common rules for the operation of Load-Frequency Control in Normal State and Alert State.
7. The OST shall reduce the ACE of its LFC Block by activation of Active Power Reserves and if necessary by application of the actions as defined in paragraph (8).
8. OST shall define operational procedures in cases of exhausted FRR and RR reserves, according to which OST shall have the right to require changes in the Active Power production or consumption of Power Generating Modules and Demand Units, OST shall make best endeavors to avoid ACE deviations greater than the time for frequency restoration.

Article165.FCR dimensioning

1. All TSOs of a Synchronous Area shall determine the FCR Capacity required for the Synchronous Area and the shares of FCR required for each TSO as the Initial FCR Obligation
2. All TSOs of a Synchronous Area shall define in the Synchronous Area Operational Agreement dimensioning rules respecting the following criteria:
   a) the FCR Capacity required for the Synchronous Area shall at least cover the Reference Incident of the Synchronous Area, based on a deterministic analysis and respecting the Frequency Quality Defining Parameters; and
   b) All TSOs of a Synchronous Area shall define a dimensioning approach for FCR on the basis of the principle of covering remaining imbalances in the Synchronous Area that are likely to happen according to a probability of once in 20 years.
3. The size of the Reference Incident shall be defined, respecting the following conditions:
   a) the Reference Incident shall be the absolute value of the largest imbalance that may result from an instantaneous change of Active Power of one or two power generating modules; or
   b) One or two HVDC Interconnectors connected to the same electrical node; or

c) the maximum instantaneous loss of Active Power consumption due to the tripping of one or two Connections Points;

4. The shares of the FCR Capacity required for each TSO as Initial FCR Obligation shall be based on the sum of the net generation and consumption of its area divided by the sum of net generation and consumption of the Synchronous Area over a period of one year.

Article 166. FCR technical minimum requirements

1. OST shall ensure that the FCR corresponds to the following properties listed for its Synchronous Area applying to all FCR Providing Units and FCR Providing Groups consistent with the following values :

Minimum accuracy of frequency measurement	10 mHz or the industrial standard if better
Maximum combined effect of inherent Frequency Response Insensitivity and possible intentional Frequency Response Dead band of the governor of the FCR Providing Units	10 mHz
FCR Full Activation Time	30 sec
FCR Full Activation Frequency Deviation.	±200 mHz

2. OST shall have the right to define common additional properties of the FCR required to ensure Operational Security in the Synchronous Area by means of a set of technical parameters and within the ranges described in requirements for power generating modules and requirements on demand connection. FCR Providers shall ensure that monitoring of FCR Activation for their units, is possible.
3. Each FCR Providing Unit shall only have one Reserve Connecting TSO.
4. OST shall implement a FCR Prequalification to assess the fulfilment of the technical and Availability Requirements by potential FCR Providing Units This process shall include at least a reassessment in case requirements or equipment change and a periodical reassessment within the time frame of at least five years
5. OST shall provide that FCR activation is in accordance with the requirements of the synchronous area.
6. OST shall monitor its contribution to the FCP and its FCR activation with respect to its FCR Obligation including FCR Providing Units and FCR Providing Groups. Each FCR Provider shall make available to the Reserve Connecting TSO , at least the following information:
   a) time-stamped status indicating if FCR is on or off;
   b) time-stamped Active Power data needed to verify FCR activation. This data shall include, but is not limited to time-stamped instantaneous Active Power

   Droop of the governor for all types of Power generation Modules. At the request of the Reserve Connecting TSO, a FCR Provider has to make this information available in real time with a time resolution of at least 10 seconds.
   At the request of the Reserve Connecting TSO, a FCR Provider has to make available data for technical installations which are part of the same FCR Providing Unit in case it is necessary for clear verification of activation of FCR.

Article 167. FCR Provision

1. OST shall ensure the availability of at least its FCR Obligation agreed upon in accordance with Article 165(4), and 172.

2. The TSOs of a Synchronous Area shall determine at least on an annual basis the size of the K- Factor of the Synchronous Area taking into account factors including, but not limited to:
   a) The FCR Capacity divided by the Maximum Steady-State Frequency Deviation;
   b) the auto-control of generation; and
3. the self-regulation of load taking into account the contribution according to the Network Code on demand Connection The shares of the K-Factor for each OST shall be based on:
   a) its Initial FCR Obligation divided by the FCR Capacity of Synchronous area; and
   b) the amount of FCR Capacity from FCR Providing Units or FCR Providing Groups with a Connection Point inside the LFC Area
4. A FCR Provider shall guarantee the continuous availability of FCR with the exception of a Forced Outage of a FCR Providing Unit during the time period in which it is obliged to provide FCR.
   Each FCR Provider shall inform OST about any changes in actual availability of its FCR Providing Unit or its FCR Providing Group or a part of its
5. Each OST shall ensure, or shall require from its FCR Providers to ensure that loss of an unit providing FCR does not endanger system security by:
   a) limiting the share of the FCR provided per FCR Providing Unit to 5 % of the FCR Capacity required for the Synchronous Area ; and
   b) replacing the FCR which is made unavailable due to an Forced Outage as soon as technically possible and according to the conditions that shall be defined by TSO.
6. A FCR Providing Unit :
   a) with an energy reservoir that does not limit the FCR providing capability shall activate its FCR as long as the Frequency Deviation persists.
   b) with an energy reservoir that limits the FCR providing capability shall activate its FCR as long as the Frequency Deviation persists unless its energy reservoir is exhausted in either direction

   a FCR Providing Unit with an energy reservoir that limits the FCR providing capability shall be able to fully activate its FCR continuously for a time period of not less than 30 minutes and shall take appropriate measures to ensure recovery of energy reservoirs as soon as possible but at the latest within 2 hours.

Article 168. FRR Dimensioning

1. The FRR Dimensioning Rules shall comprise at least the following requirements:
   a) TSO shall determine the required FRR Capacity of the LFC Block based on consecutive historical records at least comprising historical LFC Block Imbalance values. The considered time period of these records shall be representative and include at least one full year period ending not earlier than 6 months prior to the calculation;
   b) OST shall determine the FRR Capacity of the LFC Block such that it is sufficient to respect the ACE deviation for time period considered historical period based at least on a probabilistic methodology. In this methodology restrictions due to agreements for the Sharing or Exchange of Reserves due to possible violations of Operational Security and the FRR Availability Requirements shall be taken into account.
   c) OST shall determine the ratio of Automatic aFRR Capacity, manual mFRR Capacity, the Automatic FRR Full Activation Time and manual FRR Full Activation Time such that requirement (b) can be fulfilled. For this the Automatic FRR Full Activation Time of a LFC Block and the Manual FRR Full Activation Time of the LFC Block shall at most be the Time to Restore Frequency.

d) OST shall determine the size of the Dimensioning Incident which shall be the largest imbalance that may result from an instantaneous change of active power of a single Power Generating Module, single Demand Facility, and single HVDC interconnector or from a tripping of an AC-Line within the LFC Block.
e) OST shall determine the positive FRR Capacity such that it is not smaller than the positive Dimensioning Incident of the LFC Block; and the negative FRR Capacity such that it is not smaller than the negative Dimensioning Incident of the LFC Block;
f) TSO of a LFC Block shall determine the FRR Capacity and possible geographical limitations for its distribution within the LFC Block and possible geographical limitations for any Exchange of Reserves or Sharing of Reserves with other LFC Blocks to respect the Operational Security;
g) OST shall ensure that the positive/negative FRR Capacity or a combination of FRR and RR Capacity is sufficient to cover the positive LFC Block Imbalances in at least 99 % of the time based on the historical record as defined in (a);
h) OST will be allowed to reduce the positive/negative FRR Capacity of the LFC Block, resulting from the FRR Dimensioning Process, by concluding a FRR Sharing Agreement with other LFC Blocks in accordance with the provisions of article 172 to 180 of this Code. The reduction of the positive FRR Capacity of a LFC Block is:
   i. limited to the difference, if positive, between the size of the positive Dimensioning Incident and the FRR Capacity required to cover the positive LFC Block imbalances in 99 % of time based on historical records as defined in (a); and
   ii. shall never exceed 30 % of the size of the positive/negative Dimensioning Incident.

2. Where the LFC Block comprises to more than one TSO, than OST shall define in the LFC Block Operational Agreement the specific allocation of responsibilities between TSOs of the LFC Areas for the implementation of the obligations established in the upper point.

Article 169. FRR Technical minimum requirements

1. The FRR Technical Minimum Requirements shall be:
   a) each FRR Providing Unit and each FRR Providing Group shall be connected to only one Reserve Connecting TSO;
   b) a FRR Providing Unit shall activate FRR according to the Setpoint received from the Reserve Instructing TSO;
   c) the Reserve Instructing OST shall be the Reserve Connecting TSO or a TSO that shall be defined by the Reserve Connecting TSO in an FRR Exchange Agreement according to the provisions of Article 174.
   d) a FRR Providing Unit for Automatic FRR shall have an Automatic FRR Activation Delay of at most 30 seconds;
   e) a FRR Provider shall ensure that monitoring of the FRR activation of any FRR Providing Units is possible. For this the FRR Provider shall be able to supply to the Reserve Connecting TSO and the Reserve Instructing TSO real-time measurements of the Connection Point agreed with the Reserve Connecting TSO of:
      i. time-stamped scheduled Active Power output;
      ii. time-stamped instantaneous Active Power
   f) a FRR Providing Unit for Automatic FRR shall be able to activate its complete FRR Capacity within the Automatic /Manual FRR Full Activation Time;
   g) a FRR Provider shall fulfil the FRR Availability Requirements;
2. The Reserve Connecting TSO shall define technical requirements for the connection of FRR Providing Units and FRR Providing Groups to ensure that the delivery of FRR is possible in a safe and secure way.

3. OST shall implement a FRR Prequalification to assess the fulfilment the FRR Technical Minimum Requirements according to (1), the FRR Availability Requirements and the connection requirements according to (2) by potential FRR Providing Units. This process shall include at least a reassessment in case requirements or equipment change and a periodical reassessment within the time frame of at least five years.
4. Any FRR Provider shall:
   a) ensure that its FRR Providing Units and FRR Providing Groups fulfil the FRR Technical Minimum Requirements, the FRR Availability Requirements and connection requirements according to upper paragraphs.
   b) inform OST about a reduction of the actual availability of its FRR Providing Unit or its FRR Providing Group without undue delay.
5. OST shall ensure that for its FRR Providing Units, the fulfilment of the FRR Technical Minimum Requirements, the FRR Availability Requirements and connection requirements according are monitored.

Article 170. RR Dimensioning

1. The RR Dimensioning Rules shall comprise at least the following requirements
   a) sufficient positive/negative RR Capacity to restore the required amount of positive /negative FRR
   b) sufficient RR Capacity, if taken into account to dimension the FRR Capacity to respect the ACE Quality Target for the considered period of time, based on theoretical considerations; and
   c) respect the Operational Security within a LFC Block to determine RR Capacity.
2. TSO is allowed to reduce the positive/negative RR Capacity of the LFC Block, resulting from the RR Dimensioning Process, by concluding a RR Sharing Agreement for this positive RR Capacity with other LFC Blocks in accordance with the provisions of Articles 171 to 180. OST shall reduce the positive/negative RR Capacity in order to:
   a) to guarantee that it can still meet its ACE Quality Targets
   b) to ensure that Operational Security is not endangered; and
   c) to ensure that the reduction of the positive/negative RR Capacity shall never exceed the remaining positive/negative RR Capacity of the LFC Block.
3. Where a LFC Block is operated by more than one TSO, all TSOs of that LFC Block shall define in the LFC Block Operational Agreement the specific allocation of responsibilities between TSOs of different LFC Areas for the implementation of the obligations defined in the upper paragraphs

Article 171. RR Technical minimum requirements

1. The RR Technical Minimum Requirements for RR Providing Units and RR Providing Groups shall be:
   a) each RR Providing Unit and each RR Providing Group shall be connected to only one Reserve Connecting TSO;
   b) a RR Providing Unit or RR Providing Group shall activate RR according to the Set Point received from the Reserve Instructing TSO;
   c) the Reserve Instructing OST shall be the Reserve Connecting TSO or a TSO that shall be defined by the Reserve Connecting TSO RR Exchange Agreement according to the provisions of Article 174;
   d) a RR Providing Unit or RR Providing Group shall activate its complete RR Capacity within the activation time defined by the Instructing TSO;

e) a RR Providing Unit or RR Providing Group shall de-activate RR according to the Set Point received from the Reserve Instructing TSO;
f) a RR Provider shall ensure that monitoring of the RR activation of the RR Providing Units within a Reserve Providing Group is possible. For this, the RR Provider shall be able to supply to the Reserve Connecting TSO and the Reserve Instructing TSO real-time measurements of the Connection Point or another point of interaction agreed with the Reserve Connecting TSO of:
   i. time-stamped scheduled Active Power output; and
   ii. time-stamped instantaneous Active Power
g) a RR Providing Unit or RR Providing Group shall fulfil the RR Availability Requirements.

2. The Reserve Connecting TSO shall define technical requirements for the connection of RR Providing Units and RR Providing Groups to ensure that the delivery of RR is possible in a safe and secure way.
3. OST shall implement a RR Prequalification to assess the fulfilment of the technical and Availability Requirements by possible RR Providing Units and RR Providing Groups This process shall include at least a reassessment in case requirements or equipment change and a periodical reassessment within the time frame of at least five years.
4. Any RR Provider shall:
   a) ensure that its RR Providing Unit or RR Providing Groups fulfil the RR technical minimum requirements and the RR Availability Requirements; and
   b) Inform OST about a reduction of the actual availability or a Forced Outage of its RR Providing Unit or RR Providing Group without undue delay.
5. OST shall ensure that, its RR Provider is monitored related with the fulfilment of the RR Technical Requirements, RR Availability Requirements and the connection requirements.

Article 172. Exchange of FCR within a synchronous area

1. The Exchange of FCR within a Synchronous Area is allowed in accordance with the provisions and limits of this article. The Exchange of FCR invokes a transfer of FCR Obligation from the Reserve Receiving TSO to the Reserve Connecting TSO for the considered FCR Capacity.
2. All TSOs involved in the Exchange of FCR within a Synchronous Area shall ensure to respect the limits and requirements for the Exchange of FCR within the Synchronous Area as defined in the Table below:

Synchronous Area	**Exchange of FCR allowed between:**	**Limits for the Exchange of FCR**
Synchronous Area CE	TSOs of Adjacent LFC Blocks	-the TSOs of a LFC Block shall ensure that at least 30 % of their total combined Initial FCR Obligations, according to Article 165(1), is physically provided inside their LFC Block; and - the amount of FCR Capacity, physically located in an LFC Block as a result of the Exchange of FCR with other LFC Blocks, shall be limited to the maximum of: ○ 30 % of the total combined Initial FCR Obligations, according to Article 165(1), of the TSOs of the LFC Block to which the FCR Capacity is physically connected; and

		o 100 MW of FCR Capacity.
	TSOs of the same LFC Block	- the TSOs of the LFC Areas constituting a LFC Block shall have the right to define in the LFC Block Operational Agreement internal limits for the Exchange of FCR between the LFC Areas of the same LFC Block in order to: o avoid internal congestions in case of the activation of FCR; o ensure an even distribution of FCR Capacity for the case of network splitting; and avoid that the stability of the FCP or the Operational Security is affected.

3. In case of the Exchange of FCR, the Reserve Connecting TSO and Reserve Receiving OST shall perform a notification process according to Article 162.
4. Any Reserve Connecting TSO, Reserve Receiving TSO or Affected TSO involved in the Exchange of FCR has the right to refuse the Exchange of FCR in case the Exchange of FCR would result in power flows in violation of the Operational Security Limits when activating the FCR Capacity.
5. Each affected OST shall verify that its Reliability Margin is sufficient to accommodate the flows resulting from the activation of the FCR Capacity subject to the Exchange of FCR.
6. The Reserve Connecting OST shall be responsible for the requirements according to Article 166 and Article 167 with regards to the FCR Capacity subject to the Exchange of FCR.
7. The FCR Providing Unit or Group shall only have a responsibility for FCR activation towards its Reserve Connecting TSO.
8. The involved TSOs shall ensure that Exchange of FCR does not hinder any TSO to fulfil the reserve requirements according to the provisions of Article 167.

Article 173. Sharing of FCR within a synchronous area

1. It is prohibited for a TSO to perform Sharing of FCR with other TSOs of its Synchronous Area in order to fulfil its FCR Obligation and to reduce the total amount of FCR of the Synchronous Area as defined in accordance with Article 165(1).

Article 174. General requirements for the exchange of FRR and RR within a synchronous area

1. All TSOs of a Synchronous Area shall define in the Synchronous Area Operational Agreement the roles and the responsibilities of the Reserve Connecting TSO, the Reserve Receiving TSO and the Affected TSO for the Exchange of FRR and/or RR.
2. In case of the Exchange of FRR/RR, the Reserve Connecting TSO and Reserve Receiving OST shall perform a notification process according to Article 162.
3. The Reserve Connecting and Reserve Receiving TSOs involved in the Exchange of FRR/RR shall define in a FRR or RR Exchange Agreement their roles and responsibilities including but not limited to:
   a) the responsibility of the Reserve Instructing TSO for the FRR/RR Capacity subject to the Exchange of FRR/RR;

   b) the amount of the FRR/RR Capacity subject to the Exchange of FRR/RR;

c) the implementation of the Cross-Border FRR/RR Activation Process according to Article 159 and Article 160;

d) FRR/RR Technical Minimum Requirements related to the Cross-Border FRR/RR Activation Process where the Reserve Connecting TSO is not the Reserve Instructing TSO;

e) the implementation of the FRR/RR Prequalification for the FRR/RR Capacity subject to the Exchange of FRR/RR according to Article 169(3) and Article 171(3);
f) the responsibility to monitor the fulfilment of the FRR/RR Technical Requirements and FRR/RR Availability Requirements for the FRR/RR Capacity subject to the Exchange of FRR/RR according to Article 169(5) and Article 171 (5) ; and
g) procedures to ensure that the Exchange of FRR/RR does not lead to power flows in violation with the Operational Security Limits.

4. Any Reserve Connecting TSO, Reserve Receiving TSO or Affected TSO involved in the Exchange of FRR/RR has the right to refuse the Exchange of FRR/RR in case the Exchange of FRR/RR would lead to power flows in violation of the Operational Security Limits when activating the FRR/RR Capacity subject to the Exchange of FRR/RR.
5. The involved TSOs shall ensure that Exchange of FRR/RR does not prevent any TSO from fulfilling the reserve requirements according to the FRR or RR Dimensioning Rules.
6. All TSOs of a LFC Block shall define in the LFC Block Operational Agreement their roles and the responsibilities as the Reserve Connecting TSO, the Reserve Receiving TSO and the Affected TSO for the Exchange of FRR and/or RR with TSOs of other LFC Blocks.

Article 175. General requirements for the sharing of FRR and RR within a synchronous area

1. All TSOs of a Synchronous Area shall define in the Synchronous Area Operational Agreement the roles and responsibilities of the Control Capability Providing TSO, the Control Capability Receiving TSO and the Affected TSO for the Sharing of FRR/RR.
2. In case of the Sharing of FRR/RR, the Control Capability Providing TSO and Control Capability Receiving OST shall perform a notification process according to Article 162.
3. The Control Capability Receiving TSO and the Control Capability Providing TSO participating in the Sharing of FRR/RR shall define in a FRR or RR Sharing Agreement their roles and responsibilities including but not limited to:
   a) the amount of FRR/RR Capacity
   b) the implementation of the Cross-Border FRR/RR Activation Process according to Article 159 and Article 160; and
   c) procedures to ensure that the activation of the FRR/RR Capacity subject to the Sharing of FRR/RR does not lead to power flows in violation with the Operational Security Limits.
4. Any Control Capability Providing TSO, Control Capability Receiving TSO or Affected TSO involved in the Sharing of FRR/RR has the right to refuse the Sharing of FRR/RR in case the Sharing of FRR/RR would lead to power flows in violation of the Operational Security Limits when activating the FRR/RR Capacity subject to the Sharing of FRR/RR.
5. In case of the Sharing of FRR/RR, the Control Capability Providing OST shall make available part of its own FRR/RR Capacity required to fulfil its reserve requirements for FRR and/or RR resulting from the FRR/RR Dimensioning Rules of Article 168 and Article 170 to the Control Capability Receiving TSO. The Control Capability Providing TSO can be either:
   a) the Reserve Instructing TSO for the FRR/RR Capacity subject to the Sharing of FRR/RR; or

b) the TSO having access to its FRR/RR Capacity subject to the Sharing of FRR/RR through an implemented Cross-Border FRR/RR Activation Process as part of an FRR/RR Exchange Agreement.

6. Each Control Capability Receiving OST shall remain responsible to cope with incidents and imbalances in case the FRR/RR Capacity subject to the Sharing of FRR/RR are unavailable due to:
   a) constraints for Frequency Restoration or Replacement Power Interchange related to Operational Security;
   b) partial or full usage of the FRR/RR Capacity by the Control Capability Providing TSO.
7. All TSOs of a LFC Block shall define in the LFC Block Operational Agreement their roles and the responsibilities as the Control Capability Providing TSO, the Control Capability Receiving TSO and the Affected TSO for the Sharing of FRR and RR with TSOs of other LFC Blocks.

Article 176. Exchange of FRR within a synchronous area

1. The Exchange of FRR within a Synchronous Area is allowed in accordance with the provisions of this article and Article 174. The TSOs in a Synchronous Area consisting of more than one LFC Block involved in the Exchange of FRR within the Synchronous Area shall ensure to respect the requirements and limits as defined in Table below:

Synchronous Area	**Exchange of FRR allowed between**	**Limits for the Exchange of FRR**
Synchronous Area CE	TSOs of different LFC Blocks	The TSOs of a LFC Block shall ensure that at least 50 % of their total combined FRR Capacity resulting from the FRR Dimensioning Rules and before any reduction due to the Sharing of FRR according to Article 168 remains located within their LFC Block.
	TSOs of the same LFC Block	The TSOs of the LFC Areas constituting a LFC Block shall have the right, if required, to define internal limits, for the Exchange of FRR between the LFC Areas of the LFC Block in the LFC Block Operational Agreement as to: o avoid internal congestions due to the activation of the FRR Capacity subject to the Exchange of FRR; o ensure an even distribution of FRR throughout the Synchronous Areas and LFC Blocks in case of network splitting; and o avoid that the stability of the FRP or the Operational Security is affected.

Article 177. Sharing of FRR within a synchronous area

1. Any TSO of a LFC Block shall have the right to perform Sharing of FRR with other LFC Blocks of its Synchronous Area within the limits set by the FRR Dimensioning Rules in Article 46(1) while respecting the general provisions of Article 175.

Article 178. Exchange of RR within a synchronous area

1. The Exchange of RR within the Synchronous Area is allowed in accordance with the provisions of this Article and Article 174. All TSOs in a Synchronous Area consisting of more than one LFC Block

involved in the Exchange of RR within the Synchronous Area shall ensure to respect the requirements and limits for the Exchange of RR as defined in the following Table:

Synchronous Area	**Exchange of RR allowed between**	**Limits for the Exchange of RR**
Synchronous Areas CE	TSOs of different LFC Blocks	The TSOs of the LFC Areas constituting a LFC Block shall ensure that at least 50 % of their total combined RR Capacity resulting from the RR Dimensioning and before any reduction of RR Capacity as a result of the Sharing of RR according to Article 170 remains located within their LFC Block.
	TSOs of the LFC Areas of the same LFC Block	The TSOs of the LFC Areas constituting a LFC Block shall have the right, if required, to define internal limits for the Exchange of RR between LFC Areas of the LFC Block in the LFC Block Operational Agreement as to: o avoid internal congestions due to the activation of RR Capacity subject to the Exchange of RR; o ensure an even distribution of RR throughout the Synchronous Area in case of network splitting; and o avoid that the stability of the RRP or the Operational Security is affected

Article 179. Sharing of RR within a synchronous area

1. Each TSO of a LFC Block shall have the right to perform Sharing of RR with other LFC Blocks of the same Synchronous Area within the limits set by the RR Dimensioning Rules in accordance with Article 170 while respecting the provisions of Article 175.

Article 180. Cross-border activation process for FRR / RR

1. The cross-border activation of FRR and RR Capacity between TSOs of the same or different Synchronous Areas is allowed in accordance with the provisions of Article 159 and Article 160.

Article 181. Time control process

1. The Electrical Time Control Process of a Synchronous Area shall be used to ensure that the average value of the System Frequency is equal to the Nominal Frequency.
2. The TSOs of a Synchronous Area shall define in the Synchronous Area Operational Agreement the methodology to correct the Electrical Time Deviation which shall include:
    a) time ranges within which the Electrical Time Deviation shall be maintained by the reasonable endeavors of TSOs.
    b) Set Point Frequency adjustments to return Electrical Time Deviation to zero;
    c) commonly agreed actions to increase or decrease the average System Frequency by means of Active Power Reserves.
3. Where applicable, all TSOs of a Synchronous Area shall appoint one OST which shall:
    a) monitor the Electrical Time Deviations;
    b) calculate the Set Point Frequency adjustments;
    c) coordinate the actions of the Time Control Process.

Article 182. Reserve providing units connected to the OSHE grid

1. OST and OSHE shall collaborate and use reasonable endeavors to facilitate and enable the delivery of Active Power Reserves by Reserve Providing Groups or Reserve Providing Units located in Distribution Networks.
2. The Reserve Connecting OSHE shall process the application of Reserve Providing Unit or Reserve Providing Group connected to its Distribution Network within 2 months after provision of the notification and all the required information including:
   a) voltage levels and Connection Points of the Reserve Providing Units or Groups;
   b) the type of Active Power Reserves;
   c) the maximum Reserve Capacity provided by the Reserve Providing Units or Groups at each Connection Point; and
   d) the maximum rate of change of Active Power for the Reserve Providing Units or Groups.
3. During the Prequalification of a Reserve Providing Unit or Reserve Providing Group connected to OSHE and in accordance with applicable legislation, OSHE shall have the right to set limits to or exclude the delivery of Active Power Reserves located in its Distribution Network in cooperation with the OST and in a non-discriminatory and transparent way based on technical arguments such as the geographical distribution of the Reserve Providing Units and Reserve Providing Group.
4. In accordance with applicable legislation, OST shall agree with OSHE on procedures and methodologies for the information exchange required in relation to Prequalification and the delivery of Active Power Reserves.

Article 183. Information on operational agreements

1. OST shall inform National Authority Regulator or when applicable national relevant authority, for the content of Synchronous Area Operational Agreement, no later than one month before its entry in force.
2. TSO of LFC Block (when block has more than one TSO) shall share the contents of its LFC Block Operational Agreement with National Regulatory Authority no later than one month of entry in force.

Article 184. Information on frequency quality

1. Whenever modified values are defined in accordance with Article 148(5), TSOs of each Synchronous Area shall make the adopted values available to ENTSO-E for publication no later than one month before the entry into force of the Synchronous Area Operational Agreement in which they are contained:
   a) the Frequency Quality Defining Parameters; and
   b) the Frequency Quality Target Parameter.
2. The methodology used to determine the risk of FCR Exhaustion shall be available to ENTSO-E for publication no later than three months before the entry into force of the Synchronous Area Operational Agreement in which it is contained.
3. The Synchronous Area Monitor shall make the results of the Criteria Application Process available to ENTSO-E for publication no later than three months after the last time stamp of the measurement period and at least four times a year. These results shall comprise at least:
   a) the values of the Frequency Quality Evaluation Criteria as calculated for the Synchronous Area and for each LFC Block within the Synchronous Area in accordance with Article 149;
   b) The measurement resolution, measurement accuracy and calculation method defined in accordance with Article 150.

Article 185. Information on the load-frequency control structure

1. All TSOs of Synchronous Area shall make the following information available to ENTSO-E no later than three months before the entry into force the following data:
   a) information on the Process Activation Structure of the Synchronous Area, including at least information on the defined Monitoring Areas, LFC Areas and LFC Blocks and their TSOs; and
   b) Information on the Process Responsibility Structure of the Synchronous Area, including at least information on the defined processes listed in Article 153.
2. All TSOs implementing an Imbalance Netting Process shall publish information regarding this Imbalance Netting Process in accordance with national legislation. This information shall include at least the list of participating TSOs and the starting date of the Imbalance Netting Process.

Article 186. Information on FCR

1. The dimensioning approach for FCR in accordance with Article 165 shall be available to ENTSO-E for publication no later than one month before its applicability.
2. The total amount of FCR Capacity for Synchronous Area and the shares of FCR Capacity required for each TSO defined in accordance with Article 165, as the Initial FCR Obligation, shall be available to ENTSO-E for publication no later than one month before their applicability.
3. FCR properties defined for Synchronous Area in accordance with Article 166 and additional requirements for FCR Providing Groups shall be available to ENTSO-E for publication no later than three months before their applicability.

Article 187. Information on FRR

1. OST as a LFC Block shall make available to ENTSOE for publication, the FRR Availability Requirements, requirements for the control quality and the technical requirements for the connection defined in accordance with Article 169, no later than three months before their applicability.
2. OST as a LFC Block shall make available to ENTSOE for publication, the FRR Dimensioning Rules defined for its LFC Block in accordance with Article 168 no later than three months before the entry into force of the LFC Block Operational Agreement in which they are contained.
3. All TSOs of each Synchronous Area shall make an outlook of the FRR Capacities of each LFC Block for the next year available to ENTSO-E for publication no later than 30 November of each year.
4. All TSOs of each Synchronous Area shall make the actual FRR capacities of each LFC Block of the past quarter available to ENTSO-E for publication no later than 30 days after the end of the quarter.

Article188. Information on RR

1. OST as a LFC Block that operates a Reserve Replacement Process shall make available for publication to ENTSOE, the RR Availability Requirements, the technical requirements for the connection defined in accordance with Article 171, no later than three months before their applicability.
2. All TSOs of each Synchronous Area shall make an outlook of the RR Capacities of each LFC Block for the next year available to ENTSO-E for publication no later than 30 November of the current year.
3. All TSOs of each Synchronous Area shall make the actual RR Capacities of each LFC Block of the past quarter available to ENTSO-E for publication no later than 30 days after the end of the quarter.

Article 189. Information on sharing and exchange

1. All TSOs of Synchronous Area shall make the annual compilations of the agreements for Sharing of FRR and for Sharing of RR for each LFC Block, available to ENTSO-E as part of the material for publication required by respectively Article 187(3) and Article 188(2). These compilations shall include the following information:
   a) the identity of the LFC Blocks between which an agreement for Sharing of FRR or RR exists; and
   b) The realized reduction of FRR and RR due to each agreement for the Sharing of respectively FRR or RR.
2. All TSOs of each country shall publish information on the Exchange of FCR, FRR and RR in accordance with national legislation.

CHAPTER VII

MARKET OPERATION CODE AND THE RULES OF METERING

Article 190. Cooperation between OST and Market Operator

1. To perform system management functions, for Transmission System Operator's needs, Market Operator shall prepare and forwards, relevant information necessary for the Transmission System Operator.

Article 191. Function and operation according to the Market Model Roles

1. In accordance with the Law No.43 / 2015 "On Power Sector" and Market Model OST sh.a operates as an independent state company that carries the following functions:
   a) Transmission Network Operation (network ownership , maintenance and expansion);
   b) System Operation in accordance with the requirements of Directive 2009/72 / EC, including dispatching;
   c) Provision of connectivity service to all system Users connected to transmission network through non-discriminatory procedures;
   d) Defining the criteria to become a Balance Responsible Party and a Balancing Service Provider;
   e) Implementation of the Coordinated Capacity Calculation Processes in accordance with the requirements on organized markets;
   f) Balancing Market operation with the following functions:
      i. Forecast and purchase ancillary services, separated into balancing energy and balancing reserves, from all Balance Services Providers (BSPs), on a weekly, day ahead and real time timeframe and market basis.
      ii. Take the required balancing actions, by activating downward or upward regulation (power) from procured balancing reserves and/or additional balancing reserves bidding into the market for balancing energy.
      iii. To Purchase transmission losses on a day-ahead basis on the organized market. For the transitory period before the go-live of the DAM, weekly procurement procedures are permitted for TSO.

iv. Receive compensation for its balancing services, ensuring financial neutrality on a monthly basis, through the settlement of imbalances based on an imbalance settlement mechanism, ensuring the right incentives for market participants to be balanced in real-time and close to real-time. Imbalance price mechanisms reflect deviations between generation, traded energy and consumption of all Balance Responsible Parties and of each Balance Responsible Party; it is based on a single price system penalizing deviations in both directions.
v. Manage the required metering collection of metered data to perform an efficient energy imbalance management and settlement.
vi. The energy imbalance price will be set based on the real cost for the TSO to balance the system for the given period covering balancing reserves and energy and the imbalance price to be paid by BRPs will be based on this price.

ERE shall regulate the fees, terms and conditions of access to transmission System .

Article192. Market participants obligations towards OST and MO

1. In accordance with the Market Model, Market Rules and Codes, in addition to the obligations defined in the relevant licenses and/or other rules every market participant has an obligation as follows:
    a) To submit to OST and to Market Operator the required information, in accordance with this Code and the Market Rules in force;

Article193. Metering Rules

1. The rules for electricity metering, defines the rights and responsibilities of OST, all Transmission Network Users and market participants, in order to:
    a) measure of all power inflows / outflows in network,
    b) meter readings, and receiving data from electricity meters;
    c) Data processing and delivery of settlements in the energy market.
2. The rules define the technical requirements for transformers, electricity meters and ancillary equipment in all of connection points or interconnection with transmission system, and to define too, all the necessary data relating to a specific metering point.
3. Transmission System Operator is responsible for measuring activity and the service of meter reading in the network, in accordance with ownership boundary with Transmission System Operator as defined by law.
4. The provisions of such rules, apply to measuring points of all countries which provides electricity to OST's transmission facilities , or User's Transmission System Facilities, directly connected , namely, interconnected with transmission system.
5. The provisions of those rules apply to the measuring points at 400/220 kV, 400/110 kV and 220/110 kV transformers tracts in the medium voltage side within the transmission network.
6. Electricity injected to the network or supplied to end customers is measured by metering equipment in accordance with the Network and Metering Code, as well as legislation on metrology.
7. OST should undertake measures to meter and / or measuring system to be in accordance with the requirements of law no. 43/2015 "On the Power Sector", Article 76, paragraph 3 regarding with the seal, stamping and accuracy.

Article 194. Metering Point Installation

1. If all technical preconditions are met, the Metering Point is located on the voltage of Delivery Point.
2. Where the Delivery Point and Metering Point are not on the same voltage, or if they are at the same voltage but they are distant from each other that the power losses between them cannot be disregarded, it is necessary to use Correction Factor applied to metering data for the value of power losses from the Delivery Point to the Metering Point (transferred to the Delivery Point).The use of Correction Factor is carried out during the settlement process and is its integral part.
3. Correction Factor is determined by OST based upon the technical specification of the equipment, calculation of losses between the Delivery Point and the Metering Point under average operational conditions. The Correction Factor is stipulated in:
   a) Connection Decision of the end user's or generator's facility;
   b) Contract for Inter-connection of Distribution and Transmission system;
   c) Operational Agreement for end user's or generator's facilities, when Correction Factor is changed during the course of the facility operation;
   d) Contract for access to the transmission system.
4. The method and conditions of change of Correction Factor is governed between OST and the transmission system user.
5. On each Metering Point, the metering equipment includes:
   a) Instrument Transformers;
   b) Electricity meters;
   c) Measurement and auxiliary electrical circuits;
   d) Communication and Auxiliary Equipment;
   e) Metering- Terminal Box and metering cabinet
6. Access to measure and sealing metering system must be performed by OST in accordance with legal provisions and implementing rules as follows:
   a) Electricity meters, monitoring and communication devices shall be placed in metering safe cabinet, located in an area easily accessible, barrier-free, and well lighted, if necessary with artificial lighting from user network that asks to connect to Transmission System.
   b) The cabinet shall be in accordance with manufacturer's recommendations for measuring environmental conditions and its design should at least include protection from moisture and dust and physical damage, including vibrations and ensure proper temperature control.
   c) The Cabinet shall be equipped with a lock and transparent cover and sealed by OST. The OST checks seales from time to time in accordance with the relevant practical procedures. The seal can be broken / opened only by OST or OST's approval.
   d) Access to internal measurement devices, circuits and associated communication equipment shall be made only with OST's approval and guidelines established by OST.
   e) The User shall allow OST its representatives, rights of entry, pass and stay on any part of the property of the users to the extent necessary, for the purposes of performing its functions pursuant the Transmission Grid Code. Users will make all reasonable adjustments and will provide all necessary facilities for OST or its representatives exercise these rights.
   f) The rights, in accordance with paragraph above shall include the right to use vehicles, plant, machinery for maintenance or other materials that may be required by OST to perform its functions in relation with metering within code frame.

7. Metering equipment at the connection point will be maintained by OST in the presence of the user. All test results, maintenance programs and data sealing will take place throughout the period that the devices are working and for five years after their exit from the Asset Inventory. Details of equipment and testing data will be made available to interested parties in accordance with confidentiality requirements of.
8. The OST will repair measurement system as soon as practicable if a measurement system does not work properly or requires maintenance. The OST will invoice in a proper manner the services offered.
9. After each measuring system interventions due to scheduled maintenance or in case of a fault, and periodically, as appropriate, the verification of measurement shall be in accordance with the provisions of Law no. 43/2015 "On the Power Sector", Article 77.

Article 195. Aksesi në të dhënat e matjes

1. Direct access to metering data at the meter a via remote and local communication is granted only to OST authorized persons for the purpose of configuration, maintenance, validation, data substitution and acquisition and to the users of metering data. The users of metering data are:
    a) Transmission system user or his authorized representatives for the purpose of observation and collection of metering data related to its Metering Point;
    b) Supplier of transmission system users;
    c) Other responsible persons in accordance to the laws and regulations.
2. OST is liable for the organization and delivering of access to metering data and for definition of the user's access rights, having in mind the safety of local data in the facility and in the metering database.
3. OST have to delegate the right of remote access to metering data on the meter by means of defining the list of authorized users of the metering data in order to prevent conflicts among the authorized Parties. EMS shall allocate the time window for the access to metering data taking into account the needs for acquisition of data by EMS and the other users of metering data in accordance to the principle of non-discrimination
4. Non-compliance to the provisions governing the allocated time window for the access to metering data shall result in cancelling the right for the access there to.
5. If the user of metering data is requesting so, EMS shall grant direct access to the meter at Metering Point by allowing the access to the relevant communication port of the meter for the local and remote meter reading as follows:
    a) Generally, through *IR* communication port according to *IEC 62056-21*;
    b) Alternatively, through serial communication port and *DLMS* protocol according to *IEC 62056-42/46/53/61/62.*

    OST can grant the user of metering data the right to perform meter reading by itself, provide the passwords for the meter access and time window for such communication.
6. It is the obligation of the user of metering data to use official, licensed softwareapplications for the remote communication and transfer of data from the meter, as well as to use exclusive passwords for self-reading provided by EMS.
7. OST has to ensure safety of locally registered data on the meters, as well as safety of metering database and registers inside the meters.
8. OST has no authorization to alter data locally registered in the meters, except during the period of meter testing and checking of the installation (only for the period of testing duration).A report is made for any on-site intervention on electricity meters and such report must contain data of unregistered or incorrectly registered electric energy.

9. In any case related to gaining access to measurement data and telematry, OST will comply with the requirements as follows:
    a) OST shall make officially available the measured data for authorized users according to code's provisions in an agreed form between parties.
    b) OST will publish all the formats in which it can provide user's data. All formats will be designed / modified and negotiated between OST and relevant users. OST will store all customer data in one central database ensuring that the database is maintained and constantly updated.
    c) OST will provide measurements data on stakeholders's request in non-standard format against the relevant costs that are covered by the interested party.
    d) OST will manage time schedules of access measurement's database and safety requirements specifications.
    e) Measurement data for use in energy trading and invoicing, constitute confidential information.
10. The OST shall apply the following procedure regarding the reconciliation of measurement:
    a) OST shall make the necessary adjustments to read remotely the cumulative energy values of each month for control purposes.
    b) If the cumulative energy values are not available or can not be read remotely, then OST shall read them manually them month for the above purposes.
    c) Within three weeks of reading the manual measurement, OST will prepare a statement of reconciliation in which it will record the difference between the two successive measurement, and will compare it with the total energy recorded for the same period.
    d) If OST notice any difference between reading manually and electronically recorded of more than 0.1% this information will be noted and referred for further examination.
    e) If, as a result of the above control, the discrepancy is confirmed, then OST will inform the relevant user and will take appropriate measures to address the situation in accordance with relevant legal and regulatory provisions.
    f) If the measurement data is unavailable or inaccessible for more than a month, the data shall be replaced with a reference value, according to relevant methodology adopted by Energy Regulatory Authority, applicable for a period time not longer than three months.

Terms and definitions of Transmission Network Code

In this Code terms and definitions shall apply :

"Network access", the right of users to have opportunities of connections to Transmission Network and the implementation of legislation in force for the Transmission Grid services.

"Aggregator" means a legal entity which is responsible for the operation of a number of Demand Facilities by means Of Demand Aggregation;

"Fault" meansall types of short-circuits: single-phase, double and triple-phase, with and without earth contact,that means further a broken conductor, interrupted circuit, or an intermittent connection, resulting in permanent non-availability of the affectedTransmission System element;

'black start capability' means the capability of recovery of a power-generating module from a total shutdown through a dedicated auxiliary power source without any external electrical energy supply to the power-generating facility;

"Application for Transmission Grid Connection" means a set of documents filled by new grid users that require access for connection to the transmission network, or by existing grid users, to modify their existing connection. These documents are developed pursuant with the provisions of the Transmission Network Code for geting approval for grid connection , by OST.

"De-energizing" means the physical act of separation-disconnection of systems / network Users facilities from the Transmission Network Transmission .

" Property Diagram " is a diagram (scheme) that shows the number and the name for each location, prepared to show the connections and ownership on network elements for each entity/ Party.

"Dispatching" means the activity performed by the Transmission System operator consisting on real-time management of the power flows and the application of the necessary provisions to the coordinated operation of the system components, including production plants, transmission grid and the ancillary services necessary for system operation Dispatching means the power system operation in order to maintain the balance between production, import / export and electricity consumption at national level, while maintaining the security and reliability of network operation Transmission System Network.

"**ENTSO-E** (European Network of Transmission System Operators for Electricity)" is the European Network of Transmission System Operators of Electricity.

"Energy Regulatory Authority" or **"ERE"**, is the national regulatory authority of power sector and natural gas.

"Power factor" means the ratio of the absolute value of active power MW to apparent power MVA (cosφ) ;

"frequency" means the number of alternative current cycles per second of Power System .

"Force Majeure" is an natural or social act or event such as earthquakes,lightning, cyclones, floods, volcanic eruptions, fires or wars, armed conflict, insurrection, terrorist or military action, which prevent a licensee from performing his obligations under the license or other acts or events that are beyond the reasonable control and not arising out of the fault of the licensee, and where the licensee has been unable to overcome such act or event by the exercise of due diligence and reasonable efforts, skill and care.

"**Installed Capacity**" means nominal capacity of a power-generating module, based on manufacturered documentations (certificate of generator) written in the respective target for each power generating module (kW or MW).

"Maximal Power of a power generating module" means, potential maximum active power in MW that a power generating module can provide in certain mechanical and electrical conditions
"FCR" – frequency containment reserves (Reserves of Primary Control)
"FRR" – Frequency Restoration Reserves (Reserves of Secondary Control)
"RR"- Replacement Reserves (Reserves of Terciary Control)
"FRCE" – Frequency Restoration Control Error , or ACE or program deviation ;
"System States" means the operational condition of Transmission System regarding operational security limits, whereas differ 5 states: Normal, Alarm, Emergency, Blackout and Restoration;
"Interconnector" means a transmission line builded by Transsmission System Operator or a third Party which crosses or spans a border between Albania and another country and which connects the national transmission systems of the both countries.
Incident (failure)" is a phenomenon that occurs due to internal or external reasons and causes the failure of electricity parameters or disconnection for a specified period of time of one or more elements that on the other side lead to electricity supply interruption for the Clients.
"Load profile" means the load progress hour-based (00 –24 hours) per day, or another time period for a specified grid element.
"Transmission Code" - is a set of standards and technical rules, which regulate the operation of the transmission system and defines the conditions of service that are provided by the Transmission System Operator to grid users in accordance with ENTSO-E.
"Metering Code" is a set of minimum standards required for the measurement / telemetry and energy registration.
"Voltage Control" means balancing of respectiv reactive power requirements of the network and the customers with the propose of maintaining of acceptable voltage profile throughout the network. The purpose of voltage control is to maintain an acceptable voltage profile This is achieved by balancing of the respective reactive power requirements of the network and the customers with the propose of mainaining of acceptable voltage profile throughout the network.
"Automatic Voltage Control" means the automatic control actions at the generation node, at the end nodes of the AC lines or High-Voltage DC lines, on transformers, or other means, designed to maintain the set voltage level or the set value of Reactive Power.
"congestion" means a situation in which an interconnection linking national transmission networks cannot accommodate all physical flows resulting from international trade requested by market participants, because of a lack of capacity of the interconnectors and / or the national transmissi concerned.
"Secured condition operation ", means, operational system network states whereas the grid status meets the (n-1) criterion and static and dynamic stability criteria.
"LFC"- is an acronym used for Load-Frequency Control.
"technical Losses" means technical losses of a network element that are equal to difference between energy injected in the element and the measured energy exited from the element.
"protection" are equipment (IED) applied to electric power systems to detect abnormal and intolerable conditions . They initiate activation of alarm signals and provide relevant signals, up to disconnection of injured network element.
"Common Grid Model" or "CGM " means a Union-wide data set agreed, between various TSOs describing the main characteristic of the power system used as an unique base for year,month dayahead and intraday security analysis
"Synchronous power-generating module" means an indivisible set of installations which can generate electrical energy such that the frequency of the generated voltage, the generator speed and the frequency of network voltage are in a constant ratio and thus in synchronism;

"Generation adequacy" means the assessment of the ability of in-feeds into an area to meet the load in that area.**"Commission Regulation (EC) 2016/631",** is Commission Regulation (EU) 2016/631 dt. 14 April 2016 regarding the requirements for generators connections to the network.

"Interruptions in Power System" means, interruption of electricity supply as a result of the disconnection of network elements in Power System (elements can be power lines, primary electrical equipment and other installations in a substation, generating unit, system / facility, transmission grid users as client, etc.).

"Planned autages" means an autages planned and agreed between OST and grid users. Planned outages also mean outages of a part of Transmission Network for maintenance, rectification or overhauls that may affect the power supply of Clients.

"Final operational notification' or 'FON' means a notification issued by the relevant system operator to a power- generating facility owner, demand facility owner, distribution system operator or HVDC system owner that complies with the relevant specifications and requirements, allowing them to operate respectively a power-generating module, demand facility, distribution system or HVDC system by using the grid connection;

"Energisation operational notification" or 'EON' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner prior to energisation of its internal network;

"Interim operational notification" or "ION" means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner which allows them to operate respectively a power-generating module, demand facility, distribution system or HVDC system by using the grid connection for a limited period of time and to initiate compliance tests to ensure compliance with the relevant specifications and requirements;

"Limited operational notification" or "LON' means a notification issued by the relevant system operator to a power-generating facility owner, demand facility owner, distribution system operator or HVDC system owner that had previously attained FON status but is temporarily subject to either a significant modification or loss of capability resulting in non-compliance with the relevant specifications and requirements.

"Load" means an equipment or customer which consumes electric power from the Power System. Load should not be confused with the Demand that is the metered amount of power required or received by the Load.

"Peak load (max) " means the maximum of active power in MW measured and registred within a period of time day-based (00.00-24.00 hrs)

"Contingency" means the unexpected failure or outage of a system component, as a result of an incident

"**Outage notice"** is a notice issued by a Grid User, pursuant to respective provisions of Transsmission Code, announcing OST for an unplanned outage or a notice issued by OST to the Grid Users announcing an unplanned outage of the Transmission Network that affects power supply of them.

"Norms" means standards, codes, rules, instructions, decisions, procedures and other normative documents established by laws, by -legal acts, national and international standads , other official documents and contracts.

"Agreements for access to the transmission network", means a document signed jointly between OST and applicants to have access to the transmission network.

"Demand-Side Response" means measures to steer the stability of the grid, such as agreed load sheding and/or interruption of supply.

"Balancing mechanism" means a mechanism operated by the OST Market Operator by which bids and offers are accepted in order to achieve a physical balance in the SEE

'Demand facility' means a facility which consumes electrical energy and is connected at one or more connection points to the transmission or distribution system.

"Distribution System Operator or DSO" means a legal person responsible for secure, reliable and efficient operating of the distribution grid, ensuring the maintenance and the development of the distribution system, dispersed at a given area, and if applicable, its connection to other systems in order to provide long-term capabilities to meet the reasonable demands on the distribution of electricity, respecting the environment and electricity efficiency.

"Transmission system operator" means a legal entity responsable for system operation, maintaining and development of transmission system network , including interconnections with neighboring systems to provide long-term ability of the system to fullfill the requirements for transporting Electricity.

"Market Operation" means an activity performed by the Market Operator consisting of management of the electricity market and the completition of financial statements on the imbalances caused by market participants, excluding the purchase or selling of electricity.

"Market Operator", means the responsible licensed for operation, organization and management of the electricity market

"Balance Responsible Party" means a market participant or its chosen representative responsible for its Imbalances during operation.

"Interim derogations"means a temporary permit issued by OST to grid users connected to transmision network, pursuant the procedure detailed in this Code.

"System users" means a natural or legal person supplying to, or being supplied by, a transmission or distribution system.

Significant grid users" means grid users which can effect significantly the flux flow pattern beyond the threshholds defined by OST, as a result of events or actions taken related equipment operations, in its own responsibility.

"Connection point" means physical connection point where a grid user is connected to a transmission system .

"Metering points" means connection points of metering/telemetry eqipments which enable the metering of power flows (full, active, reactive) on that element of the grid .

"Long-term planning" means the planning of the needs for investments, in generation,transmission and distribution capacities, on a long-term basis, aiming to meet the demand of the system for electricity and provide supply to customers.

"Emergency and restoration system plan ", contains technical and organizational guidelines to avoid further extension of the incident in power system, by limiting in this way the consequences , as well as restauration of national power system, to normal state conditions . This plan contains restauration procedures too, to return to normal conditions after partial or total tripping of the power system,in accordance with the provisions of the operational handbook of ENTSOE (OH) and ENTSO-E grid code for "Emergencies and restoration" (NC E & R) .

"Defence Plan" means the summarising of all technical and organisational measures taken to prevent the propagation or deterioration of a power system incident in order to avoid expanding of the failure and collapse.

"**Outage Programing (Scheduling)",** means the outage program scheduled by OST sh.a in coordination with Grid Users, pursuant with this grid code.

"Appealing procedures" are the procedures detailed in the Code for resolving disputes between OST and the Parties (Grid Users).

"Static stability (side small incidents)"means the capability of power system to maintain normal operation conditions when deviation from normal state is very small and within norms and standard of ENTSO-E; Or capability of the power system to return quickly to operational normal

state conditions after one or more deviations have lead it out of defined standard operacional parameters.
"Static stability of grid element" means the calculated maximal active power transferred to a specified element of the Electric Power System to which static operational stability is provided.
"SCADA" is supervisory control and data acquisition of a system or grid user .
"Power scheduling" means active power programmed for generation, in order to meet the forecasted electricity demand.
"Schedule" means a reference set of values representing the Generation, consumption or exchange of electricity between actors for a given time period.
"Normal Operation Scheme" means the normal connection's scheme, of grid elements, to each node, that forms the Power System .
"Region Power System " is the total number of lines, equipment and other auxiliary installations in a certain geographical area of power system.
"**Total black-out of power system"** is the incident which is ocurred due to an internal or external reasons and as a consequence, the disconnection of one ore more grid elements for a certain time , which on the other side leads to interruption of electricity supply in the whole system.
"Market Rules" are detailed rules which determine the mode of operation and management of the electricity market, registration of participants, the responsibility of balancing by participants of the energy market, rules for balancing the electricity system, rules for imbalance calculation for balancing responsible Parties, rules for the financial responsibilities of balancing responsible Parties in the event of imbalance, as well as other issues related to the functioning of this market.
"Transmission Network" means Transmission System Network, which consist in high voltage electric lines in 110 kV, 150 kV , 220 and 400 kV, transformation substations and any other facility whose functions include transmission and interconnection with neighbors. Any assets, involving communications, protection, control, auxiliary services, land, buildings and other auxiliary, electric or not, which is needed for proper functioning of the installations of transmission network , are compound elements of the transmission grid.
"Telecommunication infrastructure" means a set of communication lines, communication nodes, telecommunication devices that provide communication and transmission of communication signals, those telephone, data,teleprotection ..etc.
"Balancing Service Provider" is a Market Participant providing balancing services to OST, based on the contract for participation in the balancing market according to respective rules for providing balancing services for the system .
"Distribution System" means the system of lines, supporting structures, transforming and switching devices, used for electricity distribution and for the delivery to its customers**,** excluded supply **.**
"Transmission Services" are services that provide electricity transmission between two or more points of Transmission Network according to parameters of network quality service
"Balancing Service", is providing of contracted reserve capacity and / or balancing energy used by the Transmission System Operator to perform balancing.
" System Technical Services" are services provided by OST and grid users in order to maintain the operational security level, during operation of the power system and the quality of generated electricity , transmitted, distributed and supplied. Parameters defined in this case are based on norms, methodologies and relevant rules.
"Ancillary services" means services necessary for reliable operation of the transmission or distribution system;
"Balancing market" means market-based management of the functions of balancing of the power system operated by the Transmission System Operator.

“Electricity market” means a system where are performed effecting purchases, through bids to buy sales, through offers to sell; for long and short-term trades.
“Trader” means any legal person who carry out the activity of electricity trade;
"Electricity Trading" is the process carried out by a legal person who purchases electricity for the purpose of reselling it within or outside the country where the system operates.
“(N-1) Criteria “ means criteria used to verify, plan and design the power system, fulfilled if the following conditions are met:

a) there is no interruption of electricity supply;
b) the system remains unique and sustainable, in normal state operational parameters .

“Operacional instruction” means any command, within its authority, given by system operators which is mandatory to be implemented by the reciver of it. These commands are provided through dedicated phone, phonograms, fax and computer messages and from SCADA .
“Operational action” means action from the unit receiving the Operative Instruction, issued by the system operators, as well as un-programmed actions from the Parties affecting the Power System functioning.
"Remedial action" means, a measure or action that is activated by OST, manually or automatically, to facilitate the consequences of the events, and to maintain the normal state or to return to normal system state operation, which can be applied pre/ after the occurrence of the incident, and may include expenditures;
“Instruction for Synchronization” means an instrucion issued from system operators, towards Power generating modules to synchronize their modules with Trasnmission System Network.

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Planning Data Categories

1. In order to fulfill the above requirements,Users planning data shall be categorized in two groups as follows:
   a) Initial Data of Planned Project
   b) Obligatory Data of Planned Project
2. Each group containing:
   a) StandardPlanning Data
   b) Detailed Planning Data
   c) Annual System Planning Data
   d) Data of the 10 year System Planning
   e) Works in Progress Data
   f) Final Data
3. Each User shall provide these data to OST by September 30 of the following year/years.

Initial Data of Planned Project

1. Data submitted during the application time for Use and Connection to the Transmission System or modification of the existing connection and shall be named as Initial Data of Planned Project.
2. Initial Data of Planned Project shall normally contain only the Standard Planning Data until Detailed Planning Data are specifically required by OST.

Obligatory Data of Planned Project

1. After the acceptance by the User, data submitted to and received from OST based on the Planning Code, shall be named as Obligatory Data of Planned Project. These data will form the base for the Transmission System Planning.
2. The Obligatory Data of Planned Project shall not be considered as confidential in order to include them in OST's data system according to Planning Code provisions and to disclose those data to other Users after receiving their application form for connection and/or use of Transmission System.Data are used only for reasons they were received.
3. Obligatory Data of Planned Project will normally include both Standard and Detailed Planning Data.

Standard Planning Data

Generators

1. Required data are listed in the respective paragraph A.1,Section 1,Annex A
2. Data are submitted with the application for New Connection, additional power generating unit, modification of plants and equipment that influence the Transmission System behavior.
3. Data should be submitted by Users connected to the Transmission System according to respective provisions.
4. Transmission System Operator:OST
   a) Required data are listed in paragraph A.2, Section 1, Annex A

5. Distribution System Operator
    a) Required data are listed in paragraph A.3, Section 1, Annex A
    b) Data should be submitted with the application for new connections, additional lines and substations, and line and equipment modification that may materially affect the Transmission System behavior
6. Clients
    a) Clients data are listed in paragraph A.3,Section 1,Annex A
    b) Data should be submitted with the application for new connections,additional lines and substations, and line and equipment modification that may materially affect the Transmission System behavior
7. Formats
    a) In all cases data shall be submitted in the formats described in Annexes or with a note that covers terms not included in Annexes

Detailed Planning Data Formats

1. Required data are listed in Paragraphs:A.4;A.5;A.6;A.7;A.8;A.9;A.10; A.11; Section 2, Annex A.
2. Users already connected to the Transmission System shall send their data within September 30 of the next year/years.

Annual System Planning Data

1. To be provided by all Users. Required data are listed in section 3, Annex A.
2. Deadline for all Users connected to the Transmission System to send their data within September 30 of next year.

Data of 2 Year Planning

1. To be provided by all User,and the required data are listed in paragraph A.9,Section 3, Annex A.
2. All Users connected to the Transmission System shall send their data for the next 2 years, within September 30.

Working Progress Data

1. To be provided by all Users. Required data are listed in paragraph A.10, Section 3, Annex A.
    a) All Users connected to the Transmission System, shall send their Final data within March 31.

They shall submit data listed in paragraph A.11, Section 3, Annex A. All Users connected to the Transmission System shall send their data at the end of works when ready to connect to theTransmission System.

Annex A –Planning Data

A.1 Generators

1. Thermal Power Plant

a) Connection

1	Connection Point	Indicates a single line diagram of the proposed Connection to theTransmission System
2	Voltage	(kV) Voltage level in Connection points to the Transmission System
3	Planned Time	Average planned time for connection to the Transmission System

b) Plant Capacity

1	Total Capacity of the Plant(MW)	Condition of existing plants. Capacity of new plants,divided in phases
2	Number of units and their capacity	n x MW

c) Data of Generating Units

1	Steam Generating Unit	Condition,type, capacity,steam pressure,steam temperature,etc.
2	Steam Turbine	Condition,type, capacity.
3	Generator (Alternator)	Type Nominal characteristics (Sn,Pn in MVA and MW) Nominal Voltage (Unin kV) Power Nominal Factor(cosΦ) Capacity for Reactive Power (MVAr) Short Circuit Power Directaxis transient reactance (in p.u. ofMVA) Directaxis Sub-transient Reactance (in p.u. of MVA) Auxiliary Power Requirement (Own Needs) in MW Capability Curve of generator Short Circuit Saturation Curve

4	Transformer of Generator-Transformer Block	Type Nominal Power MVA Nominal Voltage kV Nominal Currents(HV/LV) in A Vector group Type of voltage regulator Positive sequence reactance (at maximum,minimum,normal Tap)(%onMVA) Positive sequence resistance(at maximum,minimum,normal tap)(%onMVA) Positive sequence resistance (at maximum,minimum,normal tap)(%oF MVA) Zero sequence reactance(%of MVA) Tap changer range(±%) and steps Type of Tap changer (off-load/on-load) Cooling type (ONAN/ONAF)

d) Power for own needs

1	Total Power in MW and required MVA for auxiliary equipment	In MW and MWA
2	Total external power required to start up	In MW

2. Hydro Power Plant

a) Connection

1	Connection Point	Indicates a single line diagram of the proposed Connection to theTransmission System in a hard and a soft copy
2	Voltage	(kV) Voltage level in Connection points to the Transmission System
3	Type of Hydro Plant	Description of the Plant: with Reservoir orRun-of-River; indicators of work (total reserved volume, active reserved volume, maximal level of water, maximal level of work,minimal level ofwork,flows, etc)

b) Plant Capacity

1	Total Capacity of the Plant (MW)	Condition of existing plants. Capacity of new plants, divided in phases
2	Number of units and their capacity	

c) Data of Generating Units

1	Working Regimes	Maximum,Minimum,Averages.
2	Turbines	Condition,types, capacity.
3	Generator (Alternator)	Type Nominal characteristics (Sn,Pn in MVA and MW) Nominal Voltage (Un in kV) Power Nominal Factor(cosØ) Capacity for Reactive Power (MVAr) Short Circuit Power Direct axis transient reactance (in p.u. of MVA) Direct axis Sub-transient Reactance (in p.u. of MVA) Auxiliary Power Requirement (Own Needs) in MW Capability Curve of generator Short Circuit Saturation Curve
4	Transformer of Generator-Transformer Block	Nominal Power MVA Nominal Voltage kV Nominal Currents(HV/LV) in A Vector group Type of voltage regulator Positive sequence reactance (at maximum,minimum,normal Tap)(%onMVA) Positive sequence resistance(at maximum,minimum,normal tap)(%onMVA) Positive sequence resistance (at maximum,minimum,normal tap)(%oF MVA) Zero sequence reactance(%of MVA) Tap changer range(±%) and steps Type of Tap changer (off-load/on-load) Cooling type (ONAN/ONAF)
5	Data on Transmission Network	

3. Wind park power generators

a) Connection

1	Connection Point	Indicates a single line diagram of the proposed Connection to the Transmission System in a hard and a soft copy.
2	Location	
3	Nominal Voltage	Voltage level in Connection points to the Transmission System
4	Eolic Generator Type	
5	Meterology Data	

b) Generator Capacity

1	Total Capacity of the Plant (MW)	Condition of existing plants. Capacity of new plants, divided in phases.
2	Number of units and their capacity	

c) Data of Eolic power generating units

1	Working regimes	Maximal,minimal,parameters etc
2	Turbines	Type, total capacity
3	Generator	Nominal Absolute Power (Sn in MVA) Nominal Active Power(Pn in MW) Phase Nominal Current(In in A) Nominal Power Factor(cosφ) Nominal Frequency (Fn in Hz) Reactive Power capability (in MWAr) Minimal Power (Pmin in MW) Nominal Speed (Nn in rot/min) Inertia Factor H (MW Sec/MVA) Volant moment (GD^2 in Tm2) Short Circuit Coefficient(Kc) Direct–Axis Synchronous Reactance(Xd in p.u) Direct-Axis Transient Reactance (X" d in p.u) Direct-Axis Sub-Transient Reactance (X" d in p.u) Quadrate-Axis Synchronous Reactance (Xq in p.u) Quadrate-Axis Transient Reactance (X"q in p.u) Quadrate-Axis Sub-transient Reactive(X"q in p.u) Stator Resistance per phase in 75°(Ra in ohm) Direct-AxisTransient Open Circuit time Constant(T''_{d0}in sec) Direct-Axis Sub-Transient Open Circuit Time Constant (T''_{do}in sec) Quadrate-AxisTransient Open Circuit Time constant (T''_{qo}in sec) Quadrate-Axis Sub-Transient Open Circuit Time Constant(T''_{qo}in sec) Time factor of stator"s winding for short circuit (T_s per sec). Open-Circuit Saturation Curve Generator Capability Curve Synthetic inertia

4	Transformer of Generator-Transformer Block	Nominal Power MVA Nominal Voltage kV Nominal Currents(HV/LV) in A Vector group Type of voltage regulator Positive sequence reactance (at maximum,minimum,normal Tap)(%onMVA) Positive sequence resistance(at maximum,minimum,normal tap)(%onMVA) Positive sequence resistance (at maximum,minimum,normal tap)(%oF MVA) Zero sequence reactance(%of MVA) Tap changer range(±%) and steps Type of Tap changer (off-load/on-load) Cooling type (ONAN/ONAF)
5	Data on Transmission network	

d) **Power for own needs**

1	Total Power in MW and required MVA for auxiliary equipment	In MW and MVA

Note 2: For generator's types, not included above, the data will be submitted by OST.

A.2 Transmission Lines

1. Linename (Indicating Plants and substations at the beginning of the line and in the end of the line)
2. Line Voltage in (kV)
3. Line length (KM)
4. Conductors (Type,Section (mm2))
5. Line Parameters (in p.u. and Omik values)

    a) Resistance/km
    b) Inductance/km
    c) Conductivity/km (B/2 in p.u. andμS)
    d) Transmitting capacity in 20^{O}C of ambient temperature(Allowed thermal flow).
    e) Definition of j-economic
    f) Type of poles to be used and respective parameters
    g) Line Route (information on the landscape traversed by the line)
    h) LineMap(informationonthetopographicmapindicatingtheproposedand existing lines)
    i) For existing Lines give the time when the line will be able for operation;
    j) for new lines give the time when it will start to operate(month/ year)

A.3 Distribution System Operator and Clients

1. **General**

Main data for systems / facilities, managed by the distribution system and transmission system network Clients;

1.	Map (in scales) of Distribution System Operator and Clients extension area	Indicates the area where Distribution SystemOperator andEligible Customers exercise their activity according to the license.
2	Data for Eligible Customers and data for their loads.	Furnish data of Clients and, their connected loads)
3	Data on Distribution System Operator and Clients systems/objects.	Data as consumers ,in MW,MVA

2. **Connection**

1	Connection Point	Indicates a single line diagram of the proposed Connection to the Transmission System
2	Voltage	(kV) Voltage level in points of Connection to the Transmission System
3	Names of Transmission System Substations that feed the Connection points	

3. **Lines and Substations**

1	Line Data	Indicates line length and voltage level and described parameters in A.2
2	Substation Data	Indicates details of substations directly connected to the Transmission System and details of installed capacitive groups.

4. **Loads**

1	Load in Connection points	Indicates loads and load details in Connection points
2	Details of load directly feed by the Transmission System	Indicates customer name, supply voltage, demand according to the contract, and the name of Transmission System substation, power factor, compensating equipment details,supplying line and line length.

5. **Demand Data**

(Note: This information is required by Clients that applies for connection to the Transmission System)

1	LoadType	(Condition of load supplying point, quantity of Electricity absorbed by the load,its type, etc).
2	Nominal voltage	KV
3	Equipment Electric Load	
4	Load Sensitivity from voltage and frequency of supply.	
5	Maximum of Load harmonics	
6	Average and maximal unbalance of load phases	
7	Nearest substation supplying the load	Data to be provided pursuant to A.3
8	Area mapin scales	(Showing location of load with reference of lines and substations in the vicinity)

6. **Load Forecast Data**
   a) Peak and minimal loa,load forecast for each category of load for each of the succeeding 10 years
   b) Details of methodology and summary of forecasts
   c) Forecast of energy demand for each category and in total for each of the succeeding10 years, accompanied with approximate Daily Load curves
   d) Details of loads directly connected to the Transmission System:
      1. Name of existing or potential Customer
      2. Connection Point and load nature
      3. Feeding Substation
      4. Supply Voltage

Note:points 1-4 shall fill in refering to A.3

7. Equipment of Reactive Compensation

a) For all reactive compensation equipment intended to be connected to the system users, is required the following information:

1. Type of device (e.g static or variable);

2. Nominal capacitive load and / or inductive or its operating band in MVAr;

3. Details of any automatic control which enables defining of operating characteristics;

4. Connection Point of user’s network system in terms of location and voltage system network;

Section 2 – Planning Data

Detailed Planning Data

Power Plants

A.4 Power Plants

1. Thermal Power Plants. General
   a) Name of Power Plant
   b) Units Number and Capacity (MVA)
   c) Nominal Levels of Main Equipment Parameters
   d) Boiler (steam/pressure temperature)
   e) Location of fuel supply
   f) Water supply pumps
   g) Technical Data on Turbines
   h) Technical Data on Generators (Alternators)(MVA)
   i) Technical Data on Transformer Generator(MV)
   j) Technical Data on Auxiliary transformers(MVA)
   k) Single Line Diagram of Power Plant
   l) Schemes of control,Relay protection and metering
   m) Neutral Grounding of Generators
   n) Excitation Parameters
   o) Earthing and values of earthing resistance

Note: Detailed technical data shall be submitted pursuant application forms of the requirements in Section 1.

2. **Relay Protection**

a) Full description, including the settings of all relay protections and installed relay protection systems in Generators and Transformers units, auxiliary Transformers and electric engines of auxiliary equipment
b) Full description, including the settings of all installed relay protection in all exiting lines/feeders from Plants substations and key indicators for commuting actions(time of switch on,time of switch off)
c) Full description of switchers in point/s of Connection to the Transmission System

d) Most probable fault time for electrical faults on the User"s system/objects
e) Details of Protection functions including Instrument Transformers and Cables on Secondary Side.
f) Technical Specifications of telecommunication equipment .

3. **Substations of Power Stations**
   a) For transformers of generator-transformer Block and other power transformers:
      1. Nominal Power MVA
      2. Nominal Voltage kV
      3. Nominal Currents(HV/LV) in A
      4. Vector group
      5. Type of voltage regulator
      6. Positive sequence reactance (at maximum,minimum,normal Tap)(%onMVA)
      7. Positive sequence resistance(at maximum,minimum,normal tap)(%onMVA)
      8. Positive sequence resistance(atmaximum,minimum,normal tap)(%oF MVA)
      9. Zero sequence reactance(%of MVA)
      10. Tap changer range(±%) and steps
      11. Type of Tap changer (off-load/on-load)
      12. Cooling type (ONAN/ONAF)
   b) For commuting equipment including switchers,circuit breakers located in Connection points:
      1. Nominal Voltage (kV)
      2. Type of switchers, circuit breakers
      3. Rated short circuit current 3phase(kA)
      4. Details of autoreclosing Equipment
   c) Details of Control System, local SCADA, RCU (Remote Control Unit),etc..
   d) Isolation Level (kV)
      1. Busbars
      2. Commuting equipment (switchers, circuit breakers)
      3. Vurrent and voltage transformers ;
      4. Transformer branches of voltage regulation
      5. Transformer"s winding
   e) Other Technical Data
4. **Generating Units**
   a. <u>Alternators (Generators)Parameters</u>
      1. Nominal Voltage (Un inkV)
      2. Nominal Absolute Power (Sn in MVA)
      3. Nominal Active Power(Pn in MW)
      4. Phase Nominal Current(In in A)
      5. Nominal Power Factor(cosφ)
      6. Nominal Frequency (Fn in Hz)
      7. Reactive Power capability (in MWAr)
      8. Minimal Power (Pmin in MW)
      9. Nominal Speed (Nn in rot/min)
      10. Inertia Factor H (MW Sec/MVA)
      11. Volant moment (GD^2 in Tm2)
      12. Short Circuit Coefficient(Kc)
      13. Direct–Axis Synchronous Reactance(Xd in p.u)
      14. Direct-Axis Transient Reactance (X" d in p.u)
      15. Direct-Axis Sub-Transient Reactance (X" d in p.u)
      16. Quadrate-Axis Synchronous Reactance (Xq in p.u)
      17. Quadrate-Axis Transient Reactance (X"q in p.u)
      18. Quadrate-Axis Sub-transient Reactive(X"q in p.u)

19. Stator Resistance per phase in 75ºC(Ra in ohm)
20. Direct-AxisTransient Open Circuit time Constant(T'_{d0}in sec)
21. Direct-Axis Sub-Transient Open Circuit Time Constant (T''_{do}in sec)
22. Quadrate-AxisTransient Open Circuit Time constant (T'_{qo}in sec)
23. Quadrate-Axis Sub-Transient Open Circuit Time Constant(T''_{qo}in sec)
24. Timefactor of stator"s winding for short circuit (T_s per sec).
25. Open-Circuit Saturation Curve
26. Generator Capability Curve

Note:Points 14,17,23,25,31 are excluded from data exchange for Power plants without regulation.

b) Exciting System and Voltage Automatic Regulator Parameters

The following data will be used to realize the study of the static and dynamic stability of the transmission system network.

1. Type of Exciter
2. Nominal Current of Exciter (In in A)
3. Nominal Voltage of Exciter(U in V)
4. Exciter maximal Current along Transient Time (Imax. in A)
5. Exciter maximal Voltage (Vmaxin V)
6. Excitation System Transient Response
7. Excitation System Open-Loop Response characteristic
8. Excitation System closed loop Response characteristic
9. Dynamic characteristics of over exciting and limits
10. Dynamic characteristics of under exciting and limits
11. Detailed structured scheme of the whole exciting system that shows details of transmitting functions and parameters of its elements:

    K_a– Voltage Regulator Constant

    T_a– Voltage Regulator Time Constant

    $V_{r\ max}$– Normal Max voltage in exit

    $V_{a\ max}$,$V_{a\ min}$– Maximal and Minimal Voltage of Internal Regulator

Depending on the exciting system type,the structural scheme,transmitting functions and element parameters are based on IEEE standards.

12. According to these standards,the system models help to study the stability and parameters of theTransmission System.

c) Parameters of Regulation and Parameters of Governor
1. Type of Governor
2. The coefficient to define the working range of the Governor (in MW/Hz) as defined by IEEE norms
3. Speed and time Constant (T_{SR})
4. Time constant of server engine and Directing Apparatus(T_{SM})
5. Governor value opening with limit number (C_v. open)
6. Governor valve closing with limit number (C_v. close)
7. Governor valve limit ($C_v$max and C_v.min)
8. Based on steam turbine system in CR-IEEE the following parameters should be provided when necessary.

9. Structural Scheme of Regulating System and Governor showing transmitting functionsofspecial elements recommendedby IEEE

5. **Hydropower Plants**
   a) General
      1. Name of Plant
      2. Number and Capacity of Units (MVA)
      3. Alignment of all major equipment
         i. Turbines
         ii. Generators (MVA)
         iii. Generators-Transformers (MVA)
         iv. Auxiliary transformers(MVA)

Note:The technical data shall submitted pursuant to application forms in section 1.

   b) Single line diagram of Plant;
   c) Scheme of control,relay protection and metering;
   d) Neutral grounding of generator;
   e) Excitation system and AVR;
   f) Earthing with Ground Resistance values;
   g) Reservoir data:
      1. Typical Features
      2. Reservoir Type
         - Multipurpose
         - Only for electricity
      3. Operation table

Note: point e) is excluded for generating units without regulation

   h) Relay Protection

1. Full description that includes settings of all relays protection and relay protection system installed in Generator and Transformer units, Auxiliary Transformers and electric engines of auxiliary equipment.
2. Full description including settings of all installed relay protection in all exiting lines/feeders from Plants substations and key indicators for commuting actions(time of switch on,time of switch off)
3. Full description of switchers in the point/s of Connection to the Transmission System
4. Possible duration of electric breakdowns in Users system/objects
5. Details of relay protection functioning and metering that includes Instrument Transformers and Cables on the Secondary Side

   i) Plant Substations

1. For transformers of generator-transformer Block and other power transformers:

   i. Nominal Power MVA
   ii. Nominal Voltage kV
   iii. Vector group

iv. On Load Losses P_{cu}in kW
v. Short circuit voltage $U_k$in %
vi. No load Losses P_0in kW
vii. No load current I_0in %
viii. Positive sequence reactance(at maximum,minimum,normal Tap) (% on MVA)
ix. Positive sequencere sistance(at maximum,minimum,normal Tap) (% on MVA)
x. Zero sequence reactance(%on MVA)
xi. Tap changer level (±%) and steps
xii. Type of Tap changer (Off load/On load)

2. For commuting equipment including switchers, circuit breakers located in Connection points
   i. Nominal Voltage (kV)
   ii. Type of switchers, circuit breakers
   iii. Rated shortcircuit current 3phase (kA)
   iv. Details of auto-reclosing equipment
3. Details of Control System, local SCADA, RCU(Remote Control Unit),etc.
4. Isolation Level (kV)
   i. Busbars
   ii. Commuting equipment (switchers, circuit breakers)
   iii. Transformer branches of voltage regulation
   iv. Transformer"s winding
5. Other Technical Data

j) <u>Generating Units</u>

1. Generator (Alternator) Parameters
   i. Parameters are equal as for Thermal Power Generators :
   ii. Operating Unit (Regime) Maximal, Minimal, Average
   iii. Discharging ports and their capacity
   iv. Water consumption of generating units for different reservoir (lake) levels;
   v. Characteristics of generating units" turbines
2. Exciting System Control Parameters
   i. Same as parameters of exciting system of thermal plants Alternators
3. Parameters Governors
   i. Regulation Speed of Governor(RASH)
   ii. Normal starting speed
   iii. Emergency starting Speed
   iv. Water Inertia Time constant (T_W)

Structural diagram of Regulation System and a structural scheme of Governor showing transmitting functions of special elements recommended by IEEE.

6. **Thermal Plants**

a) General
   1. Detailed Report of the Project
   2. Status Report
      i. Land
      ii. Fuel supply
      iii. Water
      iv. Environmental Impact
   3. Technical and Economic Approval by respective Authorities according to Legislation in force.

b) Connection
   1. Report of studieson parallel functioningwiththeTransmission System.
      i. Load flow studies
      ii. Short Circuit studies
      iii. Staticand Dynamic Stability Studies
   2. Proposal for Connection with the Transmission System
      i. Number of lines
      ii. Voltage
      iii. Connection point/s

7. **Hydropower Plants**

   1. General
      1. Detailed Report of the Project
      2. Report of the Situation
         i. Topological Survey
         ii. Geographic Survey
         iii. Land
         iv. Environmental Impact
      3. Technical and Economic Approval by respective Authorities according to Legislation in force.
   2. Connection to transmission system network
      1. Report of studies on parallel functioning with the Transmission System
         i. Power flow studies
         ii. Short Circuit studies
         iii. Staticand Dynamic Stability Studies
      2. Proposal for Connection to the Transmission System
         i. Number of lines
         ii. Voltage
         iii. Connection point/s

8. **Data submitted by all types of Generating Plants**

a) Data on the maximal Current value of three and single phase short Circuit infed by the plant in the connection point to theTransmission System.

A.5 Detailed Data of the Transmission System

1. **General**

a) Single line diagram of the Transmission System that indicates connection points of generation plants
b) Transmission System Map showing connection points of generation plants
c) Substation name
d) Substations (for Plants and Transmission System) as follows:

1. Connected power plants
2. Transformers/Autotransformers
3. Substation Busbars
4. Commuting equipment with respective nomination (such as line exit, transformer exit,etc.)
5. Equipment for Reactive Power Compensation

e) Number,length and parameters of lines

2. **Connection**

a) Detailed Report of the Project
b) Report on the Situation

1. Route Survey-Lines
2. Land Survey-Substations
3. Environmental Impact

c. Technical and Economic Approval by respective Authorities according to Legislation in force.

3. **Line Parameter details:**

a) Name of the Line
b) Line Length (KM)
c) Number of circuits
d) Transmitting capacity for each circuit
e) Voltage kV
f) Positive Phases equence reactance (pu on 100MVA) Xl
g) Positive Phase sequence resistance(pu on 100MVA) Rl
h) Positive Phase sequence susceptance(pu on100MVA) Bl
i) Zero Phase sequence reactance (pu on 100MVA) Xo
j) Zero Phase sequence resistance (pu on 100MVA) Ro
k) Zero Phase sequence susceptance(pu on 100MVA) Bo

4. **Transformers and Autotransformers Parameters (for all transformers and autotransformers)**

a) Nominal Power MVA
b) Windings Power MVA

c) Nominal Voltage kV
d) Winding nominal voltage kV
e) Vector Group
f) On Load losses in kW
g) Short circuit Voltage U_k in % (for HV/MV, MV/LV, HV/LV)
h) No load Losses P_0in kW
i) No load current I_0in %
j) Zero sequence reactance(pu on 100MVA)
k) Tapchange range(±%) and steps
l) Details of Tap changer.(OFF load/ONload)

5. **EquipmentDetails(for all Substations)**

a) Power Transformers/Autotransformers
b) Switchers, circuit breakers
c) Isolators
d) Current and Voltage Transformers

6. **Relay Protection:**

a) Details of Relay Protection installed for all transformers / autotransformers, their settings and level of coordination with other Users
b) Details of Relay Protection installed for all lines;
c) Their settings and level of coordination with other Users
d) Details of Electricity Metering

7. **System Studies:**

1. Power flow studies(Peak and Minimum of loads for maximal hydro and thermal generation)
2. Transient stability studies for single and three phase short circuits in ,lines, transformers,busbars and small simulations
3. Static and dynamic stability studies and definition of critical times.
4. Shortcircuit studies(threephase and single phase to earth)Three and single phase maximal values fed to the Connection point
5. Studies on Transmission Losses

A.6 Detailed System Data (Distribution System Operator and Clients)

1. **General**

a) Map of operation area of the Distribution System Operatorand Eligible Customers(in scales) (indicating all lines and substations that belong to the Distribution System Operator and Clients).
b) Single line diagram of the system/object of the Distribution System Operator and Clients (indicating lines from the connection point to the Transmission System, 110/35kV substations,35/10/6kV substations)etc.
c) Number and Name of line and substation
d) Monitoring of Losses in their system/objects

2. **Connection**
    a) Connection Points (Indicates details of existing Connection equipment)
    b) Metering details in Connection points
    c) Details of relay protection in Connection points
3. **Load**
    a) ConnecteLoad(Category), (Customer"s Details),Loads" Details)
    b) Daily graphic (for specific days of the year) of the Demand in each Substation of the Distribution System Operator and Clients

A.7 Data to be Submitted upon OST Request

1. General
    a) Detailed Project Report (For strengthening of the existing Users systems/objectsand construction ofnewones)
    b) Report on the Situation
    c) Load Forecast for next 2 years
    d) Single line diagram (indicating lines and new proposed substations)
    e) Cost analysis
2. Connection
    a) Connection Points of Applicants for Connection
        1. New
        2. Improvement of existing Connections
    b) Changesof relay protection or metering equipment in Connection points
3. Loads
    a) Load Details and forecasts for next 2 years
    b) Load distribution into substations planned (projected)for next 2 years.
    c) Details of main loads to be contracted for next 2 years.
4. Improvement of Users schemes that reduce losses in the Transmission System
    a) Presentation of evaluation of losses caused by Users in the Transmission

    System for next 5 years

    b) Short description of improved schemes to reduce Losses (presented in a report) by analyzing:
        1. New Lines
        2. Improvement of existing lines
        3. New Substations and improvement of the existing ones
        4. Load rearrangement
        5. Capacitors installation

Section 3 –Other Planning Data(to be provided by all Users)

A.8 Annual System Planning (to be provided by all Users)

1. Scope (describes working details in cluded in the annual plan)
2. Situation (continued from the previous year or a new work)
3. Expenditure Plan
4. Increase of Benefits
5. Generation System
   a) Capacity added
   b) Improvement of Parameters
6. Transmission System Operator, OST sh.a
   a) Stability Improvement
   b) Loss reduction
   c) Increase of power flow capability
7. Distribution System Operator and Clients
   a) Loss Reduction
   b) Improvement of voltage level
   c) Covering of load growth in the area

A. 9 Ten Year System Planning Data (to be provided by all Users)

1. Projection of works for the next 5 years
2. Actual situation and development

A. 10 Works in Progress Data (to be provided by all Users)

1. Report on works performed by Generating Plants connected to the Transmission System
2. Graphic on works performed in Distribution System Operator areas
3. Graphic on works performed in Clients areas

A. 11 Final Data (to be provided by all Users)

a) Final data represent the date of works termination and readiness to connect to the Transmission System of User's system/objects that in fluence the Transmission System operation (performance).

Annex B –Planning Criteria

B.1 Generation Planning Criteria

Load Peak Participation Capacity (max load)

a) The possibility of participation of each Hydro Power plant in the peak load is the maximal power that may generate during peak hours.
   1. If it is a run-of-river plant the power production should be with 90% hydrological security
   2. If it is a reservoir (lake) plant the power production shal ldepend on the reservoir level and hydrological conditions

3. For thermal plants,the participation capacity during the peak is the maximal net power (without auxiliaries)

b) For new thermal units, the participating capacity during the peak should be assessed as 86% of installed capacity.This allows the use of approximately 10% for auxiliary consumption, and 4% for transformer losses assessed according to installed capacity of the unit.

Planning Criteria of Regulation Reserves

The regulating reserves FCR,FRR,RR are described in the Code.

Power Planning Criteria

Reserved Energy shall not pass 0.15% of the annual average energy according to Operational Planning (up to 1 year).

Power Generation Planning

a) Annual Electricity estimated in a Hydro Power Plant is defined as potential Electricity generated by the Plant with 90%, 75% and 50% off low hydrological security.
b) For Thermal Power Plants,Electricity generated is estimated as the product of installed capacity for 4000-6000 working hours per year,according to the type of electric plant.
c) for RES generators, wind and photovoltaic generated electricity,estimated energy is the product of installed capacity for 200-2800 hours a year, according to the types of energy power generators.

B. **2 Transmission System Planning Criteria**

Objectives

1. TheTransmission System shall be planned to operate reliable and safe, and efficiently for all Users in order to guarantee uninterrupted electricity supply with acceptable levels of voltage and frequency according to criteria described by this Code.

2. **(n-1)Criteria ofTransmission System Planning**

a) For the Transmission System Planning the **(n-1)**criterion is applied.**(n-1)** criterion is used to:
   1. Asses the level of Transmission System use by Users in the existing and future conditions
   2. Assess the load that should be limited in the existing situation based on operating conditions of the Electric Power System
   3. Assess Transmission System voltage levels
   4. Prepare Transmission System Development Scheduling
   5. Assess operation safety

b) **(n-1)**criterion is applied for regimes with programmed maximal loads as follows:

1. For 400kV,220kV lines **(n-1)** criteria is used to define the conductor section of Transmission System lines for the current passing in each line of the system referring to a basic operating regime, which doesn"t consider an unplanned outage of the biggest generating units
2. For 110kV lines, **(n-1)** criteria is applied
    i. closing all 110kV rings.
    ii. Disclosing all 110kV lines that work in parallel with 400kV and 220 kV lines.

3. Technical criteria to check up the Transmission System planning regarding the Stability

a) The technical criteria to verify the static and dynamic stability of power system and the Transmission System performance, takes in consideration:
    1. maximal load regimes
    2. 2 year verification period
    3. A list of simulations prepared based on experience

4. **Technical criteria to dimension the reactive power compensation installations**

a) Establishing of installation for reactive power generation/absorbing is performed by analyzing the voltage levels in all nodes of the Transmission System and in all operation regimes with **(n)** and **(n-1)** configuration.
b) For the 400kV rated voltage in the Transmission System, the voltage range allowed by a**(n)** and **(n-1)**configuration is 360-420kV.
c) For the 220kV rated voltage in the Transmission System,the voltage range allowed by a**(n)** and **(n-1)** configuration is 198-242kV.
d) For the 150kV rated voltage in the Transmission System,the voltage range allowed by a**(n)** and **(n-1)** configuration is 142,5 -162kV.
e) For the 110kV rated voltage in the Transmission System,the voltage range allowed by a**(n)** and **(n-1)** configuration is 99-123kV

The purpose of establishing of installations for reactive power generation/absorbing is to optimize the Transmission System operation in order to maintain the voltage within allowed levels and reduce transmission technical losses. For this scope,planning is extended to a 2 year period, evaluating the maximal and minimal load regimes of the system.

B. **3 References and Standards**

1. International standards shall be used to plan the Transmission System as follows:
    a) In designing,construction or modification of elements of the Transmission System (overhead lines, cablelines, conductors, transformers, autotransformers, commuting equipment (switchers, circuit breakers) chargers),etc
    b) In designing, construction or modification of Users systems/objects
2. Criterions of Transmission Projection:

a) Transmission System Lines should be projected as far as possible double circuit lines
b) Existing single circuit lines if it is possible to be reinforced by another circuit
c) The selected line route should be as optimal as possible regarding the passing territory
d) Projection and construction of lines should be according to International Standards and effective Legislation
e) The Transmission System should provide an integrated function of SEE for all optional situations

f) Capacities of the Transmission System are evaluated by OST time after time with studies on:
    i. Load flow studies
    ii. Short Circuit studies
    iii. Static and Dynamic Stability Studies

g) Studies shall be performed under the following regimes to evaluate if the Transmission System is operating according to safety criteria:
  1. The system that shall be planned to maintain the voltage and eliminate overload for **(n)** and **(n-1)** criteria. **(n-1)** criteria shall be applied to switching off generating units, transformersor transmission lines.
  2. The peak load shall be covered in two cases:
      i. Minimal Thermal Plants generation
      ii. Minimal Hydro Plants generation

h) The optimum of Transmission System reactive compensation shall be established by studies identifying and metering the current in lines and loads under transformation,in order to define voltage levels during the peak load. Capacitors should be of the regulated type in order to avoid overvoltages.

i) The relay protection should be projected to eliminate the faults within the following periods:
    1. 80 millisecond for400 kV elements
    2. 110 millisecond for220 kV elements
    3. 120 millisecond for110 kV elements

j) Dynamic and transient overvoltage studies shall be carried out on 400kV, 220kV and 110 kV lines to ensure that the power frequency and switching surge overvoltages do not exceed the acceptable values for the insulation level of equipment and protective devices.

5. <u>Substation Projection Criteria</u>

a) Substations shall be designed by taking in consideration the following factors:
    1. Desired degree of flexibility
    2. Facility of operation and maintenance
    3. Safety of operating and maintenance staff
    4. Provision of spare Bays or space for future expansion
    5. Safety guarantee of operative staff and equipment to prevent wrong functioning of electric equipment
    6. Appropriate equipment to isolate and put out the fire according to Legislation in force,in order to guarantee the staff safety and avoid equipment damages
    7. Earth connection of Substation should be in conformity to requirements and Standards.The Earthing System should be designed to have low overall impedance.The impedance shall not exceed four ohm (4Ω). The step and touch voltage should be within safety limits.

B. **4 Distribution System Operator and Clients systems/objects**

1. Distribution System Operator systems/objects are connected to the Transmission System in 110kV of voltage level.

2. Users that own,operate and maintain the Distribution System for 110/MVkV substations follow the designing criteria established by the Grid Code, and the Distribution Code criteria for the rest.

Annex C – Protection Data

These data are presented in the following table:

Issues	To be submitted
Users should submit details of relay protection requirements and installed schemes as described in Annex A Part 2	As applicable to Detailed Planning Data
The OST shall submit details of protection equipment and schemes installed by them as referred to in Appendix A, Part 2	As applicable to Detailed Planning Data

Annex D – Reporting of Events with Incident

REPORTING NUMBER ………… Place ……Date …………. Hour ………….

Date and hour of event with incident ………………

Place of event with incident ……………………….

Type of event with incident ……………………….

Power System parameters before event with incident …………………………………………………………….

Power System parameters after the event with incident ………………………………………………………….

Parameters and Configuration of Network before the event with incident ……………………………….

Indications of Relay Protection Devices and their performance ……………………………………………….

Damaged equipment ………

Undertaken repairing operative actions ………………………………………………………………………………

Supply interruption and time period ……………………………………………………………………………………

Cause of event with incident ……………………………………………………………………………………………

Recommendations for future improvements in case of repeating of the event with incident ……

Names and Signatures of Responsible Operative Staff

……………………………………………………………………….

Annex E –Investigation of Event with Incident

1. The scope of investigation is to enable OST to provide information related to equipment and operative procedures.
2. In order to argue and draw conclusions on the incident, OST shall send its representatives to the Transmission grid User to investigate operative procedures including but without limiting to the investigation of:
   a) Execution of orders issued by the National Dispatch Center
   b) Compliance of Users" operative orders with operative orders issued by the System Operator.
3. The investigation may be based only on operational issues of the Power System, but if it is necessary and essential, the investigation may be extended in time and analyzed seeing through the other elements, recording and decoding equipment of OST's and User's SCADA installations.
4. Users should accept and provide to OST representatives all necessary documents.
5. The investigation procedure is established by OST

Under frequency Load Shedding Structure – SHAF-1

SHAF-1			
Step	**Frequency**	**%of load shedding**	**Time Delay**
1	49.0 Hz	10%	0.2 sec
2	48.8 Hz	15%	0.2 sec
3	48.2 Hz	15%	0.5 sec
3	47.8 Hz	15%	0.5 sec

SHAF-2						
Hz Type	**Gradient (Hz/sec)**	**49.0 Hz**	**48.8 Hz**	**48.2 Hz**	**47.8 Hz**	**% of total load**
Quantity of Switched off Load %						
49.0	-0.8	17.77%	7.17%	-	-	2.85
49.0	-1.0	22.65%	10.43%	15.93%	-	6.22
49.0	-1.7	-	12.80%	16.97%	25.90%	8.35
49.0	-2.0	-	10.43%	25.69%	39.70%	11.37
Total	**-**	**40.42%**	**40.83%**	**58.60%**	**65.60%**	**28.8**

References

Law no. 43/2015 "On Power Sector"
Commission Regulation (EU) 2016/631of 14 April 2016 for establishing a network code on requirements for grid connection of generators
http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32016R0631&from=EN
Network Code on Demand Connection (21/12/2012)
https://ec.europa.eu/energy/sites/ener/files/documents/DCC_161015_Final_Provisional_Voted.pdf
[NC OS] Kodi i rrjetit ENTSO-E Për Sigurinë Operacionale (24/09/2013)

https://www.entsoe.eu/fileadmin/user_upload/_library/resources/OS_NC/130924-AS NC_OS_2nd_Edition_final.pdf
[NC OP&S] Network Code on Operational Planning and Scheduling (24/09/2013)
https://www.entsoe.eu/fileadmin/user_upload/_library/resources/OPS_NC/130924-AS_NC_OPS_2nd_Edition_final.pdf
Commission Regulation (EU) 2015/1222 of 24 July 2015 for establishing a guideline on capacity allocation and congestion management
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ENTSO-E Transparency Platform (https://transparency.entsoe.eu/)