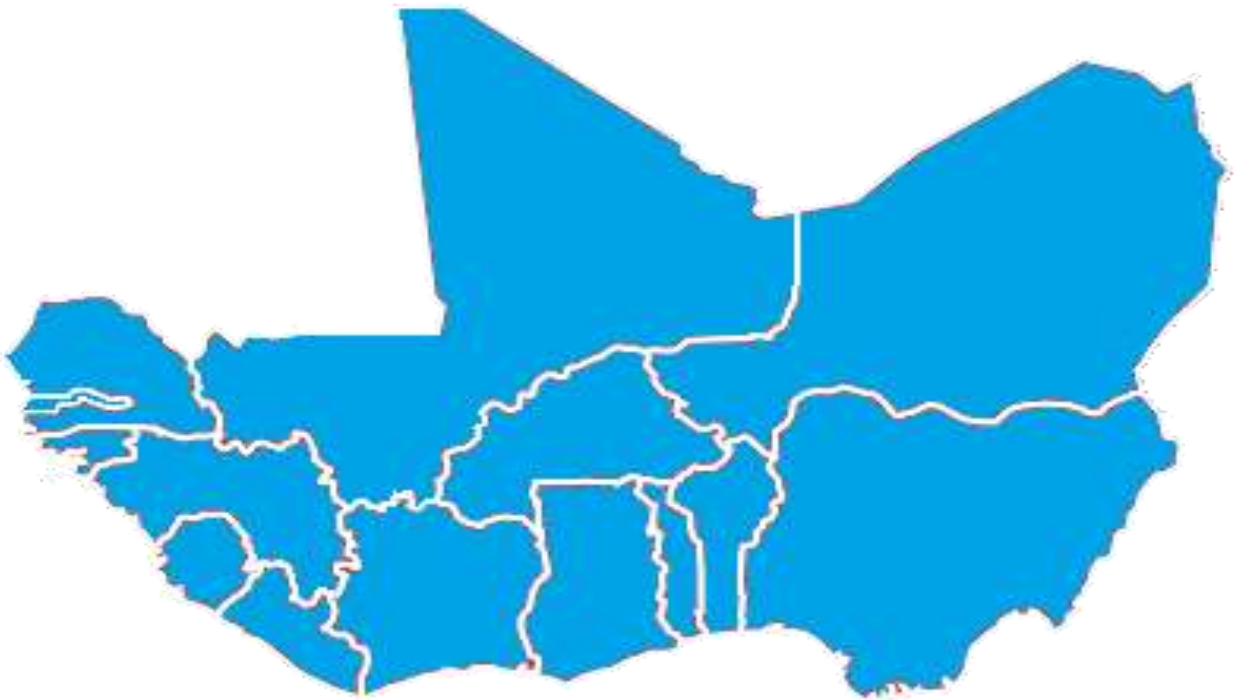




REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA

REMC-WA

V1.0 - SEPTEMBER 2025

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA

REMC-WA

- ☐ RESOLUTION No.018/ERERA/25
- ☐ GLOSSARY AND DEFINITIONS (GD)
- ☐ GENERAL CONDITIONS (GC)
- ☐ PLANNING CODE (PC)
- ☐ OPERATION CODE (OC)
- ☐ CONNECTION CODE (CC)
- ☐ MARKET CODE (MC)
- ☐ METERING CODE (MTC)
- ☐ OPERATORS' TRAINING CODE (OpTC)

REGIONAL AUTHORITY
ECOWAS ELECTRICITY REGULATOR

ECOWAS REGIONAL
ELECTRICITY
REGULATORY AUTHORITY



REGULATORY AUTHORITY
REGIONAL SECTOR OF
ECOWAS ELECTRICITY

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RESOLUTION No. 018/ERERA/25
Approval of the Regional Electricity Market Codes of West Africa
(REMC-WA)

The Regulatory Council,

MINDFUL of the Supplementary Act A/SA.2/01/08 of 18 January 2008 establishing the ECOWAS Regional Electricity Regulatory Authority (ERERA);

MINDFUL of Regulation C/REG.27/12/07 of 15 December 2007 as amended, on the composition, organization, functions and operation of ERERA, in particular Articles 18.2(b) and 18.3(c) thereof;

MINDFUL of Directive C/DIR.1/06/13 of 21 June 2013 on the organisation of the regional electricity market;

MINDFUL of the Regional Market Rules for the West African Power Exchange System (WAPP) approved by Resolution No. 005/ERERA/15, in particular Article 39 thereof.

HAVING REGARD to the letter ref.: WAPP/2023/SG/DICC/ ja /mm/ria/019 of 26 January 2023 from the WAPP General Secretariat transmitting to ERERA, for adoption, the WAPP Grid Code.

CONSIDERING the report of the twenty-third joint meeting of the Consultative Committees of Regulators and Operators of ERERA of 23 July 2024 recommending the adoption of the WAPP Grid Code by ERERA's Regulatory Council,

CONSIDERING the minutes of the eighty-ninth meeting of ERERA's Regulatory Council held on 13 September 2025 which examined the draft WAPP Grid Code and entitled it "Regional Electricity Market Codes of West Africa" (REMC-WA),

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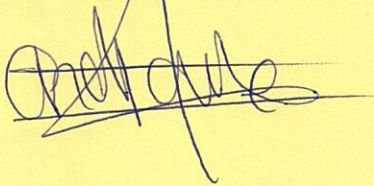
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RESOLVED THAT

1. The Regional Electricity Market Codes of West Africa (REMC-WA), hereby attached, are approved by the Regulatory Council.
2. Any provisions of the previous Resolutions of the Regulatory Council contrary to this Resolution are repealed, notably those of Resolutions No. 5, No. 7, No. 10 and No. 14.
3. The Regional Electricity Market Codes of West Africa (REMC-WA) will be published in the Official Bulletin and on the ERERA website.

Done at Tutu Akwapem, GHANA, on September 13, 2025

Charles NDIAYE



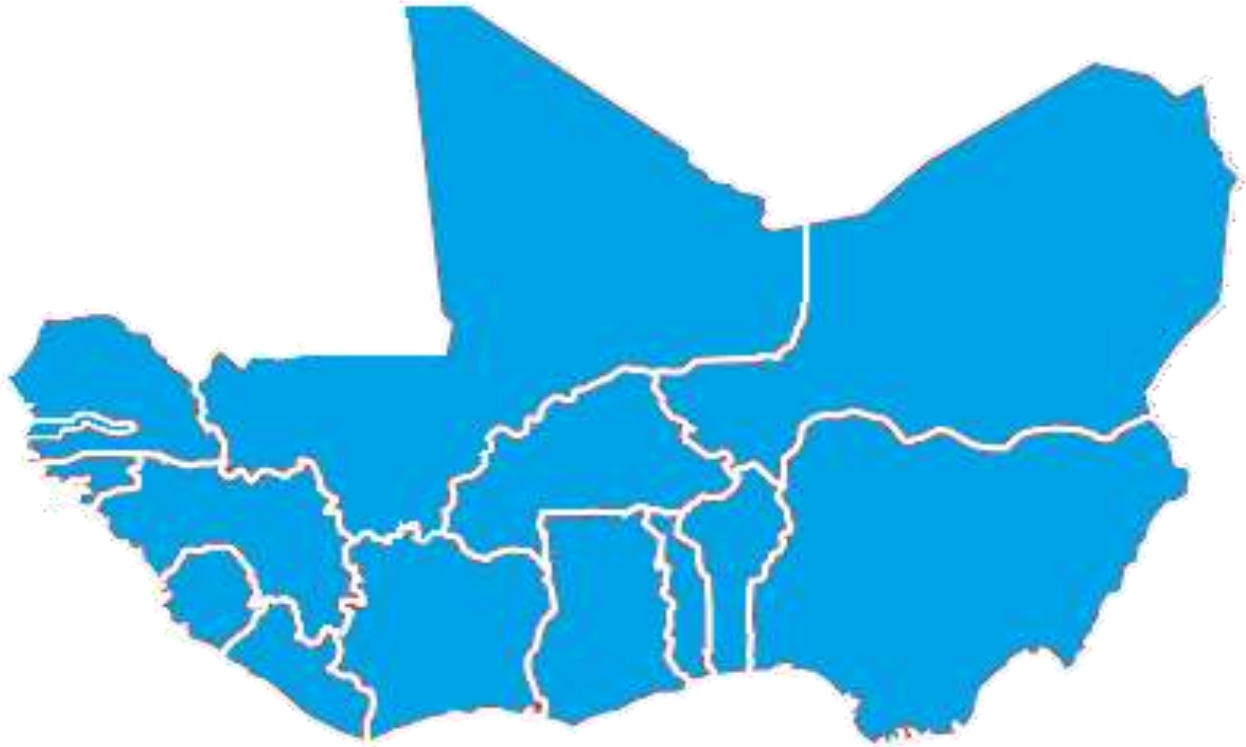
Council MEMBER, Legal

Kocou Laurent Rodrigue Tossou



Chairman

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



GD – GLOSSARY AND DEFINITIONS

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GD 1. TERMS AND DEFINITIONS

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Abuse of Dominant Position		as defined in MC 21.2.7	1	Abus de position dominante		tel que défini dans le MC 21.2.7
ACE Average Zero Crossing Period		Average time interval between two (2) consecutive zero crossings of ACE of an LFC Area.	2	Période moyenne de passage à zéro de l'erreur de contrôle de zone (ACE)		Intervalle de temps moyen entre deux (2) passages à zéro consécutifs de l'ACE d'une Zone LFC.
Addendum to the Inter-Grid Operators Agreement		means, within the Transitional Provisions Framework, the binding document where each Grid Operator arranges to list the Grid Operator Non-compliances (if any) at the moment of approval of the REM Codes and to provide a roadmap to solve them. The Addendum to the Inter-Grid Operators Agreement also entails actions aimed at adapting national regulations to the provisions of the REM Codes.	3	Addendum à l'Accord inter-Gestionnaire de réseau		signifie, dans le Cadre des dispositions transitoires, le document contraignant en vertu duquel chaque Gestionnaire de réseau prend des dispositions pour répertorier les Non-conformités des Gestionnaires de réseau (le cas échéant) au moment de l'approbation des Codes du MRE et met en place une feuille de route pour les résoudre. L'Addendum à l'Accord inter-Gestionnaire de réseau comporte également des actions visant à adapter les réglementations nationales aux dispositions des Codes du MRE.
Adequacy		means the ability of the Power System to always meet the Demand, taking into consideration Planned Outages and/or Forced Outages (as defined in OC 6.6 of the Operation Code)	4	Adéquation		désigne la capacité du Système Electrique à satisfaire à tout moment la Demande en prenant en compte les Indisponibilités planifiées et/ou les Indisponibilités fortuites. (Tel que défini dans OC6.6 du Code d'exploitation.)
Adequacy Assessments		it has the meaning given to it in OC 6.6 of the Operation Code.	5	Évaluations de l'adéquation		a la signification décrite dans le OC 6.6 du Code d'exploitation.
Aggregated Netted Grid Operator External Schedule		means a schedule representing the netted aggregation of all Grid Operator External Schedules between two (2) Scheduling Areas or between a Scheduling Area and a group of other Scheduling Areas.	6	Programme net externe agrégé des Gestionnaires de réseau		désigne un programme représentant l'agrégation nette de tous les programmes externes de Gestionnaire de réseau entre deux (2) zones de programmation ou entre une zone de programmation et un groupe d'autres zones de programmation.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Agreement Process		means the process where both the importing and exporting Grid Operators confirm the values of Grid Operator External Schedules for a given direction and for all time intervals in each time frame.	7	Processus d'accord		désigne le processus au cours duquel les Gestionnaires de réseau importateur et exportateur confirment les Programmes externes de Gestionnaire de réseau pour tous les intervalles de temps de chaque échéance.
Alert State		it has the meaning given to it in OC 3.4.3 of the Operation Code.	8	État d'alerte		a la signification décrite dans le OC 3.4.3 du Code d'exploitation.
Allocation Mechanism		means the allocation of capacity in the OTC market determined by regulatory-driven allocation or by the First-Come First-Served or Explicit Auction mechanisms.	9	Mécanisme d'allocation		désigne l'attribution de la capacité dans le Marché OTC, déterminée par allocation par réglementation ou par le mécanisme du « Premier venu-premier servi » ou par des Enchères explicites.
Already Allocated Capacity	AAC	means the total amount [MW] of allocated transmission rights, whether they are capacity or exchange programs depending on the allocation methods.	10	Capacité déjà allouée	AAC	désigne la quantité totale [MW] des droits de transport alloués, qu'il s'agisse de programmes de capacité ou d'échange, selon les modalités d'allocation.
Alternating Current	AC	means electric current that is a periodic function of time with a zero direct component or, by extension, a negligible direct component.	11	Courant Alternatif	CA	désigne le courant électrique qui est une fonction périodique du temps avec composante directe nulle ou, par extension, composante directe négligeable.
Ancillary Service		means a service other than the production of energy and/or provision of capacity, which is used to maintain reliability including reserves, frequency control, voltage control and Black Start Capability.	12	Service système		désigne un service autre que la production d'énergie et/ou la fourniture de capacité, utilisé pour maintenir la fiabilité, y compris les réserves, le contrôle de la fréquence, le contrôle de la tension et la Capacité de démarrage autonome.
Annual Maintenance Period	AMP	means the period(s) in the year where maintenance activities are conveniently undertaken.	13	Période de maintenance annuelle	PMA	désigne une des périodes de l'année au cours de laquelle il convient de réaliser des activités de maintenance.
Annual Operation Report		means the yearly report published in year Y on the facts and figures of the operation of the year Y-1.	14	Rapport annuel d'exploitation		désigne le rapport annuel publié l'année A sur les faits et les chiffres de l'exploitation de l'année A-1.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Annual Unavailability Plan	AUP	means the yearly Unavailability Plan of each Grid Operator.	15	Plan d'indisponibilité annuel	PIA	désigne le calendrier annuel d'indisponibilité de chaque Gestionnaire de réseau.
Applicant		Any Entity applying for admission to the Regional Electricity Market as a Market Participant.	16	Candidat		toute Entité demandant à être admise au Marché régional de l'électricité en tant que Participant au marché.
Area Control Error	ACE	Refers to the sum of the power control error (' ΔP '), that is the real-time difference between the measured actual real-time power interchange value ('P') and the Control Area Program ('P0') of a specific LFC Area or LFC block and the frequency control error (' $K \cdot \Delta f$ '), that is the product of the K-Factor and the frequency deviation of that specific LFC Area or LFC block, where the area control error equals $\Delta P + K \cdot \Delta f$.	17	Écart de réglage de zone	ACE	fait référence à la somme de l'écart de réglage de puissance (ΔP), c'est-à-dire la différence en temps réel entre la valeur d'échange de puissance réelle et mesurée en temps réel (P) et le Programme de Zone de réglage (P0) d'une Zone LFC spécifique ou bloc LFC et l'écart de réglage de fréquence ($K \cdot \Delta f$), c'est-à-dire le produit du facteur K et de l'écart de fréquence de la Zone LFC ou bloc LFC donné(e), où l'Écart de réglage de zone est égal à $\Delta P + K \cdot \Delta f$.
Asynchronous Area		means a portion of the WAPP Power System that is operated by national Grid Operators that are not synchronously interconnected.	18	Zone asynchrone		désigne une partie du Système électrique de l'EEEOA exploitée par des Gestionnaires de réseau nationaux non interconnectés de manière synchrone.
Auction Bid		means an Offer placed by a Market Participant to purchase PTRs, submitted in an Explicit Auction pursuant to and in compliance with the Market Code; such an Offer consists of two (2) values: capacity in a direction, and Bid Price i.e., a requested Capacity over each hour of the period (bid quantity) in MW and a Bid Price in USD per MW per hour.	19	Enchère		désigne une offre placée par un Participant au marché pour l'achat de PTR, soumise dans le cadre d'une Enchère explicite conformément au Code du marché; une telle offre se compose de deux (2) valeurs: la capacité dans un sens du transit et le prix de l'offre, c'est-à-dire, une capacité demandée sur chaque heure de la période (quantité offre) en MW et un prix de l'offre en USD par MW par heure.
Auction Clearing Price		means the price of the last MW allocated by an Explicit Auction due to insufficient offered capacity, which represents the marginal price on the congested Cross-Border Interconnection to be paid by the Market Participants for each MW and hour of acquired PTRs in that period.	20	Prix d'équilibre de l'enchère		désigne le prix du dernier MW attribué par une Enchère explicite en raison d'une capacité offerte insuffisante, qui représente le prix marginal sur l'Interconnexion transfrontalière congestionnée à payer par les Participants au marché pour chaque MW et heure de PTR acquis au cours de cette période.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Auction Tool		means electronic internet-based auction platform used by SMO to conduct Explicit Auctions.	21	Outil d'enchère		désigne une plate-forme électronique d'enchères sur internet, utilisée par l'OSM pour mener les Enchères explicites.
Automated Meter Reading System	AMR	means the facilities required to perform the process of remote collection of the readings and Metering Data from a Metering Equipment and transferring such readings and Metering Data into a remote Metering Database.	22	Système de lecture automatique des Compteurs	AMR	désigne les installations nécessaires au processus de collecte à distance des relevés et des Données de comptage d'un Equipement de comptage et le transfert de ces Données de comptage dans une Base de données de comptage située à distance.
Automatic Generation Control	AGC	means an equipment for automatically adjusting the power output of multiple Generation Units at different Generation Facilities, in response to changes in the Demand. AGC automatically adjusts the Generation to maintain its Generation dispatch, interchange schedule plus its share of frequency regulation. AGC is a combination of LFC and real-time Operation of the Generation dispatch function (based on Generation scheduling).	23	Réglage automatique de la production	AGC	désigne un système permettant de régler la puissance de sortie de plusieurs Unités de production dans différentes Installations de production, en réponse aux changements de la charge ou consommation. L'AGC ajuste automatiquement la Production pour maintenir sa répartition de la production, son programme d'échange ainsi que sa part de régulation de fréquence. L'AGC est une combinaison de LFC et d'exploitation en temps réel de la fonction de répartition de la production (basée sur la programmation de la Production).
Automatic Voltage Regulator	AVR	means the continuously acting automatic equipment controlling the terminal voltage of a Synchronous Generation Unit by comparing the actual terminal voltage with a reference value and controlling the output of an excitation control system.	24	Régulateur automatique de tension	AVR	désigne l'équipement automatique à action continue contrôlant la tension de sortie d'une Unité de production synchrone en comparant la tension terminale réelle à une valeur de référence, et en contrôlant la sortie d'un système de contrôle d'excitation.
Available Transfer Capacity	ATC	means the portion of NTC that remains available for future allocations. ATC is expressed as follows: $ATC = NTC - AAC$. Therefore, whenever any of these terms are used further in the text the following equation should be borne in mind: $ATC = TTC - TRM - AAC$.	25	Capacité disponible de transfert	ATC	désigne la part de NTC qui reste disponible pour les allocations futures. La valeur ATC est exprimée comme suit : $ATC = NTC - AAC$. Par conséquent, chaque fois que l'un de ces termes est mentionné plus avant dans le texte, l'équation suivante doit être gardée à l'esprit : $ATC = TTC - TRM - AAC$.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Average Network Power Frequency Characteristic		Network Power Frequency Characteristic (in MW/Hz) calculated in average over a given validity period.	26	Energie réglante moyenne de réseau		Energie réglante du réseau (en MW/Hz), calculée en moyenne sur une période de validité donnée.
Base Case		means set of data, common for all Grid Operators, used for Grid analysis and needed to simulate cross-border electricity exchanges. The set of data includes, for a certain point in time, the expected Operating Conditions of the whole Power System, with the Common Grid Model and input data describing Demand and Generation patterns forecast and Grid topology at the study time frame (yearly, monthly, weekly and daily).	27	Cas de base		désigne un ensemble de données, communes à tous les Gestionnaires de réseau, utilisées pour l'analyse du réseau de transport et nécessaires pour simuler les échanges d'électricité transfrontaliers. Cet ensemble de données comprend, pour un point horaire donné, les conditions d'exploitation attendues de l'ensemble du Système électrique, avec le Modèle de réseau commun et les données d'entrée décrivant les modèles de charge ou consommation et de production prévus, et la topologie du réseau de transport, durant l'étude (annuelle, mensuelle, hebdomadaire et journalière).
Base Case Exchange	BCE	means the initial exchange between two (2) transaction areas before applying any additional power shift	28	Cas de base d'échange	BCE	désigne la valeur initiale des échanges entre deux (2) zones de transaction avant toute simulation d'augmentation de puissance.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Best Effort		means, for any action required to be made, attempted or taken by a Party, all necessary efforts that a prudent Entity would or ought to undertake to protect its own interests, including commercial interests, taking into account the conditions affecting such action, including the amount of notice to act, recognition of the need to act, the duration and type of the action, the competitive environment in which such action occurs, and the projected benefit, cost and risk to the Party required to take such action; provided, however, Best Efforts shall always be interpreted to take into consideration the rights and obligations of the Parties under the REM Codes and the relevant Grandfathered Agreements.	29	Meilleur effort		désigne, pour toute action devant être entreprise, tentée ou prise par une Partie, tous les efforts nécessaires qu'une Entité prudente ferait ou devrait faire pour protéger ses propres intérêts, y compris les intérêts commerciaux, compte tenu des conditions affectant une telle action, le délai de préavis pour agir, la reconnaissance de la nécessité d'agir, la durée et le type de l'action, l'environnement concurrentiel dans lequel une telle action se produit, et les avantages, coûts et risques prévus pour la Partie tenue d'entreprendre une telle action; tout cela à condition toutefois que les meilleurs efforts soient toujours interprétés comme prenant en considération les droits et obligations des Parties en vertu des Codes du MRE et des contrats avec droits acquis pertinents.
Bid		It is a submission of a proposal (price and quantity) by a Market Participant to buy energy in the Day-Ahead Market.	30	Offre d'achat		désigne la soumission d'une proposition d'achat (prix et quantité) par un Participant au marché pour acheter de l'énergie sur le Marché du jour pour le lendemain.
Bid Price		means the highest price which a Market Participant is willing to pay for 1 MW of requested Capacity per hour.	31	Prix de l'offre d'achat		désigne le prix le plus élevé qu'un Participant au marché est prêt à payer pour 1 MW de capacité demandée par heure.
Bilateral Contract		Agreement entered between a Buyer and Seller of electricity for the sale and purchase of electricity in a Cross-Border Transaction under the OTC Market. The Seller agrees to inject, and the Buyer agrees to extract the agreed upon volume of electricity in the relevant Trading Interval or Trading Intervals for a price mutually agreed.	32	Contrat bilatéral		Accord conclu entre un Acheteur et un Vendeur d'électricité pour la vente et l'achat d'électricité dans une Transaction transfrontalière sur le Marché OTC. Le Vendeur accepte d'injecter, et l'Acheteur accepte de soutirer le volume d'électricité conformément au prix contractuel convenu pour l'Intervalle de négoce ou les Intervalles de négoce concernés.
Bilateral Data Exchange		Data Exchange between two (2) Parties only.	33	Échange de données bilatéral		Échange de données entre deux (2) Parties uniquement.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Black Start Capability		means the capability of a Generation Facility to start without an external electrical supply to be used to energize a defined portion of the Grid.	34	Capacité de démarrage autonome		désigne la capacité d'une Installation de production à démarrer sans alimentation électrique extérieure pour l'alimentation d'une partie définie du Réseau de transport.
Blackout State		it has the meaning given to it in OC 3.4.7 of the Operation Code.	35	État de panne généralisée (black-out)		a la signification décrite dans le OC 3.4.7 du Code d'exploitation.
Block Order		as defined in MC 13.1.2.1 b)	36	Offre en bloc		tel que défini dans le MC 13.1.2.1 b)
Buyer		A Market Participant that purchases electricity in the Regional Electricity Market.	37	Acheteur		Un Participant au marché qui achète de l'électricité dans le Marché régional d'électricité.
Capacity Hoarding		as defined in MC 21.2.8	38	Accumulation de capacités		tel que défini dans le MC 21.2.8
Cartelization		as defined in MC 21.2.2	39	Cartellisation		tel que défini dans le MC 21.2.2
Central Database		it has the meaning given to it in PC 3.1 of the Planning Code.	40	Base de données centrale		a la signification qui est décrite dans le PC 3.1 du Code de Planification.
Certified Trader		it is a person or Entity acting on behalf of the Market Participant for trading in the REM.	41	Négociant certifié		désigne une personne ou d'une Entité agissant pour le compte du Participant au marché pour le négoce dans le MRE.
Check Meter		means a Meter used for validation and/or estimation for Settlement purposes in accordance with the process used to validate, estimate, and/or edit raw Metering Data to produce final Metering Data or to replicate missing Metering Data.	42	Compteur de vérification		désigne un Compteur utilisé pour la validation et/ou l'estimation à des fins de règlement, conformément au processus utilisé pour valider, estimer et/ou modifier les Données de comptage brutes pour produire des Données de comptage définitives ou pour reproduire les Données de comptage manquantes.
Circular Trading		as defined in MC 21.2.6	43	Commerce circulaire		tel que défini dans le MC 21.2.6
Clearing		means the process by which Offers and Bids are matched and prices are determined for the next Delivery Day.	44	Compensation		désigne le processus par lequel les Offres de vente et les Offres d'achat sont mises en correspondance et les prix sont déterminés pour le Jour de livraison suivant.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Clearing House		is an Entity approved by ERERA to facilitate the exchange of payments, securities, or transactions. The Clearing House stands between two (2) Parties. Its purpose is to reduce the risk of a Party failing to honour its trade settlement obligations.	45	Chambre de compensation		est une Entité agréée par l'ARREC pour faciliter l'échange de paiements, de titres ou de transactions. La Chambre de compensation se situe entre deux (2) Parties. Son objectif est de réduire le risque qu'une Partie n'honore pas ses obligations en matière de règlement des transactions.
Codes of Practice		means a document that complements laws and regulations and provide detailed practical guidance on how to comply with statutory, regulatory and legal obligations and should be followed unless another solution with the same or better result is in place. Commonly developed and agreed Codes of Practice are advised to be derived and supported across the Member States.	46	Codes de pratique		désigne un document venant compléter les lois et règlements avec des conseils pratiques détaillés sur la manière de se conformer aux obligations légales contraignantes, à moins qu'une solution alternative présentant la même ou une meilleure efficacité ne soit en place. Il est recommandé que les Codes de pratique élaborés et approuvés en commun soient élaborés et soutenus par tous les États membres.
Cold Standby Reserve		means the Reserve capacity from Generation Units or equivalent power resources, which is available for service and ready for loading	47	Réserve froide		désigne la capacité de réserve des Unités de production ou sources de production équivalentes, qui sont disponibles pour le service et prêtes à être chargées
Collateral		means a Credit Support in the form of a Bank Guarantee issued by a bank on behalf of a Market Participant, which shall be forfeited to the SMO in the event that the Market Participant fails to meet its payment obligations in the OTC Market, the Day-Ahead Market (DAM), or in transactions arising therefrom, in accordance with the provisions of the Market Code	48	Garantie financière		cela se réfère à un Soutien au crédit sous la forme d'une garantie émise par une banque pour le compte d'un Participant au marché, lequel peut être exécuté au profit de l'OSM en cas de manquement du Participant au marché à ses obligations de paiement sur le Marché OTC, dans le Marché du jour pour le lendemain (DAM) ou dans le cadre des transactions qui en découlent conformément aux dispositions du Code du marché.
Commercial Metering Point		means, the physical location at which the electricity is metered.	49	Point de mesure commercial		désigne l'emplacement physique où l'électricité est mesurée.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Common Grid Model		Region-wide data set agreed among Grid Operators describing the relevant characteristics of the WAPP Power System (Generation, Demand and Relevant Grid topology) and rules for changing these characteristics during the NTC calculation process, in a way that flows on the tie lines are consistent with the cross-border electricity exchanges.	50	Modèle de réseau commun		Ensemble de données régionales convenues entre les Gestionnaires de réseau, avec description des caractéristiques pertinentes du Système électrique de l'EEEOA (production, consommation et topologie du Réseau de transport pertinent) et les règles pour modifier ces caractéristiques au cours du processus de calcul de la NTC pour que le flux sur les lignes de raccordement soit cohérent avec les échanges d'électricité transfrontaliers.
Common Information		Data set resulting from merging or aggregating shared Individual Information and all derived data.	51	Informations communes		Ensemble de données issues de la fusion ou de l'agrégation des informations individuelles partagées et de toutes les données dérivées.
Compensation Program		means the compensation of unintentional deviations from a schedule. It is performed by exporting to/ importing from the interconnected Power System during the compensation period by means of schedules of constant power within the same tariff periods as when they occurred.	52	Programme de compensation		désigne la compensation des écarts fortuits par rapport à une planification. Elle est effectuée en exportant vers (en important depuis) le Système électrique interconnecté pendant la période de compensation par des programmes de puissance constante dans les mêmes périodes tarifaires que lors de leur survenue.
Compensation Program Schedule		means a schedule representing the exchange of electricity of Grid Operators related to a Compensation Program.	53	Calendrier du programme de compensation		désigne un calendrier représentant l'échange d'électricité des Gestionnaires de réseau en relation avec un Programme de compensation.
Compliance Continuous Monitoring		means, within the Transitional Provisions Framework, the process of monitoring and evaluation of the progress of each Member State according to the related Addendum to the Inter-Grid Operators Agreement.	54	Gestion continue de la conformité		désigne, dans le Cadre des dispositions transitoires, le processus de suivi et d'évaluation des progrès de chaque État membre conformément à l'Addendum à l'Accord inter-Gestionnaire de réseau.
Compliance Evaluation Group		means the working group led and organized by the WAPP, which is in charge to lead the Compliance Continuous Monitoring process.	55	Groupe d'évaluation de la conformité		désigne le groupe de travail dirigé et organisé par l'EEEOA, responsable de la gestion du processus de la Gestion continue de la conformité.
Confidential Information or Confidential Data		As defined in GC 13 of the General Conditions.	56	Informations confidentielles ou Données confidentielles		tel que défini dans le point GC13 des Conditions générales.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Congestion		means a condition of the Transmission System or specific lines that prevents the expected flow of electricity and also prevents the market transactions being performed as scheduled, due to limitation in the equipment and Facilities.	57	Congestion		désigne une condition du Réseau de transport ou de lignes spécifiques qui empêche le flux attendu d'électricité et également les transactions sur le marché d'être effectuées comme prévu, en raison de limitations dans les équipements et les Installations.
Connected Microgrid		Microgrid that can be connected to the Network	58	Micro-réseau connecté		Micro-réseau pouvant être connecté au Réseau.
Connection Code	CC	means the section of the Regional Electricity Market Codes of West Africa that defines and governs the conditions for the access of Generation Facilities, Demand Facilities and HVDC Systems to the Grids of the Member States. The aim is to promote the correct functioning and safety of the WAPP Power System.	59	Code de raccordement	CC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain qui définit et gouverne les conditions d'accès des Installations de production, de consommation et des Systèmes CCHT aux Réseaux de transport des États membres. L'objectif est de promouvoir le bon fonctionnement et la sécurité du Système électrique de l'EEEOA.
Connection Point		means the interface at which a Facility is connected to a Transmission System, offshore Network, Distribution System, including closed Distribution Systems, or HVDC System.	60	Point de raccordement		désigne l'interface à laquelle une Installation est raccordée à un Réseau de transport, un Réseau offshore, un Réseau de distribution, y compris les Réseaux de distribution fermés, ou un Système CCHT.
Connection Site		A site at which the Facility of the User at the User's side of the Connection Point is to be installed, including the land, spaces, roads and any surfaces.	61	Site de raccordement		Un site sur lequel l'Installation de l'utilisateur, côté utilisateur du Point de raccordement, doit être installée, lequel comprend le terrain, les espaces, les routes et toutes autres surfaces.
Contingency		means an Outage that is unplanned, that is the trip of one single or several Network elements that cannot be predicted in advance.	62	Contingence		signifie une indisponibilité non planifiée, c'est-à-dire le déclenchement d'un ou plusieurs éléments de Réseau ne pouvant pas être prédit à l'avance.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Contingency List		The list of Contingencies to be simulated in order to test the compliance with the Security of Operation and assess the N-1 security criteria. More specifically, it is the list of Elements of the Relevant Grid or Generation Units or Demand Facilities whose outage one at the time should not cause cascading effects if the countermeasures considered in the Remedial Actions are applied.	63	Liste des contingences		La liste des contingences à simuler afin de tester la conformité avec la Sécurité d'exploitation et d'évaluer le critère de sécurité N-1. Il s'agit, plus précisément, de la liste des éléments du Réseau de transport pertinent ou des Unités de production ou des Installations de consommation concernés dont l'indisponibilité à un moment donné ne devrait pas provoquer des déclenchements en cascade si les contre-mesures envisagées comme Actions correctives sont appliquées.
Contribution Factor	c_i	Factor to determine the share of Primary Reserve to which an LFC Area shall contribute with respect to the total amount needed in the Synchronous Area where the LFC Area belongs to.	64	Facteur de contribution	c_i	Facteur permettant de déterminer la part de contribution de la Zone LFC à la Réserve primaire de la Zone synchrone à laquelle elle appartient.
Control Area		Is synonymous of LFC Area	65	Zone de réglage		Est synonyme de Zone LFC
Control Area Program		means the matched set of all exchange program related to a Control Area and the program for the compensation of Unintentional Deviations. As defined in the OC 7.4.2 of the Operation Code	66	Programme de Zone de réglage		désigne l'ensemble apparié de tous les programmes d'échange liés à une Zone de réglage et le Programme de compensation des Ecart Involontaires. Tel que défini dans le point OC 7.4.2 du Code d'exploitation.
Control Centre		means the set of centralised facilities intended for the control and operation of a Grid by the Grid Operator.	67	Centre de contrôle		désigne l'ensemble centralisé d'Installations destinées au contrôle et à l'exploitation d'un Réseau de transport par un Gestionnaire de réseau.
Corrective Maintenance		means unplanned maintenance interventions needed to correct or improve the behaviour of a piece of equipment, including interventions to repair after faults.	68	Maintenance corrective		Désigne les interventions de maintenance non planifiées nécessaires pour corriger ou optimiser le comportement d'un équipement, comme les interventions de réparation face à des pannes.
Credit Limit		as defined in MC14.2 and set out by the Clearing House	69	Limite de crédit		tel que défini dans le MC14.2 et établi par la Chambre de compensation

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Credit Support		it is a guarantee provided in a form of a Security Deposit to trade in the Day-Ahead Market.	70	Soutien au crédit		désigne une garantie fournie sous la forme d'un dépôt de garantie pour effectuer des transactions sur le Marché du jour pour le lendemain.
Cross-Border Interconnection		The lines that connect two (2) Transmission Systems or the Power Systems of two (2) different Member States, including metering equipment placed on the WAPPITS nodes located in each of the Member States.	71	Interconnexion transfrontalière		Les lignes qui relient deux (2) Réseaux de transport ou les Systèmes électriques de deux (2) différents États membres, incluant les équipements de comptage placés sur les nœuds du RTIE situés dans chacun des États membres.
Cross-Border Transaction		Means a transaction where the Seller must sell electricity supplied or generated from facilities operating within a Member State to a Buyer that purchases the electricity and is located in a different Member State from the Member State where that Seller is located	72	Transaction transfrontalière		Désigne une transaction dans laquelle le Vendeur doit vendre de l'électricité fournie ou produite à partir d'installations opérant dans un État membre, à un Acheteur qui achète l'électricité, et est situé dans un État membre différent de l'État membre de celui du Vendeur.
Current Transformer	CT	means an Instrument Transformer in which the secondary current, in normal conditions of use, is substantially proportional to the primary current and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections ¹ .	73	Transformateur de Courant	TC	désigne un Transformateur de mesure dans lequel le courant secondaire est, dans les conditions normales d'utilisation, pratiquement proportionnel au courant primaire et déphasé par rapport à celui-ci d'un angle approximativement nul pour un sens approprié des connexions ¹ .
Curtailment		means the reduction or cancelation of PTRs attributed to a Market Participant, by the SMO, based on the request of the System Operators, in response to a transmission capacity shortage as a result of system reliability conditions	74	Réduction		désigne la réduction ou l'annulation des PTR attribués à un Participant au marché, par l'OSM, sur la base de la requête des Opérateurs de système, en réponse à une pénurie de capacité de transport due à des conditions de fiabilité du Réseau
Daily Settlement Statement		as defined in MC 17.4	75	Relevé de règlement quotidien		tel que défini dans le MC 17.4

¹ According IEC 60050 International Electrotechnical Vocabulary

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
DAM Fallback Procedure		means the Operational Procedure to be followed where there are compelling reasons not to implement the standard procedure for the DAM operations, for instance, in case of failure of the ETS platform	76	Procédures de repli du DAM		désigne la Procédure opérationnelle à suivre lorsqu'il existe des raisons impérieuses de ne pas mettre en œuvre la procédure standard pour les opérations DAM, par exemple en cas de défaillance de la plateforme ETS.
Data Exchange		means delivery and reception of data between at least two Parties.	77	Échange de données		désigne l'envoi et la réception de données entre au moins deux Parties.
Day		One calendar day	78	Jour		Un jour calendaire
Day Ahead Market	DAM	means a component of the REM structure wherein Market Participants submit Bids and Offers for the purchase and sale of electricity to be delivered on the Delivery Day. Transactions within the DAM are executed based on the accepted Bids and Offers, with prices determined through a market-Clearing process.	79	Marché du jour pour le lendemain	DAM	désigne une composante de la structure du MRE dans laquelle les Participants au marché soumettent des Offres d'achat et des Offres de vente d'électricité à livrer le Jour de livraison. Les transactions dans le DAM sont exécutées sur la base des Offres d'achat et des Offres de vente acceptées, avec des prix déterminés par un processus de Compensation du marché.
Default Levy		Means a levy raised by the SMO as defined in MC.19.2.4	80	Prélèvement pour défaut		Désigne un prélèvement fait par l'OSM tel que défini au MC.19.2.4
Defence Plan		Means those control actions dedicated to limit the consequences of major disturbances whose severity goes beyond the Normal Contingencies of the Contingency List. As described in OC 4.3 of the Operation Code.	81	Plan de défense		Désigne l'ensemble des actions de contrôle dédiées à limiter les conséquences de perturbations majeures dont la gravité dépasse les Contingences normales de la Liste des contingences. Tel que décrit dans le point OC4.3 du Code d'exploitation
Defined Metering Point	DMP	means, the physical or virtual location at which overall accuracy compliance requirements as defined in the Metering Code are to be met. The DMP shall be defined in the relevant Interconnection Agreement. Each single circuit interconnection between two (2) Grid Operators will have two (2) DMPs, one with each Grid Operator.	82	Point de mesure défini	DMP	désigne l'emplacement physique ou virtuel pour lequel les critères globaux de conformité de précision telles que définis dans le Code de comptage doivent être remplis. Le DMP doit être défini dans l'Accord d'interconnexion correspondant. Chaque ligne d'interconnexion entre deux (2) Gestionnaires de réseau disposera de deux (2) DMP, c'est-à-dire un pour chaque Gestionnaire de réseau.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Delivery Day		Means the 24-hour period beginning at 00:00:00 (in UTC+1 time zone) during which contracted electricity is to be injected into and extracted from the WAPPITS.	83	Jour de livraison		Désigne la période de 24 heures commençant à 00:00:00 (fuseau horaire UTC+1) pendant laquelle l'électricité sous contrat doit être injectée et extraite du RTIE.
Delivery Point		means a node of the WAPPITS that is a reference for transactions in the Regional Electricity Market. The Delivery Point is set for each Cross-Border Interconnection.	84	Point de livraison		désigne un nœud du RTIE qui constitue une référence pour les transactions sur le Marché régional de l'électricité. Le Point de livraison est fixé pour chaque ligne d'Interconnexion transfrontalière.
Demand		means the amount of power required to be delivered to a Facility or part of a Facility, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.	85	Demande		désigne la puissance requise à tout ou partie d'une installation, généralement exprimée en kilowatts ou mégawatts, à un instant donné ou en moyenne sur tout intervalle de temps désigné.
Demand Facility or Load Facility		means a Facility which consumes electrical energy and is connected to one or more Connection Points to the Transmission System. A Distribution System and/or auxiliary supplies of a Generation Facility do not constitute a Demand Facility.	86	Installation de consommation		désigne une Installation qui consomme de l'énergie électrique et qui est connectée à un ou plusieurs points de raccordement au Réseau de transport. Un Réseau de distribution et/ou des fournitures auxiliaires d'une Installation de production ne constituent pas une Installation de consommation.
Demand Facility Owner		means the Entity licensed and authorized to operate a Demand Facility and responsible for complying with the REM Codes requirements applicable to the Demand Facility.	87	Propriétaire d'installation de consommation		désigne l'Entité agréée et autorisée à exploiter une Installation de consommation et responsable de la conformité avec les exigences des Codes du MRE applicables à l'Installation de consommation.
Demand Forecast		means the activity for the evaluation of the expected values of Demand at LFC Area level and for a certain future time horizon, associated to a given probability. It shall include values in energy and power.	88	Prévision de la demande		désigne l'activité pour l'évaluation des valeurs attendues de la Demande au niveau de la Zone LFC, et pour un certain horizon temporel futur, associées à une probabilité donnée. Elle doit inclure des valeurs en énergie et en puissance.
Development Plan		means the expansion plan for the Grid and Generation at national level of a Member State.	89	Plan de développement		désigne le plan d'extension du Réseau de transport et de la Production au niveau national d'un État membre.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Development Planning		means the planning activity in which the modification of the assets is required to adapt a Power System to future energy needs. The word Plan shall be intended as the results of the Development Planning endeavour.	90	Planification du développement		désigne l'activité de planification dans laquelle la modification des actifs est requise pour adapter un Système électrique aux besoins énergétiques futurs. Le mot Plan doit s'entendre, les résultats de l'effort de Planification du développement.
Direct Current	DC	means electric current that is time-independent or, by extension, periodic current the direct component of which is of primary importance.	91	Courant Continu		signifie le courant électrique indépendant du temps ou, par extension, le courant périodique dont la composante continue est d'importance primordiale.
Dispute		means any controversy, disagreement or claim arising out of or in connection with the REM Codes and/or in the operation of the Regional Electricity Market.	92	Différend		désigne toute controverse, désaccord ou plainte découlant de ou en relation avec les Codes du MRE et/ou en relation avec la gestion du Marché régional de l'électricité.
Distributed Generation or Distributed Generator		means the electric power Generation from any Generation Unit, either synchronous or Inverter-based, that is indirectly connected to the Transmission System through a Distribution System or located on the customer side of the Distribution System.	93	Production décentralisée		désigne la Production d'énergie électrique à l'aide de toute Unité de production, aussi bien synchrone qu'à onduleur, indirectement reliée au Réseau de Transport via un Réseau de distribution ou situé côté client du Réseau de distribution.
Distribution System		As defined in National Grid Code, means all high, medium and low voltage lines, and related equipment owned, maintained and operated by an Entity, which are directly connected to the Transmission System through sub-stations and used for the distribution of electricity with a view to its delivery to end-consumers.	94	Réseau de distribution		désigne toutes les lignes à haute, moyenne et basse tension et les équipements connexes tels que définis par le Code de réseau national, qui sont détenus, entretenus et exploités par une Entité, directement raccordés au Réseau de transport par l'intermédiaire de postes de transformation et utilisés pour la distribution d'électricité aux fins de sa livraison aux consommateurs finaux.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Distribution System Operator	DSO	means: 1. In such Member States, where the electricity sector is unbundled, the term “Distribution System Operator” refers to an independent Entity designated by one or more Member States that operate and maintain a Distribution System. 2. In such Member States, where the electricity industry is vertically integrated, the term “Distribution System Operator” refers to the specific department of the vertically integrated electrical utility in charge of operating and maintaining the Distribution System.	95	Gestionnaire de Réseau de Distribution	GRD	désigne : 1. Dans les États membres où le secteur de l’électricité est dé-intégré, le terme « Gestionnaire de Réseau de distribution » fait référence à une Entité indépendante désignée par un ou plusieurs États membres qui exploitent et entretiennent un Réseau de distribution. 2. Dans les États membres où le secteur de l’électricité est verticalement intégré, le terme « Gestionnaire de Réseau de distribution » désigne le département de la société du service public d’électricité chargé de l’exploitation et de l’entretien du Réseau de distribution.
Downward Reserve		means the difference between the minimum Load minus the sum of the technical minima of the Generation Facilities	96	Réserve à la baisse		désigne la différence entre la charge minimum moins la somme des minima techniques des Installations de production
Dynamic Security Assessment		means the evaluation of the ability of a Power System to withstand a defined set of Contingencies and to survive the transition to an acceptable steady-state condition. It can be performed by computer-based tools used to simulate on-line and off-line the dynamic behaviour of the Power System. It includes the angle, frequency and voltage stability and the analysis of synchrophasor recordings.	97	Analyse de la stabilité dynamique		désigne l’évaluation de la capacité d’un Système électrique à répondre à un ensemble défini de perturbations et à retrouver les conditions d’un régime permanent acceptable après une phase transitoire. Elle peut être réalisée par un outil informatique de simulation en ligne et hors ligne du comportement dynamique d’un Système électrique. Elle comprend la stabilité de l’angle, de la fréquence et de la tension, ainsi que l’analyse des enregistrements des synchrophaseurs.
ECOWAS		means the Economic Community of West African States	98	CEDEAO		désigne la Communauté Économique des États de l’Afrique de l’Ouest

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ECOWAS Regional Electricity Regulatory Authority	ERERA	Means the regulator of regional cross-border trade of electricity in the West Africa Power Pool. It is mandated to regulate the regional electricity market, as defined by Regulation C/REG.27/12/07 on the Composition, Organization, Functions, and Operations of ECOWAS Regional Electricity Regulatory Authority	99	Autorité de Régulation Régionale du secteur de l'Électricité de la CEDEAO	ARREC	Désigne le régulateur du commerce transfrontalier régional de l'électricité dans le Système d'échanges d'énergie électrique de l'Ouest Africain. Il est chargé de réguler le Marché régional de l'électricité, tel que défini par le Règlement C/REG.27/12/07 portant composition, organisation, attributions et fonctionnement de l'Autorité de Régulation Régionale du secteur de l'Electricité de la CEDEAO
Electricity Markets		means the market products that are allowed to be traded in the Regional Electricity Market, for example, the OTC Market, the Day-Ahead Market, etc.	100	Marchés d'électricité		désigne les produits de marché autorisés à être commercialisés dans le Marché Régional de l'électricité, par exemple le Marché OTC, le Marché du jour pour le lendemain, etc.
Electricity Supply Industry	ESI	Means those organizations that are involved in any or all of the Generation, transmission, distribution, import, export, sale, or purchase of electricity.	101	Industrie de fourniture d'électricité	ESI	désigne les organisations impliquées dans toute ou partie du processus de Production, transport, distribution, importation, exportation, vente ou achat d'électricité.
Element		means parts and/or equipment of a Power System, as represented in the Common Grid Model.	102	Ouvrage		désigne les pièces et/ou équipements d'un Système électrique, tel qu'il est représenté dans le Modèle de réseau commun.
Emergency State		it has the meaning given to it in OC 3.4.4 of the Operation Code.	103	Situation d'urgence ou Etat d'urgence		a la signification décrite dans le point 3.4.4 du Code d'exploitation.
Energy Identification Code	EIC	means a character code used in the MRE identifying the Parties in the cross-border trading system.	104	Code d'identification énergétique	EIC	désigne un code de caractère utilisé dans le MRE pour identifier les Parties dans le système commercial transfrontalier.
Energy Management System	EMS	means a system connected to a SCADA to control, monitor and optimize the performance of a Power system. It is based on computer-aided tools and used by the Grid Operators.	105	Système de gestion de l'énergie	EMS ou SGE	désigne un système connecté à un SCADA destiné à contrôler, surveiller et optimiser les performances d'un Système électrique. Il se base sur des outils assistés par ordinateur et utilisés par les Gestionnaires de réseau.
Energy Trading System	ETS	means an internet-based electronic platform used by the SMO for trading in the REM.	106	Système de négoce d'énergie	ETS	désigne une plateforme électronique sur internet utilisé par l'OSM pour les transactions dans le MRE.

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Entity		means any company, partnership, trust, joint venture, association, corporation or other private or public corporate body, any government agency and any other entity or body or class of entity or body designated by law as coming within the definition of the word “Entity”.	107	Entité		désigne toute société, partenariat, trust, coentreprise, association, société ou autre corps privé ou public, ainsi que tout organisme gouvernemental et toute autre entité ou organisme ou catégorie d'entités ou d'organismes désigné par la loi comme entrant dans la définition du mot « Entité ».
ENTSO-E		Means the European Network of Transmission System Operators for Electricity, which represents 40 electricity transmission system operators from 36 countries across Europe. It was formally established and given legal mandates by the EU’s Third Energy Package, which was adopted in July 2009. ENTSO-E is governed by an Assembly representing the 40 Transmission System Operators and by a Board consisting of 12 elected members.	108	ENTSO-E		désigne le Réseau européen des Gestionnaires de Réseau de Transport d'électricité, soit 40 Gestionnaires de Réseau de Transport d'électricité dans 36 pays à travers l'Europe. Il est formellement établi et doté de mandats légaux assignés par le Troisième paquet énergie de l'UE adopté en juillet 2009. L'ENTSO-E est dirigé par une assemblée représentant les 40 Gestionnaires de Réseau de transport et par un conseil composé de 12 membres élus.
Evaluation Tools		means computer-based products whose algorithms are agreed and qualified to perform simulations and computations in order to evaluate all the processes needed for the operation of the REM.	109	Outils d'évaluation		désigne des produits informatiques dont les algorithmes sont agréés et qualifiés pour effectuer des simulations et des calculs aux fins d'évaluer tous les processus requis dans la gestion du MRE.
Exceptional Contingency		It has the meaning given to it in OC 3.3.4 of the Operation Code.	110	Contingence exceptionnelle		a la signification qui lui a été attribuée dans le OC 3.3.4 du Code d'exploitation.
Expected Energy Not Served	EENS	means, in a given zone and during a given time period, the energy which is expected not to be supplied due to insufficient resources to meet Demand needs.	111	Energie non-distribuée envisagée	ENDE	désigne dans une zone donnée et pendant une période de temps donnée, l'énergie dont on s'attend à ce qu'elle ne soit pas fournie en raison de ressources insuffisantes pour répondre aux besoins de la Demande.
Expert Group		means the group under coordination of the WG4, tasked to perform centralized studies at the level of the WAPPITS	112	Groupe d'experts		désigne le groupe sous la coordination du GT4, chargé de réaliser des études centralisées au niveau du RTIE.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Explicit Auction		Auctioning process where the transmission capacity on a Cross-Border Interconnection is auctioned to the market separately and independently from the marketplaces where electrical energy price is determined.	113	Enchère explicite		Processus de mise aux enchères dans lequel la capacité de transport sur une Interconnexion transfrontalière est mise aux enchères sur le marché séparément et indépendamment des places de marché où le prix de l'énergie électrique est déterminé.
Explicit Auction Allocation Procedure		means an Operational procedure to be followed in an Explicit Auction designed and conducted by the SMO.	114	Procédure d'allocation par Enchères explicites		désigne une Procédure opérationnelle à suivre dans le cadre d'une Enchère explicite conçue et conduite par l'OSM.
Facility		means a Generation Facility, a Demand Facility, a line, an HVDC System, or any other set of Elements of the WAPP Power System	115	Installation		désigne une Installation de production, une Installation de consommation, un Système CCHT ou tout autre ensemble d'ouvrages du Système électrique de l'EEEOA.
Facility Owner		means the Entity licensed and authorized to operate a Facility and responsible for complying with the REM Codes requirements applicable to the Facility.	116	Propriétaire d'installation		désigne l'Entité agréée et autorisée à exploiter une Installation et responsable de la conformité avec les exigences des Codes du MRE applicables à l'Installation.
Fallback Auction		means an Explicit Auction resulting from applying the fallback procedures in MC 6.5.3.	117	Enchère de repli		désigne une Enchère explicite résultant de l'application des procédures de repli prévues dans le MC 6.5.3.
Fallback Day-Ahead Trading		means a day-ahead trading resulting from applying the fallback procedures in MC 13.4.3.	118	Transaction de repli du jour pour le lendemain		désigne une transaction pour le prochain jour ouvré résultant de l'application des procédures de repli prévues dans le MC 13.4.3.
Fast Fault Current		means a current injected by an Inverter-Based Generation Unit or HVDC System during and after a voltage deviation with the aim of identifying a fault.	119	Courant de détection de défauts		désigne une impulsion de courant injecté par une Unité de production à onduleur ou un Système CCHT pendant et après une variation de tension dans le but d'identifier un défaut.
Fault-Ride-Through		means the capability of electrical devices to remain connected to the Network and operate during predetermined external fault conditions	120	Tenue aux défauts		désigne la capacité des appareils électriques à rester connectés au Réseau et à fonctionner dans des conditions de défaillance externe prédéterminées
Final Gate Closure Time	FGCT	means the ultimate deadline established by the SMO for correcting the Nominations.	121	Heure de fermeture finale du guichet	HFFG	désigne l'heure limite ultime fixée par l'OSM pour corriger les Nominations.

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Financial Year		Coincide with the calendar year.	122	Exercice comptable		Coincide avec l'année civile.
First-Come First-Served		means a capacity allocation principle for the OTC Market in which who arrives first get served first before who arrives later.	123	Premier venu-premier servi		désigne un principe d'attribution de capacité pour le Marché OTC dans lequel celui qui arrive en premier est servi avant celui qui arrive plus tard
Flexibility		means the ability of a Power System to reliably and cost effectively manage the variability and the uncertainty of Demand and supply across all relevant time scales. That is, the degree to which a Power System can adjust the electricity production or consumption in response to both expected or unexpected variability. The term Flexibilization means the process of increasing the Flexibility of a Power System, and it shall be construed accordingly.	124	Flexibilité		désigne la capacité d'un Système électrique à gérer de manière fiable et économique, la variabilité et l'incertitude de la Demande et de l'offre sur toutes les échelles de temps. C'est-à-dire le niveau auquel le Système électrique peut ajuster la production ou la consommation d'électricité en réponse à leur variabilité attendue ou inattendue. Le terme Flexibilisation désigne le processus d'augmentation de la flexibilité d'un Système électrique et doit être interprété en conséquence.
Flexible AC Transmission System	FACTS	means a power electronic based system and other static equipment that provide control of one or more AC Transmission System parameters to enhance controllability and increase power transfer capability.	125	Système de transport flexible à Courant Alternatif	FACTS	désigne un système basé sur l'électronique de puissance et autres équipements statiques permettant de contrôler un ou plusieurs paramètres du Réseau de transport à Courant alternatif afin d'en améliorer la capacité de contrôle et d'augmenter la capacité de transfert de puissance.
Force Majeure Event		means, in relation to an Entity, any event or circumstance, or combination of events or circumstances, beyond the control of the Entity, which was not foreseeable, could not be prevented or overcome, and which prevents the Entity from performing its obligations under the REM Codes.	126	Évènement de force majeure		désigne, en rapport avec une Entité, tout événement ou circonstance, ou série de circonstances, imprévisible irrésistible ou insurmontable, et extérieur à la volonté de l'Entité et qui l'empêche d'exécuter ses obligations en vertu des Codes du MRE.
Forced Outage		means the unavailability of a Generation Unit, Transmission System line or Distribution System line due to an unexpected breakdown.	127	Indisponibilité fortuite		désigne une indisponibilité d'une centrale électrique, d'une ligne de transport ou d'une ligne de distribution en raison d'une panne imprévue..

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Frequency Leader		means the Grid Operator in charge of the coordination for the frequency management within a Synchronous Area.	128	Pilote de la fréquence		désigne le Gestionnaire de réseau chargé de la coordination de la gestion des fréquences dans une zone synchrone.
Frequency Response Deadband		means an interval used <i>intentionally</i> to make the frequency control unresponsive.	129	Bande morte de la réponse en fréquence		désigne un intervalle utilisé <i>intentionnellement</i> pour empêcher la commande de fréquence de répondre.
Frequency Response Insensitivity		means the feature of the control system specified as the smallest absolute magnitude of change in the frequency or input signal that can be detected by the measurement and then results in a change of output power or output signal. This interval is an inherent technological feature of the control system, and, contrary to the Frequency Response Deadband, it is <i>unintentional</i> .	130	Insensibilité de la réponse en fréquence		désigne la caractéristique du système de contrôle spécifié comme la plus petite amplitude absolue de changement de la fréquence ou du signal d'entrée pouvant être détectée par la mesure et entraînant un changement de puissance de sortie ou de signal de sortie. Cet intervalle est une caractéristique technologique inhérente au système de contrôle et, contrairement à la Bande morte de la réponse en fréquence, <i>n'est pas intentionnel</i> .
Frequency Restoration Control or Secondary Control		means a centralized function to regulate the Generation based on the available Frequency Restoration Reserves (or Secondary Reserves).	131	Processus de restauration de la fréquence ou Réglage secondaire		désigne une fonction centralisée destinée à réguler la Production en fonction des Réserves de restauration de fréquence (ou Réserves secondaires) disponibles.
Frequency Restoration Reserve or Secondary Reserve		means the Reserve to restore the frequency to the nominal value in a Power System after the Primary Control has stabilized the frequency deviations.	132	Réserve de restauration de fréquence ou Réserve secondaire		désigne la Réserve destinée à restaurer la fréquence à la valeur nominale dans un Système électrique, une fois que le Réglage primaire a stabilisé la déviation de fréquence.
Frequency Sensitive Mode	FSM	means the operating mode of a Generation Unit or HVDC System in which the active power output changes in response to a change in system frequency, in such a way that it assists with the recovery to nominal frequency.	133	Mode de sensibilité à la fréquence	FSM	désigne le mode d'exploitation d'une Unité de production ou d'un Système CCHT dans lequel la puissance active de sortie change en réponse à un changement de fréquence du système, afin de faciliter le rétablissement de la fréquence nominale.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Functional Operation		means all activities related to the control of energy flows, the regulation of frequency and voltage, and any other activity of dispatching in real-time and Outage Planning Coordination Business Process. The Functional Operation activities do not involve any physical operation of the Transmission System or Power System assets.	134	Exploitation fonctionnelle		désigne toute activité de contrôle des flux d'énergie, de régulation de fréquence et de tension, et toute autre activité de conduite en temps réel et le Processus de coordination de la planification des indisponibilités. Les activités d'Exploitation fonctionnelle n'impliquent aucune intervention physique sur les actifs du Réseau de transport ou du Système électrique.
Gate Closure Time	GCT	means the deadline established by the SMO for receiving the Nominations or Orders.	135	Heure de fermeture du guichet	GCT	désigne l'heure limite fixée par l'OSM pour recevoir les nominations ou des Offres.
Gate Opening Time	GOT	means the time established by the SMO to start receiving the Nominations or Orders.	136	Heure d'ouverture du guichet	GOT	désigne l'heure fixée par l'OSM pour commencer la réception des Nominations ou des Offres.
General Conditions	GC	means the section of the Regional Electricity Market Codes of West Africa that (i) establishes the general rules to be commonly shared and agreed upon by the Member States to support the creation of a robust Regional Electricity Market, (ii) establishes the principles for approval, compliance, implementation and utilization, and ensure the efficient management of the REM Codes, (iii) sets out the over-riding principles to be used in the implementation of the REM Codes, should specific events not be covered by the relevant Code (e.g. Unforeseen Circumstances, Force Majeure), (iv) considers all those general aspects which are not covered in the individual Codes.	137	Conditions générales	GC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain qui (i) établit les règles générales communes convenues et acceptées par les Etats Membres afin d'aboutir à la création d'un Marché régional de l'électricité robuste, (ii) établit les principes pour l'approbation, la conformité, la mise en œuvre, l'utilisation, et la gestion efficace des Codes du MRE, (iii) fixe les principes fondamentaux à utiliser dans la mise en œuvre des Codes du MRE, si des situations spécifiques ne sont pas couvertes par le Code approprié (ex: circonstances imprévues, force majeure), (iv) intègre tous les aspects généraux non couverts par les Codes individuels.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Generation		Means (i) the process by which electric energy is produced and supplied to the Network by a Generation Facility or part of a Generation Facility, (ii) the rate at which electric energy is produced and supplied to the Network by a Generation Facility or part of a Generation Facility over a period of time. It is generally expressed in kilowatts or megawatts. The term “ Generation Fleet ” refers to all the Generation Facilities installed and available on the territory of a Member State; to the Generation Facility(ies) of a specific electricity producer.	138	Production		désigne (i) le processus qui permet de produire une puissance électrique qui est fournie au Réseau par une Installation ou partie de celle-ci (ii) la puissance électrique produite et fournie au Réseau par une Installation ou partie de celle-ci exprimée en kilowatts ou en mégawatts, sur un intervalle de temps défini. Le terme « Parc de Production » peut désigner : toutes les Installations de production installées et disponibles sur le territoire d'un État membre ; la ou les Installations de production d'un producteur d'électricité spécifique.
Generation Capacity		Means the maximum electric output a Generation Unit can produce under specific conditions.	139	Capacité de Production		désigne la puissance maximale qu'une Unité de production peut produire sous certaines conditions.
Generation Facility		means a Facility that converts primary energy into electrical energy and which consists of one or more Generation Units connected to a Network at one or more Connection Points or to a Demand Facility.	140	Installation de production		désigne une Installation qui convertit une énergie primaire en énergie électrique et qui comporte une ou plusieurs Unités de production reliées à un Réseau en un ou plusieurs Points de raccordement ou à une Installation de consommation.
Generation Facility Owner		means the Entity licensed and authorized to operate a Generation Facility and responsible for complying with the REM Codes requirements applicable to the Generation Facility.	141	Propriétaire d'installation de production		désigne l'Entité agréée et autorisée à exploiter une Installation de Production et responsable de la conformité avec les exigences des Codes du MRE applicables à l'Installation de production.
Generation Shift Key	GSK	means the merit order list provided by each Grid Operator and assigned to each Generation Unit in its Power System to increase and decrease the power import into/export from the Power System.	142	Clé de répartition de la variation de la production	GSK	désigne la liste d'ordre de mérite fournie par chaque Gestionnaire de réseau et attribuée à chaque Unité de production dans son Système électrique afin d'augmenter ou de diminuer l'importation/exportation d'électricité du Système électrique.
Generation Unit		means an equipment that converts primary energy resources into electrical energy.	143	Unité de production		désigne un équipement qui converti les ressources d'énergie primaire en énergie électrique.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Glossary and Definitions	GD	means the section of the Regional Electricity Market Codes of West Africa covering the glossary, acronyms, and all the definitions used in the REM Codes.	144	Glossaire et définitions	GD	désigne la section des Codes du Marché régional de l'électricité Ouest Africain comprenant le glossaire, les acronymes et toutes les définitions utilisées dans les Codes du MRE.
Good Utility Practice		means any of the practices, methods and acts engaged in or approved by a significant portion of the international electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted internationally.	145	Bonnes pratiques de l'Industrie		désigne toutes les pratiques, méthodes et actes mis en œuvre ou approuvés par une partie importante du secteur international des services d'électricité publics au cours de la période considérée, ou toutes les pratiques, méthodes et actes qui, dans l'exercice d'un jugement raisonnable à la lumière des faits connus au moment où la décision est prise, auraient pu permettre d'atteindre le résultat souhaité à un coût raisonnable et compatible avec les bonnes pratiques commerciales, la fiabilité, la sécurité et la rapidité. Ces bonnes pratiques d'utilisation ne sont pas destinées à se limiter aux pratiques, méthodes ou actes optimaux à l'exclusion de tous les autres, mais plutôt à désigner l'ensemble de pratiques, méthodes ou actes acceptables et généralement acceptés au niveau international.
Governing Institutions		means the public authorities mandated to govern the electricity sector in the Member States, at both National and Regional level including Regional Institutions.	146	Institutions de gouvernance		désigne les autorités publiques mandatées à gérer le secteur de l'électricité dans les Etats membres, tant au niveau national que régional y compris les Institutions régionales.
Grandfathered Contracts or Grandfathered Agreements		means medium- and long-term contracts executed before the date given by the Resolution on the effective date of the ECOWAS Regional Electricity Market (29th June 2018), with the already reserved transmission capacity in the medium- and long-term by the ruling Regional Institutions.	147	Contrats protégés ou contrats avec droits acquis		désigne des contrats à moyen et long terme exécutés avant la date fixée par la résolution sur la date d'entrée en vigueur du Marché régional de l'électricité de la CEDEAO (29 juin 2018), avec la capacité de transmission déjà réservée à moyen et long terme par les institutions régionales compétentes.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Grid Model		means a computational set of data representing the physical Elements and nodes of a Power System used for performing power system simulations and analyses.	148	Modèle de réseau		désigne un ensemble de données numériques représentant les éléments et nœuds physiques du Système électrique utilisé aux fins d'effectuer des simulations et analyses du système.
Grid Operator		means either the TSO or the SO, the latter interacting with the TO on the basis of the mutual competences and duties, depending on the electricity industry structure and regulation of each Member State.	149	Gestionnaire de réseau		désigne soit le GRT soit l'OS, ce dernier interagissant avec l'OT sur la base des compétences et des devoirs mutuels, en fonction de la structure de l'industrie électrique et de la réglementation de chaque État membre.
Grid Operator External Schedule		means a schedule for the exchange of electricity between Grid Operators of different Scheduling Areas.	150	Programme Externe de Gestionnaire de réseau		désigne un programme d'échange d'énergie électrique entre des Gestionnaires de réseau de différentes Zones de programmation.
Grid Operator Temporary Non-compliance		means within the Transitional Provisions Framework, a temporary relief from compliance with the rules of the REM Codes granted to a Grid Operator but subject to a regulated process of solution.	151	Non-conformité temporaire d'un Gestionnaire de réseau		désigne dans le Cadre des dispositions transitoires une dispense temporaire du respect des règles des Codes du MRE accordée à un Gestionnaire de réseau mais soumis à un processus de solutionnement/correction régulé.
Grid or Transmission System		means all HV lines and related equipment for the transmission of electricity, which facilitate delivery to eligible customers or to distributors, in the context of cross-border electricity exchanges. When the term is used to identify the Transmission System of a Control Area or a national Power System, the term shall refer to the HV Network with respect to which a relevant Grid Operator has authority to direct operations.	152	Réseau de transport		désigne toutes les lignes à haute tension et les équipements associés pour le transport d'électricité, qui facilitent la fourniture d'électricité aux clients éligibles ou aux distributeurs, dans le cadre d'échanges d'électricité transfrontaliers. Lorsque le terme est utilisé pour identifier le Réseau de transport d'une Zone de réglage ou d'un Système électrique national, le terme renvoie au Réseau à haute tension pour lequel le Gestionnaire de réseau concerné est en charge de l'exploitation.
Grid User		means an Entity supplying to, or being supplied by, a Grid.	153	Utilisateur du réseau		désigne une Entité qui fournit de l'énergie au Réseau ou qui est alimenté en énergie par le Réseau.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Hourly Order		As defined in MC 13.1.2.1 a)	154	Offre horaire		tel que défini dans le MC 13.1.2.1 a)
HVDC Converter Station		means part of an HVDC System which consists of one or more HVDC Converter Units installed in a single location together with buildings, reactors, filters, reactive power devices, control, monitoring, protective, measuring and auxiliary equipment	155	Station de conversion CCHT		désigne une partie d'un Système CCHT qui consiste en une ou plusieurs unités de conversion CCHT installées en un seul endroit avec des bâtiments, des réactances, des filtres, des dispositifs de puissance réactive, contrôle, surveillance, protection, mesure et auxiliaires
HVDC Converter Station Owner		means the Entity licensed and authorized to operate an HVDC Converter Station and responsible for complying with the REM Codes requirements applicable to the HVDC Converter Station.	156	Propriétaire de station de conversion CCHT		désigne l'Entité agréée et autorisée à exploiter une station de conversion CCHT et responsable de la conformité avec les exigences des Codes du MRE applicables à la station de conversion CCHT.
HVDC Converter Unit		means a unit comprising one or more converter bridges, together with one or more converter transformers, reactors, converter unit control equipment, essential protective and switching devices and auxiliaries, if any, used for the conversion.	157	Unité de conversion CCHT		désigne une unité comprenant un ou plusieurs ponts de conversion, ainsi qu'un ou plusieurs transformateurs de conversion, réacteurs, équipement de contrôle d'unité de conversion, dispositifs de protection et de manœuvres essentiels et auxiliaires, utilisés, le cas échéant, pour la conversion.
HVDC Interface Point		means a point at which HVDC System equipment is connected to an AC Transmission System, at which technical specifications affecting the performance of the equipment can be prescribed.	158	Point d'interface CCHT		désigne un point auquel l'équipement du Système CCHT est relié à un Réseau de transport à Courant alternatif, auquel les spécifications techniques affectant les performances de l'équipement peuvent être prescrites.
HVDC System		means an electrical Power System which transfers energy in the form of high-voltage direct current (DC) between two or more alternating current (AC) buses and comprises at least two HVDC Converter Stations with DC transmission lines or cables between the HVDC Converter Stations.	159	Système CCHT		désigne un Système électrique qui transfère l'énergie sous forme de Courant Continu (CC) haute tension entre deux ou plusieurs jeux de barres de Courant Alternatif (CA), et comprend au moins deux stations de conversion CCHT avec lignes ou câbles de transport CC entre ces stations de conversion CCHT.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
HVDC System Maximum Current		means the highest phase current, associated with an operating point inside the U-Q/Pmax-profile of the HVDC Converter Station at maximum continuous active power which an HVDC system can exchange with the Transmission System at each Connection Point as agreed between the relevant national Grid Operator and the HVDC System Owner.	160	Courant maximal du système CCHT		désigne le courant de phase le plus élevé, associé à un point d'exploitation à l'intérieur du profil U-Q/Pmax de la Station de conversion CCHT à la puissance active continue maximale à laquelle un Système CCHT peut échanger avec le Réseau de transport à chaque Point de raccordement comme convenu entre le Gestionnaire de réseau national concerné et le Propriétaire du système CCHT.
HVDC System Owner		means the Entity licensed and authorized to operate an HVDC System and responsible for complying with the REM Codes requirements applicable to the HVDC System.	161	Propriétaire du système CCHT		désigne l'Entité agréée et autorisée à exploiter un Système CCHT et responsable de la conformité avec les exigences des Codes du MRE applicables au Système CCHT.
Imbalance		means, for each energy exchange that has taken place in a given time interval between different LFC Areas, the difference between the actual measured energy exchange, and the scheduled energy exchange.	162	Déséquilibre		désigne, pour chaque échange d'énergie ayant lieu dans un intervalle de temps donné entre différentes zones LFC, l'écart entre les valeurs respectivement d'échange d'énergie réel mesuré et planifié et tous les écarts intentionnels par rapport à cette programmation.
Implicit Allocation		means the allocation of transmission capacity included (implicitly) in the Offers and/or Bids orders placed in the DAM.	163	Allocation implicite		désigne l'allocation de la capacité de transport incluse (implicitement) dans les Offres d'achat et/ou Offres de vente placées dans le DAM.
Individual Database		means a repository of Individual Information functional to the planning process.	164	Base de données individuelle		désigne un référentiel d'informations individuelles qui sert au processus de planification.
Individual Grid Model		means a computational set of data representing the physical Elements and nodes of a Power System belonging to a Grid Operator of a single LFC Area and used for performing power system simulations and analyses	165	Modèle de réseau individuel		désigne un ensemble de données numériques, représentant les éléments et nœuds physiques appartenant à un Gestionnaire de réseau d'une seule Zone LFC du Système électrique, utilisé aux fins d'effectuer des simulations et analyses du système.
Individual Information		means data set belonging to one Grid Operator.	166	Informations individuelles		désigne une base de données appartenant à un Gestionnaire de réseau.

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Information		means any data related, but not limited, to technical, financial, commercial and Operational activities in whatever form (whether written, electronically or by any other means) associated to one specific operational Grid Operator business.	167	Informations		désigne, de façon non-exhaustive, toutes les données techniques, financières, commerciales et opérationnelles, sous quelque forme que ce soit (écrite, électronique ou par tout autre moyen) liées à une activité d'exploitation spécifique du Gestionnaire de réseau.
Information Communication Technology	ICT	means all the technology used to handle telecommunications, broadcast media, intelligent management systems, audiovisual processing and communication transmission systems, and network-based control and monitoring functions.	168	Technologie de l'Information et de la Communication	TIC	désigne l'ensemble des technologies utilisées pour gérer les télécommunications, les médias audiovisuels, les systèmes de gestion intelligents, les systèmes de traitement audiovisuel et de transmission des communications, ainsi que les fonctions de contrôle et de surveillance basées sur le réseau informatique.
Injection Point		means, in the context of the OTC Bilateral Contracts, the point in the Transmission System where the Seller is injecting its electricity Generation into the national Grid.	169	Point d'injection		désigne, dans le contexte des Contrats Bilatéraux de gré à gré, le point du Réseau de transport où le Vendeur injecte sa Production d'électricité dans le Réseau de transport national.
Insider		as defined in MC 21.2.5	170	Initié		tel que défini dans le MC 21.2.5
Insider Trading		as defined in MC 21.2.6	171	Délit d'initié		tel que défini dans le MC 21.2.6
Instrument Transformer		means an electrical transformer, with its primary winding connected with the conductor carrying the current or voltage to be measured, which gives an accurate low-current or voltage indication in its secondary winding of the high current or voltage in its primary winding. The low-current or voltage output is used for relaying, metering and indication.	172	Transformateur de mesure		désigne un transformateur électrique, dont l'enroulement primaire est relié au conducteur transportant le courant ou la tension à mesurer, qui donne une indication précise du courant fort ou de la tension forte dans son enroulement primaire, par le courant ou de la tension faible dans son enroulement secondaire,. La sortie à faible courant est utilisée pour le relais, la mesure et l'indication ;
Interchange Point		means an established physical location where power flows from one Control Area to another Control Area.	173	Point d'échange		désigne un emplacement physique établi où l'énergie transite d'une Zone de réglage à une autre.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Interconnected Member State		means a Member State which Grid is connected directly or indirectly, with another Member State.	174	État membre interconnecté		désigne un État membre dont le Réseau est relié directement ou indirectement à un autre État membre.
Interconnection Agreement		means a detailed document for each Cross-Border Interconnection between two or more Parties, specifying agreements on the management of the Cross-Border Interconnection.	175	Accord d'interconnexion		désigne un document détaillé pour chaque Interconnexion transfrontalière, entre deux ou plusieurs Parties, précisant les accords sur la gestion de l'Interconnexion transfrontalière.
Inter-Grid Operators Agreement		Is the binding agreement among Grid Operators that fixes their status of compliance and make them reciprocally liable in implementing the REM Codes. As defined in the General Conditions.	176	Accord inter-Gestionnaire de réseau		Désigne l'accord contraignant entre les Gestionnaires de réseau qui fixe leur statut de conformité et les rend réciproquement responsables dans la mise en œuvre des Codes du MRE. Tel que défini dans les Conditions Générales.
Intermediate Planning		means the phase of the Development Planning process in a time frame that covers 10-15 years ahead, and performed with 6-years rolling frequency, which is meant to periodically check and provide the information for aligning the Priority Plan to the LTTs. The Intermediate Plan is the output of the Intermediate Planning process.	177	Planification Intermédiaire		désigne la phase du processus de Planification du développement sur une période couvrant 10 à 15 ans à l'avance, et réalisée avec une révision périodique de 6 ans, qui vise à vérifier périodiquement et à fournir les informations pour aligner le Plan de Priorité sur les LTT. Le Plan Intermédiaire est le résultat du processus de Planification Intermédiaire.
Interruptible Load		means the Load of particular Demand Facilities which can be reliably reduced by a fixed capacity upon request by the Grid Operator, according to a specific agreement.	178	Charge interruptible		désigne la charge des Installations de consommation particulières qui peut être réduite d'une valeur fixe de manière fiable sur requête du Gestionnaire de réseau, conformément à un accord spécifique.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Inverter-based Generation Unit		means a unit or a set of units which can generate electrical energy, which is either non-synchronously connected to the Network or connected through power electronics, and that also has a single Connection Point to a Transmission System, Distribution System including closed Distribution System or HVDC System as well as RES-based Power Park Modules (such as Solar or wind Units) and battery energy storage systems.	179	Unité de production à onduleur		désigne une unité ou un ensemble d'unités en mesure de générer de l'énergie électrique, laquelle est soit reliée de manière non synchrone au Réseau ou par le Système électronique de puissance, et qui a également un seul Point de raccordement à un Réseau de transport, un Réseau de distribution tel qu'un Réseau de distribution fermé ou Système CCHT, ainsi que les Unités de production à EnR (telles que les unités photovoltaïques ou éoliennes) et les systèmes de stockage d'énergie par batterie.
Island		means the whole or part of a Grid that is disconnected from the interconnected WAPP Power System, having at least one Generation Unit or HVDC System supplying power to this isolated Network and controlling the frequency and voltage.	180	Réseau îloté		désigne l'ensemble ou partie d'un Réseau de transport déconnecté du Système électrique de l'EEEOA interconnecté, ayant au moins une Unité de production ou un Système CCHT alimentant ce Réseau isolé, et qui en contrôle la fréquence et la tension.
Isolated Microgrid		means a small network of electricity users with a local source of supply not intended to be connected to a wider electrical Power System, thus working as a stand-alone system.	181	Micro-réseau isolé		désigne un petit réseau d'utilisateurs d'électricité disposant d'une source locale de production et qui n'a pas vocation à se connecter à un Système électrique plus large et qui par conséquent fonctionne en système autonome.
Key Performance Indicator	KPI	means an index conventionally assumed to measure a given performance.	182	Indicateur clé de performance	KPI	désigne un indice défini par convention permettant de mesurer une performance donnée.
K-Factor		means a value, usually given in megawatts per Hertz (MW/Hz), which is normally determined for a single Control Area; it defines the frequency bias of that Control Area for Secondary Control (i.e. ' $K \cdot \Delta f$ ' in ACE); it is not to be confused with the Network Power Frequency Characteristic.	183	Facteur-K		désigne une valeur, généralement donnée en mégawatts par Hertz (MW/Hz), qui est normalement déterminée pour une unique Zone de réglage ; il définit l'écart de fréquence de cette Zone de réglage pour le Réglage secondaire (c'est-à-dire « $K \cdot \Delta f$ » dans ACE) ; il ne doit pas être confondu avec l'Energie réglante du Réseau.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Limited Frequency Sensitive Mode – Overfrequency	LFSM-O	means a Generation Unit or HVDC System operating mode which will result in active power output reduction in response to a change in system frequency above a certain value.	184	Mode de réglage restreint de la fréquence - Surfréquence	LFSM-O	désigne le mode de fonctionnement d'une Unité de production d'électricité ou d'un Système CCHT dans lequel la production de puissance active est réduite en réponse à une variation de la fréquence du réseau dès que cette dernière est supérieure à une certaine valeur.
Limited Frequency Sensitive Mode – Underfrequency	LFSM-U	means a Generation Unit or HVDC System operating mode which will result in active power output increase in response to a change in system frequency below a certain value.	185	Mode de réglage restreint de la fréquence - Sous-fréquence	LFSM-U	désigne le mode de fonctionnement d'une Unité de production d'électricité ou d'un Système CCHT dans lequel la production de puissance active est augmentée en réponse à une variation de la fréquence du réseau dès que cette dernière est inférieur à une certaine valeur.
Load		is synonymous to Demand.	186	Charge		est synonyme de Demande.
Load Shedding		means the action to interrupt the electricity supply to Demand Facilities, and it includes the UfLS, UVLD and manual Load Shedding.	187	Délestage		désigne l'action d'interrompre la fourniture en électricité d'Installations de consommation ; cela comprend l'UfLS, l'UVLD et le délestage manuel.
Load-Frequency Control	LFC	means the service of Secondary Control adopted in interconnected Power Systems to restore the system frequency to the nominal value and the cross-border electricity exchanges to the Scheduled Energy Exchanges.	188	Réglage fréquence-puissance	LFC	désigne le réglage secondaire adopté dans les Systèmes électriques interconnectés pour rétablir la fréquence de réseau à la valeur nominale et les échanges transfrontaliers d'électricité sur les lignes d'interconnexion aux valeurs des Echanges d'énergie programmés.
Load-Frequency Control Area	LFC Area	means a coherent part of the Synchronous Area of the WAPP Power System physically demarcated by points for measurement of the interchanged power and energy to the remaining interconnected Network, operated by a single Grid Operator fulfilling the obligations of LFC, and including connected physical Demand Facility and/or Generation Facility if any.	189	Zone de réglage fréquence-puissance	Zone LFC	désigne une partie cohérente du Système électrique de l'EEEOA délimitée physiquement par des points de mesure de la puissance et de l'énergie échangées vers le réseau interconnecté restant, exploité par un seul Gestionnaire de réseau remplissant les obligations LFC, et comprend, le cas échéant, une Installation de consommation et/ou une Installation de production physique connectée.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Load-Frequency Control Area Operator	LFC Area Operator	means the Entity designated by one or more Member States responsible for: 1. The coordination of exchange programs between its related Scheduling Areas and the exchanges between its neighbouring LFC Areas. 2. The LFC for its own LFC Area. 3. The coordination of the correction of time deviations. When the LFC Area is coincident with the national territory of a country, the LFC Area Operator is the designated Grid Operator.	190	Opérateur de zone de réglage de la fréquence-puissance	Opérateur de zone LFC	désigne l'Entité désignée par un ou plusieurs États membres chargée de : 1. La coordination des programmes d'échanges entre ses Zones de programmation associées et des échanges entre ses zones LFC associées. 2. La LFC pour sa propre Zone LFC. 3. La coordination de la correction des écarts temporels. Lorsque la Zone LFC coïncide avec le territoire national d'un pays, l'Opérateur de la zone LFC est le Gestionnaire de réseau désigné.
Load-rejection		means the sequence of automatic manoeuvring actions of a Generation Unit that have the purpose of reducing and adjusting the power produced by the Unit to that of its auxiliary services and thus allowing the rapid re-synchronization of the Unit. The condition is activated by the opening of the switch of a Unit due to faults occurring on the external Transmission System that cause sudden loss of the Load in the Power System and the Generation Unit to experience over-frequency.	191	Rejet de charge / îlotage		désigne la séquence d'actions de manœuvre automatique des Unités de production qui ont pour but de réduire et ajuster la puissance produite par l'unité à celle de ses services auxiliaires en permettant une resynchronisation rapide de l'Unité. La condition est activée par l'ouverture du disjoncteur d'une Unité en raison des défauts survenus sur le Réseau de transport externe, lesquels provoquent la perte soudaine de charge dans le Système électrique et la surfréquence de l'Unité de production.
Long-Term Target	LTT	means a long-term goal that shall be pursued with the development of a Cross-Border Interconnection (e.g. universal electricity access, CO2 reduction levels, percentage of RESs, storage)	192	Cible à long terme		désigne un objectif à long terme qui doit être poursuivi avec le développement d'une Interconnexion transfrontalière (ex: accès universel à l'électricité, niveaux de réduction de CO2, pourcentage de EnR, stockage,)
Long-Term Vision	LTV	means the vision developed in the strategic document by WAPP within the framework of the Long-Term Vision Planning.	193	Vision à long terme		désigne la vision développée dans le document stratégique de l'EEEOA dans le cadre du Planification de la Vision Long Terme.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Long-Term Vision Planning		means the phase of the Development Planning process in a time frame that covers 20-30 years ahead, and performed with 3 to 6-years rolling frequency, which is meant to define the LTTs and the formulation of long-term strategies to reach the LTTs. The process is also referred to as Long Term Planning.	194	Planification de la Vision à Long Terme		désigne la phase du processus de Planification du développement sur une période couvrant 20 à 30 ans à l'avance, et réalisée avec une révision périodique de 6 ans de 3 à 6 ans, qui vise à définir les LTT et à formuler des stratégies à long terme pour atteindre les LTT. Le processus est aussi appelé Planification à long terme.
Loss of Load Expectation	LOLE	means, for a given Grid Operator's Control Area, the number of hours per year when the available resource capacity is insufficient to serve the Load.	195	Espérance de défaillance de charge	LOLE	désigne, pour une Zone de réglage d'un Gestionnaire de réseau donnée, le nombre d'heures par an où la capacité disponible est insuffisante pour satisfaire la demande.
Loss of Load Probability	LOLP	means, for a given Grid Operator's Control Area, the probability that hourly Demand exceeds the resource capacity.	196	Probabilité de perte de charge	LOLP	désigne, pour une Zone de réglage d'un Gestionnaire de réseau donnée, la probabilité que la Consommation horaire dépasse la capacité de la ressource.
Main Meter		means the principal Meter that registers pre-defined electrical parameters and can be remotely accessed and read. It is to be differentiated from the Check Meter.	197	Compteur principal		désigne le Compteur de référence qui enregistre des paramètres électriques prédéfinis et peut être consulté et lu à distance. Il doit être différent du Compteur de vérification.
Maintenance Plan		means the set of scheduled maintenance works aimed at achieving prescribed levels of reliability and preservation of the assets. The Unavailability Plan is developed from the Maintenance Plan.	198	Programme de maintenance		désigne l'ensemble des travaux de maintenance planifié visant à assurer des niveaux requis de fiabilité et de préservation des actifs. Le Plan d'indisponibilité est développé à partir du Plan de maintenance.
Margin Call		means the request sent by the Clearing House to a Market Participant to increase its Trading Margin to at least the required minimum level. As defined in MC14.6 of the Market Code.	199	Appel de marge		désigne la requête envoyée par la Chambre de compensation à un Participant au marché pour porter sa Marge de négoce à au moins un niveau minimal requis. Tel que défini dans le point MC 14.6 du Code de marché.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Market Actors		mean Entities engaged in the activities of Generation, supply, transmission, distribution, and trading of electricity, including eligible customers, the national regulatory authorities and other national and regional institutions involved in the functioning of the REM.	200	Acteurs du marché		Désignent les Entités qui exercent des activités de Production, de fourniture, de transport, de distribution et de négoce d'électricité, y compris les consommateurs éligibles, ainsi que les autorités de régulation nationales et les autres institutions nationales et régionales impliquées dans le fonctionnement MRE.
Market Code	MC	means the section of the Regional Electricity Market Codes of West Africa that establishes the REM, governs an efficient, competitive, transparent and reliable market operations, and establishes and assigns the monitoring and surveillance functions of the REM.	201	Code de marché	MC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain qui établit le MRE, régit l'exploitation d'un marché efficace, compétitif, transparent et fiable, établit et attribue les fonctions de suivi et de surveillance dans le MRE.
Market Manipulation		as defined in MC 21.2.2.	202	Manipulation du marché		tel que défini dans le MC 21.2.2.
Market Monitoring Procedure		as defined in MC 1.8.5 and MC 21.4.	203	Procédure de suivi du marché		tel que défini dans le MC 1.8.5. et le MC 21.4.
Market Monitoring Report		as defined in MC 21.4.3.	204	Rapport de suivi du marché		tel que défini dans le MC 21.4.3.
Market Participant		means an Entity of the Electricity Supply Industries of any of the Member States that is registered and authorized to trade in the REM.	205	Participant au marché		désigne une Entité de l'Industrie de fourniture d'électricité d'un des États Membres, enregistrée et autorisée pour faire du commerce dans le MRE.
Market Participant Agreement		Agreement under which the SMO and each Market Participant shall agree to, observe and perform the requirements of the REM Codes.	206	Accord de participation au marché		désigne un Accord en vertu duquel l'OSM et chaque Participant au marché acceptent d'observer et d'appliquer les règles des Codes du MRE.
Market Power		means the ability of a Buyer or Seller to significantly and sustainably alter the market price from the competitive price.	207	Pouvoir de marché		désigne la capacité d'un Acheteur ou d'un Vendeur de modifier de manière significative et durable le prix du marché par rapport au prix compétitif.
Market Surveillance Committee		as defined in MC 21.5	208	Comité de surveillance du marché		tel que défini dans le MC 21.5

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Market Surveillance Report		as defined in MC 21.5.3	209	Rapport de surveillance du marché		tel que défini dans le MC 21.5.3
Market Time Unit	MTU	means the period for which the market price is established.	210	Unité de temps du marché	UTM	Désigne la période pour laquelle le prix du marché est établi.
Master Plan		refers to the ECOWAS Master Plan for the Development of Regional Power Generation and Transmission Infrastructure in West Africa.	211	Plan directeur		fait référence au plan directeur de la CEDEAO pour le développement de l'infrastructure régionale de production et de transport d'électricité en Afrique de l'Ouest.
Max Instantaneous Frequency Deviation		means the maximum expected absolute instantaneous frequency deviation after the occurrence of an Imbalance equal to or less than the Reference Incident, beyond which emergency measures are activated.	212	Écart maximal de fréquence instantané		désigne l'écart de fréquence instantané absolu maximum admis après l'occurrence d'un Déséquilibre égal ou inférieur à l'Incident de référence, au-delà duquel des mesures d'urgence sont activées.
Max Steady State Frequency Deviation		means the maximum expected frequency deviation at which the System Frequency is to be stabilized after the occurrence of an imbalance equal to or less than the Reference Incident.	213	Écart maximal de fréquence en régime permanent		désigne l'écart de fréquence maximal attendu après l'apparition d'un déséquilibre égal ou inférieur à l'incident de référence auquel la fréquence du système est censée être stabilisée
Member State		means any State connected to the WAPPITS whose Grid Operator has signed the Inter-Grid Operators Agreement. The term non-Member State means any State other than the Member State.	214	État membre		désigne tout État connecté au RTIE et dont le Gestionnaire de réseau a signé l'Accord inter-Gestionnaire du réseau. Le terme État non-membre désigne tout État autre qu'un Etat membre.
Meter		means an electric device that measures, calculates, and records pre-defined parameters such as active energy, reactive energy or both. The term Metering and its derivatives are defined accordingly.	215	Compteur		désigne un dispositif électrique qui mesure, calcule et enregistre les paramètres prédéfinis tels que l'énergie active, l'énergie réactive ou les deux. Le terme Comptage et ses dérivés sont définis en conséquence.
Meter Information Register		means the detailed data records of Meters for the Metering Database under the responsibility of the Grid Operator and to be shared and maintained.	216	Registre des informations de Compteur		désigne les enregistrements de données détaillées des Compteurs pour la Base de données de comptage sous la responsabilité du Gestionnaire de réseau, à partager et à maintenir.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Metering Code	MTC	means the section of the Regional Electricity Market Codes of West Africa that outlines common principles, and specifies minimum technical and design requirements, as well as establishing the basic rules for accessing the Meters, remotely collect the meter readings, and data collection for the Grid Operators and other Market Actors.	217	Code de comptage	MTC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain qui définit les principes communs et précise les spécifications techniques minimales, ainsi que l'établissement des règles de base pour accéder aux Compteurs, procéder au relevé à distance des Compteurs et collecter les données pour les Gestionnaires de réseau et autres Acteurs du marché.
Metering Data		means electrical quantities measured and recorded by a Metering Equipment.	218	Données de comptage		désigne les valeurs électriques mesurées et enregistrées par un Equipement de comptage.
Metering Database		means an information system established and maintained by the Grid Operators and SMO for the purpose of storing Metering Data.	219	Base de données de comptage		désigne un système d'informations mis en place et maintenu par les Gestionnaires de réseau et l'OSM dans le but de stocker les Données de comptage.
Metering Equipment		means any apparatus used to measure electrical quantities and includes the communication system by which Metering Data are transferred by a telecommunication network through the Metering Database. It includes Meter, Current Transformer, Voltage Transformer, and ancillary devices such as a modem, connectors.	220	Équipement de comptage		désigne tout appareil utilisé pour mesurer des valeurs électriques et comprend le système de communication permettant le transfert des Données de comptage au réseau de télécommunication via la Base de données de comptage. Il comprend un Compteur, un Transformateur de Courant, un Transformateur de Tension et des dispositifs auxiliaires tels qu'un modem, des connecteurs.
Microgrid		means a group of interconnected Loads and Distributed Generators at Distribution level with defined electrical boundaries that may have Black Start Capability and can operate in Island mode and/or Network-connected mode (IEC TS 62898).	221	Micro-réseau		désigne un groupe de charges interconnectées et de Production décentralisée au niveau de la Distribution ayant des limites électriques définies pouvant avoir une Capacité de démarrage autonome et fonctionner en mode réseau séparé et/ou couplé au Réseau (CEI TS 62898).
Minimum Acceptance Ratio		means the minimum acceptance rate in any Block Order, in which the block can be matched and expressed as a percentage less than 100%.	222	Ratio minimum d'acceptation		désigne le ratio minimum d'acceptation dans tout Offre en bloc, dans lequel le bloc peut être apparié et exprimé en pourcentage inférieur à 100 %.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Minimum Network Power Frequency Characteristic		means the minimum Network Power Frequency Characteristic (in MW/Hz) of an area.	223	Energie réglante minimale de réseau		désigne la valeur minimale d'Energie réglante (en MW/Hz) de réseau dans une zone
Multilateral Data Exchange		means Data Exchange among more than two Parties.	224	Échange de données multilatéral		désigne un échange de données entre plus de deux Parties.
National Grid Code		means the technical specifications and rules for the national management of each single Power System of the Member States.	225	Code de réseau national		désigne les spécifications et règles techniques de planification et d'exploitation de chaque Système électrique des États membres.
National Regulatory Authority	NRA	The competent authority in each Member State that is responsible for the function of regulation of the electricity sector.	226	Autorité de régulation nationale	ARN	désigne l'autorité compétente dans chaque État membre qui est responsable de la fonction de régulation du secteur de l'électricité.
Net Transfer Capacity	NTC	means the maximum total exchange programme [MW] between two LFC Areas compatible with security standards applicable in both areas and considering the technical uncertainties on future conditions of the interconnected Power Systems. It is calculated as the Total Transfer Capacity minus the Transmission Reliability Margin: NTC = TTC - TRM	227	Capacité nette de transfert	NTC	désigne la valeur d'échange maximum [MW] entre deux zones LFC compatibles avec les normes de sécurité applicables dans les deux zones et compte tenu des incertitudes concernant l'état futur des Systèmes électriques interconnectés. Elle est calculée en tant que capacité totale de transfert moins la marge de fiabilité de transport : NTC = TTC - TRM
Network		means a connected plant and apparatus deployed to transmit or distribute electricity. Based on international practice and IEC-EN standards ² , the following nominal voltage levels are defined for Networks: 1. Low-Voltage (LV): ≤ 1 kV 2. Medium-Voltage (MV): ≤ 35 kV 3. High-Voltage (HV): ≤ 230 kV 4. Extra-High-Voltage (EHV): ≤ 800 kV 5. Ultra-High-Voltage (UHV): ≥ 800 kV	228	Réseau		désigne une installation et un appareil déployé afin de transporter ou de distribuer de l'électricité. Selon la pratique internationale et les normes CEI-EN ² , les niveaux de tension nominaux suivants sont définis pour les Réseaux : 1. Basse tension (BT) : ≤ 1 kV 2. Moyenne tension (MT) : ≤ 35 kV 3. Haute tension (HT) : ≤ 230 kV 4. Très haute tension (THT) : ≤ 800 kV 5. Ultra-haute tension (UHT) : ≥ 800 kV

² EN 50110-1 / EN 50160 / EN 60038 / IEC 60071-1 / EN 61936-1

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Network Power Frequency Characteristic		means an imbalance in MW needed to cause a change of frequency of 1 Hz around the nominal frequency.	229	Energie réglante de réseau		désigne la variation de puissance en MW nécessaire pour entraîner un changement de fréquence de 1Hz autour de la fréquence nominale.
Network Studies		means the analyses performed with the support of a set of simulation tools to understand the expected performance of a Power System and to determine the severity of a fault or other unexpected event.	230	Études de réseau		désigne les analyses réalisées à l'aide d'un ensemble d'outils de simulation pour comprendre les performances attendues d'un Système électrique et déterminer le niveau de gravité d'une Contingence ou d'un autre événement imprévu.
Network System for the Connection		means the set of Facilities and equipment necessary for the connection of Generation Facility and/or the HVDC System and/or the Demand Facility to the Transmission System, to be implemented in the Grid in the existing configuration to the Connection Point.	231	Système de réseau pour le raccordement		Désigne l'ensemble des Installations et équipements à mettre en œuvre au sein du Réseau, dans la configuration existante d'un Point de raccordement, pour le raccordement de l'Installation de production et/ou du Système CCHT et /ou de l'Installation de consommation au Réseau de transport
Nominal Power		also known as rated capacity, nameplate capacity, installed capacity, it means the intended maximum full-Load sustained output of a Facility such as a Generation Unit, Demand Facility or other electrical apparatus can supply or absorb, usually expressed in megawatt. In case the term is referred to Generation Units, it also expressed as Generation Capacity.	232	Puissance nominale		également connue sous le nom de capacité nominale, capacité installée, signifie la puissance maximale que peut supporter une Installation telle qu'une Unité de production, une Installation de consommation ou tout autre appareil électrique capable de fournir ou d'absorber, et généralement exprimée en mégawatt. Si le terme fait référence à des Unités de production, il est également connu sous le nom de capacité installée.
Nominate		means in relation to holders of a PTR, the action to submit a schedule for the use of their PTR to SMO, and “ Nomination ” shall have corresponding meaning.	233	Nominer		signifie, en ce qui concerne les détenteurs d'un PTR, l'action de soumettre un programme d'utilisation de leur PTR à l'OSM. « Nomination » a la signification correspondante.
Non-WAPP Grid Operator		means a Grid Operator which is not a WAPP Member.	234	Gestionnaire de réseau hors EEEOA		Désigne un Gestionnaire de réseau qui est non membre de l'EEEOA.

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Normal Contingency		It has the meaning given to it in OC 3.3.3 of the Operation Code.	235	Contingence normale		A la signification qui lui a été attribuée dans le OC 3.3.3 du Code d'exploitation.
Normal State or Normal Conditions		means the Operating Condition situation in which the Power System is within operational security limits in the N-situation and after the occurrence of any Contingency from the Contingency List, considering the effect of the available Remedial Actions.	236	État normal ou Conditions normales		désigne un état de fonctionnement du Système électrique dans les limites de sécurité d'exploitation en situation N et après occurrence de toute Contingence dans la liste des Contingences figurant dans la Liste des contingences, compte tenu de l'effet des Actions correctives disponibles.
Notice of Dispute		means the notification sent by the aggrieved Party of a Dispute, which identifies and provides details of the Dispute.	237	Avis de Différend		désigne la notification envoyée par la partie lésée d'une contestation, qui identifie et fournit des détails sur la contestation.
Offer		it is a submission of a proposal of price and quantity by a Market Participant to sell energy in the Day-Ahead Market.	238	Offre de vente		désigne une soumission de proposition de prix et de quantité par un Participant au marché pour vendre de l'énergie sur le Marché du jour pour le lendemain.
Operating Condition or System State		means the set of values of voltage, current, frequency and other parameters characterizing the quality of operation of any Facility connected to the Transmission System in the same Synchronous Area for a given time.	239	Condition d'exploitation ou État du réseau		désigne l'ensemble des valeurs de tension, de courant, de fréquence et d'autres paramètres caractérisant la qualité de l'exploitation de toute Installation reliée au Réseau de transport dans une même zone synchrone à un moment donné.
Operation Code	OC	means the section of the Regional Electricity Market Codes of West Africa that define and governs the rules for supervisory and controlling the Cross-Border Interconnections in the WAPPITS. It does not deal with the Physical Operation of the Power Systems (e.g. switching) and the administration of the assets. The term Functional Operation or simply Operation refers to the scope of the Operation Code.	240	Code d'exploitation	OC	désigne la section Codes du Marché régional de l'électricité Ouest Africain qui définit et gouverne les règles de supervision et de contrôle des interconnexions transfrontalières dans le RTIE. Il ne traite pas de l'exploitation ou opération physique des Systèmes électriques (ex: la commutation) ni de l'administration des actifs. Le terme « Exploitation fonctionnelle » ou tout simplement « Exploitation » fait référence au champ d'application du Code d'exploitation.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Operation Security Standard	OSS or N-1 OSS	means a set of security criteria that each Grid Operator shall adopt to operate its Power System in Normal State and in case of Contingencies.	241	Norme de sécurité d'exploitation	OSS ou N-1 OSS	désigne un ensemble de critères de sécurité que tout Gestionnaire de réseau doit adopter pour exploiter son Système électrique à l'état normal et en situation de Contingence.
Operational		is a derivative of Functional Operation. "Operational" is defined accordingly.	242	Opérationnel(le)		est un dérivé d'Exploitation fonctionnelle, « opérationnel (le) », est défini en conséquence.
Operational Agreement		means, for each Facility to be connected to the Grid, a contract agreed upon and signed between a Facility Owner and the relevant Grid Operator that define the respective responsibilities in the context of the operation and control of the functional portions of the Relevant Grid.	243	Accord d'exploitation		désigne, pour chaque Installation à raccorder au Réseau de transport, un contrat signé entre un propriétaire d'installation et le Gestionnaire de réseau concerné qui définit les responsabilités respectives dans le cadre de l'exploitation et du contrôle des parties fonctionnelles du réseau de transport pertinent.
Operational Data		means the set of data obtained from a Power System and comprises, but not limited to, Snapshots, reference data sets, LFC data, frequency monitoring data, frequency measurement campaign data, data on power exchanges as well as real-time measurements.	244	Donnée d'exploitation		désigne l'ensemble des données obtenues à partir d'un Système électrique et comprend notamment des données instantanées, des ensembles de données de référence, des données LFC, des données de surveillance de fréquence, des données de campagne de mesure de fréquence, des données sur les échanges d'énergie ainsi que des mesures en temps réel.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Operational Limit		means the set of maximum and minimum values of electrical parameters established with criteria that guarantee that the Power System is working as designed. The parameters include voltage, current, frequency and other parameters characterizing the quality of Operation of any Facility connected to the Transmission System. Operational Limits can be determined by the physical characteristics of an Element (loading limits) or by the conditions of the Power System, if more stringent than the previous ones. Operational Limits can be permanent and transient, and both can vary with the season.	245	Seuil d'exploitation		désigne l'ensemble des valeurs maximums et minimums des paramètres électriques établis avec des critères capables de garantir le bon fonctionnement du Système électrique. Les paramètres comprennent la tension, le courant, la fréquence et d'autres paramètres caractérisant la qualité de l'exploitation de toute Installation connectée au Réseau de transport. Les seuils d'exploitation peuvent être déterminés par les caractéristiques physiques d'un élément (limites de charge) ou par les conditions du Système électrique, si celles-ci sont plus strictes. Les seuils d'exploitation peuvent être permanents et temporaire, et peuvent varier selon la saison.
Operational Procedure		means the detailed coordinated instructions designed to perform a given Operational process, to be developed by SMO and/or WAPP and approved by ERERA.	246	Procédure opérationnelle		désigne les instructions détaillées et coordonnées conçues pour exécuter un processus Opérationnel donné, qui doivent être élaborées par l'OSM et/ou l'EEOA et approuvées par l'ARREC.
Operator Training Simulator or Dispatcher Training Simulator	OTS or DTS	means a computer-based training system that uses a dynamic simulation model for emulating the functioning and operation of the Power System.	247	Simulateur de formation des opérateurs	OTS ou DTS	désigne un système de formation informatisé qui utilise un modèle de simulation dynamique pour émuler le fonctionnement et l'exploitation du Système électrique.
Operators' Training Code	OpTC	means the section of the Regional Electricity Market Codes of West Africa that defines a standard framework for training of the Grid operator personnel operating the Power System in order to provide reasonable assurance that they have and hold up the knowledge and skills to operate the Power System in a safe and reliable manner under all conditions and at all times.	248	Code de formation des Opérateurs	OpTC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain qui définit un cadre formel pour la formation du personnel du Gestionnaire de réseau exploitant le Système électrique afin de s'assurer de façon raisonnable qu'ils aient la connaissance et les compétences nécessaires pour exploiter le Système électrique de manière sûre et fiable, dans toutes les situation et à tout moment.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Order		means an Offer or Bid entered by a Market Participant into the ETS for conducting trade in the Day-Ahead Market.	249	Offre		désigne une Offre de vente ou une Offre d'achat faite par un Participant a marché dans l'ETS pour effectuer des échanges sur le Marché du jour pour le lendemain.
OTC Fallback Procedure		means the Operational Procedure to be followed in case it is not possible to implement the standard procedure for the operations of OTC Market	250	Procédures de repli de l'OTC		désigne la Procédure opérationnelle à suivre dans le cas où il n'est pas possible de mettre en œuvre la procédure standard pour les opérations du Marché OTC.
OTC Platform		means an electronic platform to register the Market Participants in the OTC Market and to operate the OTC Market.	251	Plateforme de gré à gré ou Plateforme de Marché OTC		désigne une Plateforme électronique permettant d'enregistrer les Participants au marché sur le Marché OTC et gérer le Marché OTC.
Out of Range Contingency		it has the meaning given to it in OC 3.3.5 of the Operation Code.	252	Contingence hors dimensionnement		A la signification qui lui a été attribuée dans le OC 3.3.5 du Code d'exploitation.
Outage		means the interruption or removal of an Element from service, unavailability for connection of an Element or temporary de-rating, restriction of use, but not limited to, permitting the performance of inspections, tests or repairs on an Element, and will include a Planned Outage and a Forced Outage.	253	Indisponibilité		Désigne l'interruption ou la mise hors service d'un Ouvrage, l'indisponibilité pour le raccordement d'un Ouvrage ou le déclassement temporaire, la restriction d'utilisation ou la réduction des performances d'un Ouvrage pour quelque raison que ce soit, y compris, de façon non-exhaustive, l'autorisation à effectuer des inspections, des essais ou des réparations sur l'Ouvrage, ainsi qu'une Indisponibilité planifiée et une Indisponibilité fortuite.
Outage Planning Coordination Business Process		means a task of the Functional Operation endeavour, aimed at matching the Generation with the forecast Demand, including Reserve margins and taking account the unavailability of Generation Facilities and the Elements of the Grid across various time scales.	254	Processus de coordination de la planification des indisponibilités		désigne une tâche dans l'Exploitation fonctionnelle, visant à faire correspondre la production avec la consommation prévisionnelle, incluant les Marges de réserve et tenant compte de l'indisponibilité des moyens de production et des éléments du Réseau de transport à différentes échelles de temps.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Over the Counter Market	OTC Market	Refers to the regional market based on cross border transactions using Bilateral Contracts to trade capacity and energy or just energy in the medium and long-term.	255	Marché de gré à gré	Marché OTC	Fait référence au marché régional basé sur des transactions transfrontalières utilisant des contrats bilatéraux pour échanger de la capacité et de l'énergie ou simplement de l'énergie à moyen et long terme.
Overall Network Power Frequency Characteristic		means the Network Power Frequency Characteristic (in MW/Hz) including all contribution (Primary Control of all the Generation Fleet, self-regulation of Load).	256	Energie réglante globale de réseau		désigne l'énergie réglante (en MW/Hz) de réseau, y compris toute contribution (réglage primaire de l'ensemble du parc de production, autoréglage de la charge).
Overall Primary Control Reserve		means minimum power for Primary Control determined at Synchronous Area level subjected to agreement according to the Reference Incident.	257	Réserve globale du réglage primaire		désigne la puissance minimum de réglage primaire, déterminée au niveau de la zone synchrone et soumise à accord conformément à l'incident de référence.
Parties in Dispute		means, in a Dispute, the aggrieved Party/Parties and the defendant Party/Parties.	258	Parties au différend		désigne, dans un différend, la ou les Parties lésées et la ou les Parties défenderesses
Party / Parties		It refers to an individual or group of individuals acting as a single Entity, involved in agreements, lawsuits, transactions, contracts, or accidents.	259	Partie/Parties		désigne un individu ou un groupe d'individus agissant en tant qu'Entité unique, impliqués dans des accords, des différends, des transactions, des contrats ou des accidents.
Phasor Measurement Unit	PMU	means an intelligent electronic device designed and built in numerical technology and used to estimate the magnitude and phase angle of an electrical phasor quantity (such as voltage or current) in a Network using a common time source for synchronization.	260	Synchrophaseur	PMU	désigne un dispositif électronique intelligent conçu et intégré dans une technologie numérique et utilisé pour estimer l'amplitude et l'angle de phase d'une quantité de phaseur électrique (telle que la tension ou le courant) dans un Réseau, en utilisant une base de temps commune pour la synchronisation.
Physical Operation		means such part of the management of a Power System attaining the physical execution of Operational commands, such as switching and maintenance performance, and all the activities requiring a close contact with the assets.	261	Exploitation physique		désigne la partie de la gestion d'un Système électrique réalisant l'exécution physique des commandes Opérationnelles au contact des équipements, telles que les activités de commutation et de maintenance, et toutes les activités nécessitant un contact étroit avec les actifs.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Physical Transmission Right	PTR	means the right of import or export of electricity by a Cross-Border Interconnection, allocated to a Market Participant by any capacity allocation methodology (and both for the OTC Market and the DAM). The PTR entitles its holders (relevant Market Participants) to physically transfer a certain volume of electricity in a certain period of time between a Cross-Border Interconnection in a specific direction.	262	Droit de transport physique	PTR	désigne le droit d'importation ou d'exportation d'électricité sur une Interconnexion transfrontalière, attribué à un Participant au marché par toute méthode d'attribution de la capacité (et à la fois pour le marché de gré à gré et le DAM). Le PTR permet à ses détenteurs (participants au marché concernés) de transférer physiquement un certain volume d'électricité pendant une certaine période de temps sur une Interconnexion transfrontalière dans une direction spécifique.
Planned Outage		means an Outage that is planned and intentional.	263	Indisponibilité planifiée		désigne une indisponibilité planifiée et intentionnelle.
Planning Code	PC	means the section of the Regional Electricity Market Codes of West Africa that defines and regulates the process for the Development Planning of the Cross-Border Interconnections of the WAPP Power System	264	Code de planification	PC	désigne la section des Codes du Marché régional de l'électricité Ouest Africain définissant et régissant le processus de Planification du développement des interconnexions transfrontalières du Système électrique de l'EEEOA
Point of Common Coupling	PCC	Connection Point between the Network and the Connected Microgrid.	265	Point de couplage commun	PCC	Point de raccordement entre le Réseau et le Micro-réseau connecté.
Positions		means the cash rights and corresponding obligations which arise from the Clearing of energy transactions in the Day-Ahead Market and have not yet been settled.	266	Positions		désigne les droits en espèces et les obligations correspondantes qui découlent de la Compensation des transactions énergétiques sur le marché du jour pour le lendemain et qui n'ont pas encore été réglés.
Power Purchase Agreement	PPA	means a bilateral agreement between a Buyer and a Seller either for capacity and/or energy	267	Contrat d'achat d'électricité	PPA	désigne un Contrat bilatéral entre un Acheteur et un Vendeur pour la capacité et/ou l'énergie
Power System		means the network of all the electrical facilities deployed to generate, transmit, and distribute electricity.	268	Système électrique		désigne l'ensemble des installations électriques interconnectées déployés pour produire, transporter et distribuer de l'électricité.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Power System Stabilizer	PSS	means an additional functionality of the AVR of a Synchronous Generation Unit whose purpose is to damp power oscillations.	269	Stabilisateur de puissance	PSS	désigne une fonctionnalité supplémentaire du Régulateur automatique de tension d'une Unité de production synchrone dont le but est d'amortir les oscillations de puissance.
Preventive Scheduled Maintenance		means the planned maintenance interventions for preserving adequate reliability levels of an Element of the Power System. It includes mainly periodic maintenance according to the manufacturers' instructions and maintenance interventions prescribed by the relevant regulation that can be scheduled in advance.	270	Maintenance préventive planifiée		désigne les interventions de maintenance planifiées pour conserver des niveaux de fiabilité adéquats d'un élément du Système électrique. Elle comprend principalement la maintenance périodique selon les instructions des fabricants et les interventions de maintenance prescrites par la réglementation pertinente, lesquelles peuvent être planifiées à l'avance.
Primary Control		means centralized automatic function to regulate the Generation based on Primary Reserves.	271	Réglage primaire		désigne une fonction automatique centralisée permettant d'ajuster la production à partir des réserves primaires.
Primary Control Time		means the time in which the resources available for Primary Control are completely supplied.	272	Temps de réglage primaire		désigne le temps pendant lequel les ressources disponibles pour le réglage primaire sont fournies en totalité.
Primary Reserve or Frequency Containment Reserve		means the first Reserve available to contain the frequency deviation after an unbalance in the Power System.	273	Réserve primaire ou Réserve de stabilisation de fréquence		désigne la première réserve disponible pour limiter la déviation de fréquence après un déséquilibre dans le Système électrique.
Priority Plan		means the result of the Priority Plan Development process as ruled by the Planning Code concerning the expansion plan for Cross-Border Interconnections and Generation and Transmission, including reserve margins, in a horizon of ten (10) years, with six (6)-years rolling frequency.	274	Plan des priorités		désigne le résultat du processus de Développement du Plan de priorité tel que régi par le Code de planification concernant le plan d'expansion des interconnexions transfrontalières, de la production et du transport, incluant les marges de réserve, à un horizon de dix (10) ans, avec six (6) ans de fréquence de révision.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Priority Plan Development		means the phase of the Development Planning process in a time frame that covers 10 years ahead, and performed with 6-years rolling frequency, which delivers a definite list of priority transmission projects at ECOWAS level.	275	Développement du plan de priorités		désigne la phase du processus de Planification du développement sur une période couvrant 10 ans à l'avance, et réalisée avec une révision périodique de 6 ans, qui fournit une liste définitive de projets de transmission prioritaires au niveau de la CEDEAO.
Prudential Dashboard		refers to, as defined in the Market code MC 14.5.2, the dashboard implemented in the ETS to provide each Market Participant in the Day-Ahead Market with the latest prudential information	276	Tableau de bord prudentiel		Désigne, comme défini dans le Code du marché MC 14.5.2, le tableau de bord prudentiel mis en place sur l'ETS afin de fournir à chaque Participant au marché sur le Marché du jour pour le lendemain les dernières informations prudentielles
Prudential Margin		As defined in the Market code MC 14.4.2	277	Marge prudentielle		Comme défini dans le Code du marché MC 14.4.2
Publish		means, in respect of a document or Information, to make that document or Information available in the public domain in accordance with ERERA and SMO's transparency principles and procedures. The term “ Publication ” shall be interpreted accordingly.	278	Publier		signifie, pour un document ou une information, rendre disponible ledit document ou ladite information dans le domaine public conformément aux principes et procédures de transparence de l'ARREC et de l'OSM. Le terme « Publication » doit être interprétée en conséquence.
Reallocation		means a rule-supported financial arrangement under which two (2) Market Participants request SMO to make matching debits and credits to the position of those Market Participants in the Day-Ahead Market. The reallocation normally represents an off-market financial commitment, such as a hedge contract between the credit and debit Parties, but SMO is not a Party to that contract. The objective is to reduce the Credit Support or Guarantee requirements.	279	Réallocation		signifie un arrangement financier soutenu par des règles selon lequel deux participants au marché demandent à l'OSM d'effectuer des débits et des crédits correspondants à la position de ces participants au marché dans le marché du jour pour le lendemain. La réallocation représente normalement un engagement financier hors marché, tel qu'un contrat de couverture entre les Parties créditrice et débitrice, mais l'OSM n'est pas Partie de ce contrat. L'objectif est de réduire les exigences de Soutien au crédit ou les exigences de garantie.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Real-Time Data Exchange	RTDE	means the Data Exchange in real-time, which describes a current status of the Power System, done automatically or on request e.g. after a change of status or value.	280	Échange de données en temps réel		désigne l'échange de données en temps réel, lequel décrit un état actuel du Système électrique, effectué automatiquement ou sur demande, par exemple après un changement d'état ou de valeur.
Record of Inter System Safety Precautions		means written record of inter-system safety precautions to be compiled in accordance with the provisions of National Grid Codes.	281	Registre des précautions de sécurité entre les systèmes		désigne un registre des précautions de sécurité entre les systèmes à remplir conformément aux dispositions des Codes de réseau nationaux.
Reference Incident		As defined in Operation Code OC 3.3.3	282	Incident de référence		Comme défini dans le Code d'Exploitation OC 3.3.3
Region		means the whole geographical region of the Member States. Derivatives such as "Regional" are defined accordingly.	283	Région		désigne l'ensemble de la région géographique des États membres. Les mots dérivés, tel que « régional », sont définis en conséquence.
Regional Annual Unavailability Plan	RAUP	means the Unavailability Plan at Regional level based on all the available AUPs of the Region.	284	Programme annuel d'indisponibilité régional	RAUP	désigne le Programme d'indisponibilité au niveau régional basé sur tous les AUP disponibles de la Région.
Regional Compensation Party	RCP	means, within the framework of the Regional Transmission Tariff Methodology (RTTM) refer to in MC 24, the Entity in each Control Area that acts as intermediary of the compensations as a result of the expected use of Network elements of other Control Areas by the generators and Loads in its Control Area and vice versa.	285	Partie pour la compensation régionale	RCP	désigne, dans le cadre de la Méthodologie de tarification du transport régional (RTTM) indiqué au MC24, l'Entité de chaque Zone de réglage qui agit en tant qu'intermédiaire des compensations à la suite de l'utilisation attendue d'éléments de réseau d'autres Zones de réglage par les producteurs et les Charges dans sa Zone de réglage et vice versa.
Regional Database		means the database which contains all the information necessary for the fulfilment of the functions of the SMO and the recording of Regional Electricity Market results and developments for the information of stakeholders.	286	Base de données régionale		désigne une base de données contenant toutes les informations nécessaires à l'accomplissement des fonctions de l'OSM et à l'enregistrement des résultats et des évolutions du Marché régional d'électricité pour l'information des parties prenantes.
Regional Electricity Market	REM	means all cross-border electricity trading and related services made through the Cross-Border Interconnections within the WAPPITS .	287	Marché régional de l'électricité	MRE	Désigne tous les échanges d'électricité transfrontaliers et les services connexes effectués via les interconnexions transfrontalières au sein du RTIE .

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Regional Electricity Market Codes of West Africa or REM Codes	REMC-WA	means the whole of the documents that define the shared principles, methods, technical and commercial rules regulating the different aspects of the management of the interconnected WAPP Power System for the appropriate planning and operation of the Regional Electricity Market (REM). The Regional Electricity Market Codes of West Africa, hereinafter referred to as the REM Codes comprises of six (6) codes (i.e., Planning Code, Connection Code, Operation Code, Market Code, System Operator Training Code, Metering Code), the Glossary and Definitions, and the General Conditions, whose contents apply to all the six (6) Codes.	288	Codes du Marché régional de l'électricité Ouest Africain ou Codes du MRE	CMRE-OA	désigne l'ensemble des principes, méthodes et règles techniques communs qui régissent un aspect donné de la gestion du Système électrique de l'EEEOA interconnecté en termes de planification et l'exploitation appropriées du Marché régional de l'électricité (MRE). Les Codes du Marché régional de l'électricité Ouest Africain, ci-après dénommés les Codes du MRE comprennent six (6) codes (c'est-à-dire le Code de planification, le Code de raccordement, le Code d'exploitation, le Code du marché, et le Code de formation des opérateurs, le Code de comptage), le glossaire et définitions, ainsi que les conditions générales, dont le contenu s'applique à tous les six (6) Codes.
Regional Electricity Market Regulation	REMR	means all applicable decisions, rules and regulations related to the Regional Electricity Market (REM) and ensuring cross-border exchange and transport of electricity among Member States.	289	Règlementation du Marché régional de l'électricité	RMRE	désigne l'ensemble des décisions, règles et règlements applicables au Marché régional de l'électricité (MRE) et garantissant les échanges et le transport transfrontaliers d'électricité entre les États membres.
Regional Institutions		refers to WAPP, the SMO, ERERA, ECOWAS Court of Justice and any other relevant regional institutions involved in the functioning of the REM.	290	Institutions régionales		se réfèrent à l'EEEOA, l'OSM, l'ARREC, la Cour de Justice de la CEDEAO et toute autre institution régionale impliquée dans le fonctionnement du MRE
Regional Seasonal Outlook		it has the meaning given to it in OC 6.9 of the Operation Code.	291	Perspective saisonnière régionale		a la signification qui lui a été attribuée dans le OC 6.9 du Code d'exploitation.
Regional Transmission Tariff Methodology	RTTM	means the methodology adopted and approved by ERERA for distributing the costs among the Market Participants for using the transmission Networks of the Grid Operators and the WAPPITS during their trading in the REM.	292	Méthodologie de tarification du transport régional	RTTM	désigne la méthodologie adoptée et approuvée par l'ARREC pour répartir les coûts entre les Participants au marché pour l'utilisation des Réseaux de transport des Gestionnaires de réseau et du RTIE lors de leurs transactions dans le MRE.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Relevant Grid		means, with reference to each national Power System, it is the part of the Grid under the responsibility of its Grid Operator, whose operation affects the electricity exchange and the SoO on the Cross-Border Interconnections and influences the values of the cross-border TTC. It can potentially represent all the Elements of the Grid.	293	Réseau pertinent		Désigne, en ce qui concerne chaque Système électrique national, la partie du Réseau de transport sous la responsabilité d'un Gestionnaire de réseau dont l'exploitation affecte les échanges d'électricité et le SoO sur les Interconnexions transfrontalières et influence les valeurs de la TTC transfrontalière. Il peut potentiellement représenter tous les éléments du réseau.
Remedial Action		means any Operational action needed to avoid cascading effects after the occurrence of a Contingency on the Contingency List.	294	Action corrective		désigne toutes les actions Opérationnelles nécessaires pour éviter les effets en cascade après la survenue d'une Contingence figurant sur la Liste des contingences.
Remedy Request Notice		as defined in MC 23.7	295	Avis de demande de correction		tel que défini dans le MC 23.7.
Remote Terminal Unit	RTU	means a microprocessor-based electronic device used in control systems to connect various hardware to distributed control systems or SCADA systems	296	Unité terminale à distance	RTU	désigne un dispositif électronique à microprocesseur utilisé dans les systèmes de contrôle pour connecter divers équipements à des systèmes de contrôle distribués ou de réglage et acquisition des données.
Renewable Energy Source	RES	means the resources for production of electricity from on-going natural processes, such as solar, wind, flowing water, biological processes, and geothermal heat flows.	297	Source d'Énergie Renouvelable	EnR	désigne les ressources de production d'électricité à partir de processus naturels renouvelés continuellement tels que le soleil, le vent, l'eau, les processus biologiques et les flux de chaleur géothermique.
Replacement Reserve or Tertiary Reserve		means the Reserves to be made available to restore the adequate level of Secondary Reserve due to permanent causes of Imbalances between Demand and Generation.	298	Réserve de remplacement ou Réserve tertiaire		désigne les Réserves à mettre à disposition pour rétablir le niveau adéquat de réserve secondaire en raison de causes permanentes de Déséquilibres entre la consommation et la production.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Reserve		means all active power resources, if procured ex ante or in real-time, or according to legal obligations, which are available to the Grid Operators for balancing purposes and maintaining the frequency.	299	Réserve		désigne toutes les ressources d'énergie active, si précédemment acquises ou acquises en temps réel, ou conformément aux obligations légales, à la disposition des Gestionnaires de réseau à des fins d'équilibrage et de maintien de la fréquence.
Reserve Sharing		refers to a condition – subject to a formal agreement – that allows Grid Operators under certain circumstances (i.e. the respect of the NTC and no use of the minimum amount of Reserve allocated for individual LFC) to share part of their available Reserves between each other. Grid Operators can take the Reserve Sharing, made available to them, into account in order to meet individual Reserve requirements.	300	Partage de la réserve		fait référence à une condition, sous réserve d'un accord formel, permettant aux Gestionnaires de réseau, sous certaines conditions (c'est-à-dire le respect des NTC et l'absence d'utilisation du montant minimum de réserve alloué pour chaque LFC individuel) de partager une partie de leurs réserves disponibles entre eux. Les Gestionnaires de réseau peuvent prendre en compte le partage de la réserve, mis à leur disposition, afin de répondre aux besoins individuels de Réserve.
Restoration		means the general process of recovering the normal functioning of a Power System after a Blackout State or Emergency State.	301	Reconstitution		Processus général de restauration du fonctionnement normal d'un Système électrique après une Panne de courant généralisée ou un Etat d'urgence.
Restoration Plan		means the structured sequence of Operational actions to perform the Restoration.	302	Plan de reconstitution		désigne la séquence structurée d'actions Opérationnelles pour effectuer la Reconstitution.
Safety Precautions		means safeguard actions taken in advance to protect life and property against possible danger, failure, or injury.	303	Précautions de sécurité		désigne des mesures de sauvegarde prises à l'avance pour se protéger contre un danger, une panne ou une blessure possible, comme la mise à la terre et l'isolation.
Scenario		means an outlook of the future characterized by guiding indicators. Accordingly, each scenario is quantified by the Generation mix, the characteristics of the Demand and other parameters for the market studies. A Scenario is not a prediction to which a probability is associated.	304	Scénario		désigne une perspective d'avenir caractérisée par des indicateurs directeurs. En conséquence, chaque scénario est quantifié par le mix de Production, les caractéristiques de la Demande et d'autres paramètres pour les études de marché. Un Scénario n'est pas une prédiction à laquelle une probabilité est associée.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Scheduled Energy Exchange		means a cross-border energy exchange that has been scheduled to take place in accordance with the REM Codes;	305	Échange d'énergie programmé		désigne un échange d'énergie transfrontalier qui a été programmé conformément aux Codes du MRE
Scheduling Area		means an area within which the Grid Operators obligations regarding scheduling apply in relation to operational or organizational needs.	306	Zone de programmation		désigne une zone dans laquelle les obligations des Gestionnaires de réseau en matière de programmation s'appliquent en raison de besoins d'exploitation ou organisationnels.
Scheduling Area Exchange Document	SAX	means the document containing the data set representing the energy exchange agreed between two Grid Operators. This document is the input for the Verification Process.	307	Document d'échange entre zones de programmation	SAX	désigne le document contenant l'ensemble des données représentant l'échange d'énergie convenu entre deux Gestionnaires de réseau. Ce document est la base du Processus de vérification.
Secondary Control		means the Frequency Restoration Control	308	Réglage secondaire		désigne le processus de restauration de la fréquence
Secondary Reserve		means the Frequency Restoration Reserve	309	Réserve secondaire		désigne la réserve de restauration de fréquence
Security Assessment		means the process to evaluate the relative SoO level of a Power System in its present Operating Condition (i.e., determination of whether the Power System is in the Normal or Alert State). It shall be carried out using the best available Grid model, updated with the conditions of the hour being analysed.	310	Évaluation de sécurité		désigne le processus d'estimation du niveau de la SoO d'un Système électrique dans son état de fonctionnement actuel (c'est-à-dire déterminer si le Système électrique est en état normal ou d'alerte). Elle doit être effectuée en utilisant le meilleur modèle de réseau disponible et mis à jour avec les conditions de l'heure à analyser.
Security Deposit		means an amount of money or cash equivalent that is given as a measure of security for the recipient, as a form of guarantee on the ability of the Party to fulfil its contracted obligations.	311	Dépôt de garantie		désigne une somme d'argent qui est donnée comme une mesure de sécurité pour le bénéficiaire, comme une forme de garantie sur la capacité de la Partie à remplir ses obligations contractuelles.
Security of Operation	SoO	means the ability of a Power System to function with adequate reliability and to withstand the stresses due to faults and other external events according to predetermined Operation Security Standards.	312	Sécurité d'exploitation	SoO	désigne l'attitude d'un Système électrique à fonctionner avec une fiabilité adéquate et à résister aux contraintes dues à des pannes et à d'autres événements externes, conformément à des Normes de sécurité d'exploitation prédéterminées.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Security of Supply	SoS	means the capability of a Power System to cover the Demand in each period of time and for a given area.	313	Sécurité d'approvisionnement	SoS	désigne la capacité d'un Système électrique à couvrir la charge ou consommation pour chaque période de temps et pour une zone donnée.
Seller		A Market Participant that makes an Offer of electricity in the Regional Electricity Market.	314	Vendeur		Un Participant au marché qui fait une Offre de vente de l'électricité sur le Marché régional de l'électricité.
Settlement		means the process that reconciles differences between Seller's contractual deliveries of electricity and the Demand of its Buyers. The Settlement should be performed for every Trading Interval.	315	Règlement		désigne le processus qui concilie les différences entre les livraisons contractuelles d'électricité du Vendeur et la Demande de ses Acheteurs. Le Règlement doit être effectué pour chaque Intervalle de négoce.
Shortage		means any situations in which, for any reason, the Power System is no longer capable of supplying the Demand.	316	Déficit		désigne toutes les situations dans lesquelles, pour une raison quelconque, le Système électrique n'est plus capable de couvrir la consommation avec les caractéristiques standards de SoS.
Snapshot		means the set of data and Information at a given instant of each Power System in terms of Grid topology, nodal Generation injections, nodal voltages in magnitude and phases and nodal Loads	317	Snapshot ou Instantané		désigne l'ensemble de données et d'informations à un instant donné de chaque Système électrique en termes de topologie du Réseau de transport, d'injections de Production nodales, de tensions nodales en amplitude et en phases et de Charges nodales
Special Protection Scheme		is synonymous to WAPS.	318	Dispositifs de protection spéciaux		est synonyme de WAPS.
Spinning Reserve		means the unused capacity available from Generation Units or equivalent power resources working already synchronously with the Transmission System which can compensate power deficit or frequency drops for a given period of time. The term Spinning is defined accordingly.	319	Réserve tournante		désigne la capacité inutilisée disponible des Unités de production ou des ressources énergétiques équivalentes préalablement synchronisées avec le Réseau de transport, capables de compenser les coupures de courant ou les chutes de fréquence dans un laps de temps donné. Le terme « tournant » est défini en conséquence.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Splitting Ratio		means the rate at which the NTC is divided between the timeframes for capacity allocation.	320	Ratio de répartition		désigne le taux de répartition de la NTC entre les échéances d'attribution des capacités.
Standard Frequency Range		means a defined interval around the nominal frequency within which the system frequency of a Synchronous Area is supposed to be operated.	321	Plage de fréquence standard		désigne un intervalle défini symétriquement autour de la fréquence nominale à l'intérieur duquel la fréquence du système d'une Zone synchrone est censée fonctionner.
State Estimator		means a computer-based application for online monitoring, analysis, and control of the Power System.	322	Estimateur d'état		désigne une application informatique de surveillance, d'analyse et de contrôle en ligne du Système électrique.
Study Area Group		refers to the group under coordination of the WG4, tasked to perform market studies and other activities inherent to a particular electrical are, as defined in the Planning Code.	323	Groupe de zone d'étude		Fait référence au groupe sous la coordination du GT4, chargé de réaliser des études de marché et autres activités inhérentes à une zone électrique particulière, tel que défini dans le Code de planification.
Supervisory Control and Data Acquisition	SCADA	means a system of remote control and telemetry used to monitor and control a Power System. It comprises computers, networked data communications and graphical user interfaces (GUI) for high-level process supervisory management.	324	Réglage et acquisition de données	SCADA	Désigne un système de contrôle à distance et de télémétrie utilisé pour surveiller et contrôler un Système électrique. Il comprend des ordinateurs, des communications de données en réseau et des interfaces utilisateur graphiques (GUI) pour une gestion de supervision de processus de haut niveau.
Suspension		it has the meaning given to it in MC 1.10.8 of the Market Code.	325	Suspension		a la signification qui lui a été attribuée dans le MC 1.10.8 du Code du marché.
Synchronization Leader		means the Grid Operator in charge of coordinating the Frequency Leaders in case of first synchronization among two or more asynchronous Power Systems or during the resynchronization process of two (2) adjacent Grids and executing the resynchronization.	326	Pilote de la synchronisation		désigne le Gestionnaire de réseau chargé de coordonner les pilotes de la fréquence en cas de première synchronisation entre deux ou plusieurs Systèmes électriques asynchrones ou pendant le processus de resynchronisation de deux (2) Réseaux de transport adjacents et exécutant la resynchronisation.
Synchronous Area		means a portion of the WAPP Power System composed of synchronously interconnected Grids.	327	Zone synchrone		désigne une partie du Système électrique de l'EEEOA composée de Réseaux de transport interconnectés de manière synchrone

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Synchronous Area Adequacy Coordinator		means designated Grid Operator for each Synchronous Area acting as Area Coordinator of Planning of a Synchronous Area, as per OC 6.9.	328	Coordonnateur de l'adéquation de la zone synchrone		Fait référence au Gestionnaire de réseau désigné pour chaque Zone synchrone en tant que coordonnateur de la planification pour cette Zone synchrone, conformément au OC 6.9.
Synchronous Generation Unit		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.	329	Unité de production synchrone		désigne un ensemble indivisible d'installations pouvant générer de l'énergie électrique de manière à ce que la fréquence de la tension générée, la vitesse du générateur et la fréquence de la tension du Réseau soient dans un rapport constant et donc de manière synchrone.
Synthetic Inertia		means the electronic Facility provided by an Inverter-based Generation Unit or HVDC System to emulate the effect of physical inertia of a synchronous Generation Unit.	330	Inertie synthétique		désigne l'installation électronique fournie par une Unité de production à onduleur ou un Système CCHT pour remplacer l'effet de l'inertie physique d'une Unité de production synchrone.
System Adequacy Forecast		As defined in Operation Code OC 6.1.5	331	Prévisions d'adéquation du système		Comme défini dans le Code d'opération OC 6.1.5.
System Market Operator	SMO	It refers to the regional Entity responsible for Regional Electricity Market operation functions and some system operation functions related to the WAPPITS.	332	Opérateur du Système-Marché	OSM	Désigne l'Entité régionale responsable des fonctions d'exploitation du Marché régional de l'électricité et de certaines fonctions d'exploitation du système liées au RTIE.
System Operator	SO	means an Entity that is charged with the Functional Operation of the Power System and the Cross-Border Interconnection.	333	Opérateur du Système	OS	désigne une Entité chargée de l'exploitation fonctionnelle du Système électrique et des interconnexions transfrontaliers.
System State		is synonymous to Operating Condition.	334	État du réseau		est synonyme de condition de fonctionnement.
Tertiary Control		means a centralized function to regulate the Generation based on Tertiary Reserves.	335	Réglage tertiaire		désigne une fonction centralisée de régulation de la production basée sur les réserves tertiaires.
Tertiary Reserve or Replacement Reserve		means the Replacement Reserve.	336	Réserve Tertiaire ou Réserve de remplacement		désigne la Réserve de remplacement.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Total Harmonic Distortion	THD	means ratio of the root means square (r.m.s.) value of the harmonic content to the r.m.s. value of the fundamental component or the reference fundamental component of an alternating quantity.	337	Distorsion harmonique totale	THD	désigne le rapport de la valeur efficace du contenu harmonique à la valeur efficace de la composante fondamentale ou de la composante fondamentale de référence d'une grandeur alternative.
Total Transfer Capacity	TTC	means the maximum exchange [MW] programmed between two LFC Areas compatible with Operational security standards applicable at each Power System if future Grid conditions, the Generation and Demand patterns are perfectly known in advance.	338	Capacité totale de transfert	TTC	désigne l'échange maximum [MW] programmé entre deux zones LFC conformes aux normes de sécurité d'exploitation applicables à chaque Système électrique, si les conditions futures du Réseau de transport, les modèles de production et de charge ou consommation sont parfaitement connus à l'avance.
Trading Interval		means a period of one (1) hour for the transactions in the Regional Electricity Market.	339	Intervalle de négoce		Désigne une période d'une (1) heure pour les transactions sur le Marché régional d'électricité.
Trading Limit		means the Credit Limit, or Credit Support of the market participant less a Prudential Margin, whichever of the two is lower.	340	Limite de négoce		Désigne le plus faible montant entre la limite de crédit d'un Participant au marché ou son Soutien au crédit diminué d'une marge prudentielle
Trading Margin		Means the amount by which the Market Participant's Trading Limit exceeds its Outstanding Amount within a given time.	341	Marge de négoce		Désigne, à tout moment, le montant par lequel la Limite de négoce d'un Participant au marché dépasse son encours.
Trading on Behalf		means a service provided to support a Market Participant for its participation in the Day-Ahead Market, in case where the cause of its non-participation in the market is not due to a technical malfunction of the ETS system.	342	Négoce pour le compte d'un tiers		Désigne le service fourni pour soutenir les Participants au marché pour leur participation au Marché du jour pour le lendemain, dans les cas où les causes ne sont pas dues à un dysfonctionnement technique du système ETS.
Trading Timeline		means timeline during which the Market Participants can submit Offers and Bids to the ETS in the Day-Ahead Market.	343	Chronologie de négoce		Désigne la période pendant laquelle les participants au marché peuvent soumettre des offres de ventes et des offres "achats sur l'ETS dans le marché du jour pour le lendemain.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Training Entities		means, in the Operators' Training Code, the entities providing training to the Grid Operators' personnel, including, but not limited to Grid Operators personnel itself, the SMO, experts from academia, consultants.	344	Entités de formation		désigne, dans le Code de formation des opérateurs, les Entités assurant la formation du personnel des Gestionnaires de réseau, y compris, mais sans s'y limiter, le personnel des Gestionnaires de réseau lui-même, l'OSM, les experts du monde universitaire, les consultants.
Transitional Provisions Framework		means the regulatory framework introduced in the General Conditions to allow each Member State to achieve the full compliance with the REM Codes provisions, according to each specific country situation in terms of technical progress in the matters of Transmission System development and operation.	345	Cadre des dispositions transitoires		désigne le cadre réglementaire énoncé dans les Conditions générales pour permettre à chaque État membre de se conformer pleinement aux dispositions des Codes du MRE, en fonction de la situation spécifique de chaque pays en termes de progrès technique en matière de développement et d'exploitation du Réseau de transport.
Transmission Operator	TO	means an Entity that owns the whole or part of the Grid assets, and it is responsible for the Physical Operation, the security, and maintenance of the Grid assets.	346	Opérateur de Transport	OT	désigne une Entité détenant tout ou partie des actifs du Réseau de transport, et qui est responsable de l'Opération physique, la sécurité et la maintenance des actifs du Réseau de transport.
Transmission Reliability Margin	TRM	means that amount of TTC necessary to ensure that the interconnected Transmission System is secure under a reasonable range of uncertainties in system conditions, that may arise from: 1. Inadvertent deviations of physical flows during operation due to the functioning of Secondary Control; 2. Emergency exchanges between Grid Operators to cope with unexpected imbalance situations in real-time; 3. Inaccuracies, e.g. in data collection and measurements.	347	Marge de fiabilité de Transport	TRM	désigne la quantité de TTC nécessaire afin de s'assurer que le Réseau de transport interconnecté soit sécurisé dans une plage d'incertitudes raisonnable et dans les conditions du système, susceptible de provenir de : 1. écarts fortuits des flux physiques pendant l'exploitation en raison du fonctionnement du réglage secondaire ; 2. échanges d'urgence entre les Gestionnaires de réseau pour faire face en temps réel à des situations déséquilibrées imprévues ; 3. imprécisions, par exemple dans la collecte de données et les mesures.
Transmission System Operator	TSO	means an Entity that combines the functions of System Operator and Transmission Operator.	348	Gestionnaire de Réseau de Transport	GRT	désigne une Entité qui combine les fonctions d'Opérateur de système et d'opérateur de transport.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Transmission System or Grid		means all HV lines and related equipment for the transmission of electricity, which facilitate delivery to eligible customers or to distributors. When the term is used to identify the Transmission System of a Control Area or a national Power System, the term shall refer to the HV Network with respect to which a relevant Grid Operator has authority to direct operations.	349	Réseau de transport		Toutes les lignes à haute tension et les équipements associés pour le transport d'électricité, qui facilitent la livraison aux clients éligibles ou aux distributeurs, dans le cadre d'échanges d'électricité transfrontaliers. Lorsque le terme est utilisé pour identifier le Réseau de transport d'une Zone de réglage ou à un Système électrique national, le terme renvoie au réseau à haute tension pour lequel le Gestionnaire de réseau concerné a le pouvoir de diriger l'exploitation.
Unavailability Coordination or Outage Coordination		means a structured process of inter Grid Operator coordination to align the proposed unavailability and optimize time and duration of the resulting unavailabilities. It is a sub process of the Outage Planning Coordination Business Process.	350	Coordination des indisponibilités ou Coordination des pannes		désigne un processus structuré de coordination entre Gestionnaires de réseau visant à synchroniser l'indisponibilité proposée et optimiser le temps et la durée des indisponibilités résultantes. C'est un sous-processus du Processus de coordination de la planification des indisponibilités.
Unavailability Plan		means an optimized schedule of unavailability of Elements of the Grid and Generation Facilities.	351	Plan d'indisponibilité		désigne un calendrier optimisé d'indisponibilité des éléments du Réseau de transport et des Installations de production.
Under Voltage Load Shedding	UVLS	means a safety measure to prevent widespread voltage collapse in the event of a severe deficit in local or system-wide area reactive power Reserves.	352	Délestage de charge sur tension basse	UVLS	désigne une mesure de sécurité destinée à empêcher toute chute grave généralisée de tension en cas de déficit grave des réserves de puissance réactive locale ou à l'échelle du système.
Underfrequency Load Shedding	UfLS	means a practice adopted to shed Loads by means of relays driven by frequency or its derivative.	353	Délestage de charge sur fréquence basse	UfLS	désigne une pratique adoptée pour délester des Charges via les relais déclenchés par la fréquence ou ses dérivés.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Union for the Coordination of the Transmission of Electricity	UCTE	means the Union for the Co-ordination of Transmission of Electricity, which coordinated the operation and development of the electricity Transmission System for the Continental European synchronously operated Transmission System, thus providing a reliable platform to all participants of the internal electricity market and beyond. It operated from 1951 to 2009, when all operational tasks were transferred to ENTSO-E.	354	Union for the Coordination of the Transmission of Electricity (Union pour la coordination du transport d'électricité)	UCTE	désigne l'Union pour la Coordination du Transport de l'Électricité, ayant coordonné l'exploitation et le développement du Réseau de transport d'électricité pour le Réseau de transport à fonctionnement synchrone de l'Europe continentale, offrant ainsi une plateforme fiable à tous les acteurs du marché intérieur de l'électricité et au-delà. Elle est restée active de 1951 à 2009, année durant laquelle toutes les tâches opérationnelles ont été transférées à l'ENTSO-E.
Unpublished Price Sensitive Information		as defined in MC 21.2.4	355	Informations non-publiées sensibles en matière de tarifs		tel que défini dans le MC 21.2.4
Upward Reserve		means the capacity to increase the Generation till the maximum technical output of the Generation Facilities. The available Reserve is the difference between the cumulated maximum technical output of Generation Facilities and the Demand. The term Upward, associated to a specific type of Reserve, is defined accordingly.	356	Réserve à la hausse		désigne la capacité d'augmenter la production jusqu'à la capacité technique maximale des Installations de production. La réserve disponible est la différence entre la capacité technique maximale cumulée des Installations de production et la Demande. Le terme à la Hausse, associé à un type spécifique de réserve, est défini en conséquence.
Use It or Lose It	UIOLI	means that if an acquired right is not exercised as at and when agreed, the right is lost, and no compensation is foreseen	357	Utilisé ou perdu	UIOLI	désigne que si un droit acquis n'est pas exercé comme et quand il a été convenu, le droit est perdu, et aucune compensation n'est prévue.
Validated Quantities		means the data that has been processed according to the VEE rules and found to be consistent without errors and ready to be used for the analysis, settlement, billing, reporting or decision-making processes.	358	Quantités validées		désigne les données qui ont été traitées par les règles VEE, qui sont cohérentes et sans erreurs et qui sont prêtes à être utilisées pour les processus d'analyse, de règlement, de facturation, de déclaration ou de prise de décision.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
Validation, Estimation and Editing	VEE	means the process implemented to detect and correct anomalies in data before it is used for processing, analysis, settlement, billing, reporting or decision-making processes.	359	Validation, estimation et édition	VEE	désigne le processus mis en œuvre pour détecter et corriger les anomalies dans les données avant qu'elles ne soient utilisées pour les processus de traitement, d'analyse, de règlement, de facturation, de déclaration ou de prise de décision.
Variable Renewable Energy Source	VRES	means a subset of RES that is non-dispatchable as primary energy sources, for instance, wind, solar, run-of-the-river hydroelectricity, tidal energy, wave energy, etc.	360	Source d'Énergie Renouvelable Variable	EnRV	désigne un sous-ensemble de EnR, c'est-à-dire les EnR non programmables en tant que sources d'énergie primaire : éolienne, solaire, hydroélectricité au fil de l'eau, marémotrice, houlomotrice
Verification Process		means the process of verifying that the Aggregated Netted Grid Operator External Schedules sum to zero within the same Synchronous Area.	361	Processus de vérification		désigne la vérification des plannings d'exploitations de réseau externe agrégé devant atteindre zéro dans la zone Synchrone.
Voltage Transformer	VT	means an Instrument Transformer in which the secondary voltage, in normal conditions of use, is substantially proportional to the primary voltage and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections ³ .	362	Transformateur de Tension	TT	désigne un Transformateur de mesure dans lequel la tension secondaire est, dans les conditions normales d'emploi, pratiquement proportionnelle à la tension primaire et déphasée par rapport à celle-ci d'un angle approximativement nul pour un sens approprié des connexions ³ .
WAPP Communication Network		means the private network dedicated to Data Exchange among Grid Operators and SMO and which is operated under the responsibility of the Grid Operators and the management of SMO.	363	Réseau de communication de l'EEEOA		Désigne le réseau privé dédié à l'échange de données entre les Gestionnaires de réseau, et fonctionnant sous la responsabilité des Gestionnaires de réseau et la gestion de l'OSM

³ According IEC 60050 International Electrotechnical Vocabulary

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
WAPP Interconnected Transmission System	WAPPITS	means all the transmission assets that form the regional Network as so defined and agreed upon by the countries. These assets are the regional interconnectors; the regional lines owned by special purpose companies and the transmission lines of the domestic Power Systems designated as forming part of the regional transmission Network.	364	Réseau de transport interconnecté de l'EEEOA	RTIE	Désigne l'ensemble des actifs de transport qui forment le Réseau régional défini comme tel et agréé par les pays. Ces actifs sont les interconnexions régionales, les lignes régionales détenues par des sociétés à objectifs spécifiques et les lignes de transport des Systèmes électriques domestiques conçues comme faisant partie du Réseau de transport régional.
WAPP Member		means any Entity that has met eligibility requirements as defined in Article 9 of the Articles of Agreement for the WAPP Organization and admitted as a member.	365	Membre de l'EEEOA		désigne toute Entité ayant rempli les conditions d'éligibilité telles que définies à l'article 9 des Statuts de l'organisation EEEOA et admis comme un membre.
WAPP Power System		means the integration of the Power Systems that comprise of all Generation, Demand and Network installations interconnected throughout the Networks operated by Grid Operators.	366	Système électrique de l'EEEOA		désigne l'intégration des Systèmes électriques qui comprennent toutes les Installations de production, de consommation et de Réseau interconnectées à travers les Réseaux exploités par des Gestionnaires de réseau.
WAPP Secretariat		means the administrative and technical organ in charge of the day-to-day management of the activities of WAPP.	367	Secrétariat de l'EEEOA		désigne l'organe administratif et technique chargé de la gestion quotidienne des activités de l'EEEOA.
Warning System	WS	means synoptical pages of the displays showing synthetic information to be shared among Grid Operators of an area to make aware Grid Operators about the status of the Grids and warn about emergencies.	368	Système d'alarme	WS	désigne des pages synoptiques des affichages contenant des informations concises à partager entre les Gestionnaires de réseau d'une zone afin d'informer ces Gestionnaires de l'état des Réseaux de transport et les avertir des urgences.
West African Electricity Market Information System	WAEMIS	means the information system and standard procedures for information collection and sharing in the Regional Electricity Market.	369	Système d'information sur le marché de l'électricité en Afrique de l'Ouest	WAEMIS	Le système d'information et les normes de conduite pour la collecte et le partage d'informations sur le Marché régional de l'électricité.

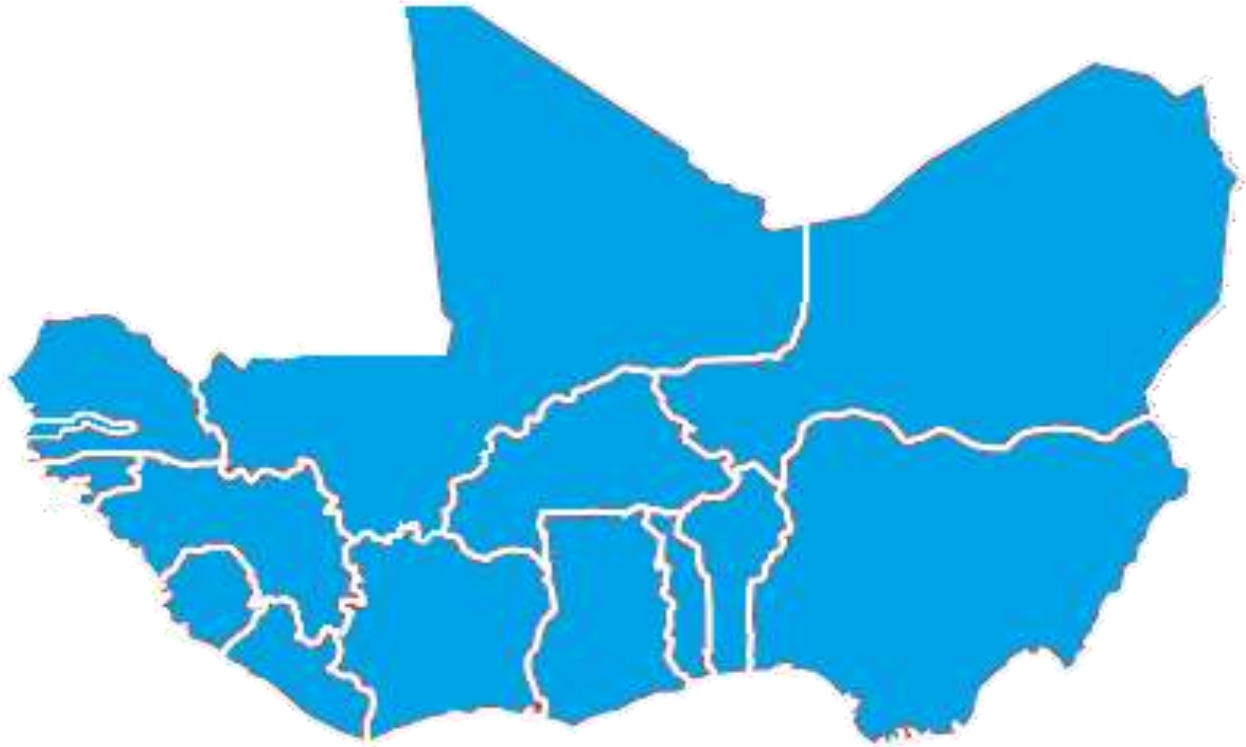
Term	Acronym	Definition	N°	Terme	Acronyme	Définition
West African Power Pool	WAPP	the term West African Power Pool refers to WAPP as a system or WAPP as an organisation. The WAPP system or WAPP is the system established by Decision A/DEC.5/12/99 of December 10, 1999, of the Authority of Heads of State and Governments, to provide an appropriate framework for development of energy production facilities, the interconnection of electricity Grids, the realization of regional investments and the development of energy exchange in west Africa. The WAPP organization or WAPP is the specialized institution of ECOWAS established by Decision A/DEC.20/01/06 of January 12, 2006, by the Authority of Heads of State and Governments, for the realization of the WAPP system and whose management structure is instituted by the Articles of Agreement of July 6, 2006 as amended. In these REM Codes, the term WAPP, as organisation is specified when the text refers to a function that pertains to or a decision to be taken by the WAPP Organization and/or any of its governing structure.	370	Système d'Échanges d'Énergie Électrique de l'Ouest Africain	EEEOA	Le terme système d'Échanges d'Énergie Électrique Ouest Africain désigne l'EEEOA en tant que système ou l'EEEOA/ WAPP en tant qu'organisation. Le terme EEEOA, système d'Échanges d'Énergie Électrique Ouest Africain désigne le système mis en place par la Décision A/DEC.5/12/99 du 10 décembre 1999, de la Conférence des Chefs d'État et de gouvernement, pour préparer et mettre en place le cadre propice pour le développement des moyens de production d'énergie électrique, l'interconnexion des réseaux électriques, la réalisation des investissements régionaux et le développement des échanges énergétiques en Afrique de l'Ouest. Le terme EEEOA désigne l'organisation du système d'Échanges d'Énergie Électrique Ouest Africain, une institution spécialisée de la CEDEAO créée par la Décision A/DEC.20/01/06 du 12 janvier 2006, de la Conférence des Chefs d'État et de gouvernement, pour la mise en œuvre du système d'échanges d'énergie électrique ouest africain et dont les structures de gestion sont instituées par la Convention du 6 juillet 2006 telle qu'amendée. DANS les présents Codes du MRE, le terme EEEOA est employé, en tant qu'organisation, lorsque le texte se réfère à une fonction relevant de l'Organisation de l'EEEOA et/ou à une décision devant être prise par celle-ci ou par l'une de ses structures de gouvernance.
WG1- Outage Planning Coordination Working Group	WG1	means a Working group tasked to design, maintain and monitor processes of the Outage Planning Coordination Business Process, as per OC 1.7.	371	GT1 - Groupe de Travail sur la Coordination de la planification des indisponibilités	GT1	désigne un groupe de travail chargé de concevoir, maintenir et surveiller les processus de coordination de la planification des indisponibilités, conformément au OC 1.7.

Term	Acronym	Definition	N°	Terme	Acronyme	Définition
WG2-Operation Working Group	WG2	means a Working group tasked to design, maintain and monitor processes of the real-time Operation, as per OC 1.7.	372	GT2 - Groupe de Travail sur l'exploitation	GT2	désigne un groupe de travail chargé de concevoir, maintenir et surveiller les processus d'exploitation en temps réel, conformément au OC 1.7.
WG3-ICT Working Group	WG3	means a Working group tasked to design, maintain and monitor processes and tools in matter of ICT, as per OC 1.7.	373	GT3 - Groupe de Travail ICT	GT3	désigne un groupe de travail chargé de concevoir, maintenir et contrôler les processus et outils en matière d' ICT, conformément au OC 1.7.
WG4-Planning Working Group	WG4	means a Working group tasked to support the drafting of the WAPP Master Plan, as per PC 2.2.	374	GT4 - Groupe de Travail sur la planification	GT4	désigne un groupe de travail chargé de soutenir l'élaboration du Plan directeur de l'EEEOA, conformément au PC 2.2.
Wide Area Monitoring System	WAMS	means real time synchrophasor-based measurement and monitoring system for enhanced situational awareness, improved visibility and proactive Grid management.	375	Système de mesure à zone étendue	WAMS	désigne un système de mesure et de surveillance en temps réel basé sur un synchrophaseur utilisé pour améliorer la connaissance de l'état du réseau, améliorer la visibilité et une gestion proactive du Réseau de transport.
Wide Area Network	WAN	means a Network that provides communication services to a large geographic area.	376	Réseau étendu	WAN	désigne un Réseau capable d'assurer des services de communication à une large zone géographique.
Wide Area Protection System or Special Protection Scheme	WAPS	means a protection system adopted to protect a Power System from a partial or total blackout or brown-out in operational situations when no equipment is faulted or operated outside its limitations. This situation may arise after the elimination of a very serious fault during a period of operation under constraints, or during a period of sharply increased consumption.	377	Dispositifs de protection spéciaux	WAPS	désigne un système de protection adopté pour protéger un Système électrique contre une coupure de courant partielle ou totale, ou une baisse de tension, dans des cas d'exploitation où aucun équipement n'est défectueux ou exploité en dehors de ses limites. Cette situation peut survenir après l'élimination d'un défaut très sévère lors d'un période d'exploitation sous contraintes ou lors d'une période de de forte augmentation de la consommation.
Withdrawal Point		means the point in the Transmission System where the Buyer is withdrawing its electricity consumption from the national Grid.	378	Point de soutirage		désigne le point du Réseau de transport où l'Acheteur retire sa consommation d'électricité du Réseau de transport national.

GD 2. SYMBOLS AND UNITS OF MEASUREMENT

Symbol	Variable	Units of Measurement
Δf	Frequency deviation of the Transmission System	[Hz] or [p.u.]
ΔP	Variation of active power output	[MW]
f	Frequency	[Hz] or [p.u.]
f_n	Nominal Frequency	[Hz] or [p.u.]
P	Active power	[MW]
P_{lt}	Long-term flicker severity	[-]
P_{MAX}	Generation Capacity - i.e. maximum active power output of a Generation Unit	[MW]
P_{st}	Short-term flicker severity	[-]
Q	Reactive Power	[Mvar]
s	Droop of a Synchronous Generation Unit or HVDC System	[%]
t_1	Maximum admissible initial delay of active power response capability	[s]
t_2	Full activation time of active power response capability	[s]
t_{rec}	Time series to build the Fault-Ride-Through capability curve for Generation Units and HVDC Systems	[ms]
U	Voltage	[V] or [p.u.]
U_{ret}	Voltage series to build the Fault-Ride-Through capability curve for Generation Units and HVDC Systems	[p.u.]
U_{rec}		
ξ_1, ξ_2	Maximum error within which the control system of Generation Units must control the active power with respect to constant target values (ξ_1) and during changes in the target value (ξ_2).	[%]

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



GC – GENERAL CONDITIONS

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GC 1. OBJECTIVE

GC 1.1.1 The **REM Codes** govern the development and operation of the **Regional Electricity Market (REM)** and provides the general rules based on set of principles governing the status, the operation, and the development of **WAPP Power System**. These principles are:

- a) Solidarity: the commitment to support the neighbouring **Power Systems** as long as the security of its own **Power System** is not at stake.
- b) Transparency: **WAPP Members** commit to share **Information** and data in accordance with the rules and obligations of the **REM Codes**.
- c) Proportionality: the actions of **WAPP** and the **Grid Operators** must be limited to what is necessary to achieve the objectives of the **Member States**.
- d) Security: **Grid Operators** commit to operate their **Grid** in a manner that would not hamper the security of neighbouring **Power Systems**.
- e) Autonomy: each **Grid Operator** shall react to contingencies with its own resources first and bring back the exchanges within the scheduled values after any **Imbalances**.
- f) Environmental Sustainability: all involved **Entities** shall take the commitment to give priority and use their **Best Efforts** for maximising the accommodation of **Renewable Energy Sources** in their **Power Systems**.

GC 1.1.2 The **REM Codes** also aim at fostering the development of the **WAPP Power System**, the security of supply and the **REM** operation for the benefit of the consumers.

GC 1.1.3 The **REM Codes** are part of the **Regional Electricity Market Regulation (REMR)**.

GC 1.1.4 The **REMR** governs legal, technical and commercial aspects of regional trade towards the implementation of the **REM**, led by **ERERA** under the **ECOWAS** guidelines.

GC 1.1.5 Once approved, the **REM Codes** will form an integral part of the **REMR**.

GC 1.1.6 The **REM Codes** include the following contents:

- a) **Glossary and Definitions (GD)**.
- b) **General Conditions (GC)**.
- c) **Planning Code (PC)**.
- d) **Operation Code (OC)**.
- e) **Connection Code (CC)**.
- f) **Market Code (MC)**.
- g) **Metering Code (MTC)**.

h) **Operators' Training Code (OpTC).**

GC 1.1.7 Unless otherwise requested in the specific articles of the **REM Codes**, the acceptable means of written communication are: messages to/from the **SMO's** messaging system, official e-mail addresses of any **Entity** involved in the **REM**, official Fax addresses of any **Entity** involved in the **REM**, paper-based registered mails signed by the relevant responsible person of any **Entity** involved in the **REM**.

GC 2. SCOPE OF APPLICATION

GC 2.1.1 The **REM Codes** apply to the coordination, the development and the operation of the interconnected **Power Systems** of the **Member States**, and the **Regional Electricity Market (REM)**, safeguarding security and generating economies of scale.

GC 2.1.2 The adoption of **Operational Procedures** consistent with the **REM Codes** is the responsibilities of the national **Grid Operators** and the **Electricity Supply Industry (ESI)** since their definition is the outcome of multilateral agreements and negotiations among the involved parties.

GC 2.1.3 The adoption of the **REM Codes** is mandatory in the territories of the **Member States**. In particular:

- a) The **Governing Institutions** shall ensure consistency of the regional and national regulations with the contents of the **REM Codes**.
- b) National **Grid Operators** shall ensure consistency of the **National Grid Codes** and their functional processes with the provisions of the **REM Codes**.
- c) Domestic **Electricity Supply Industry** shall comply with the **REM Codes**.

GC 2.1.4 The **REM Codes** provide a **Transitional Provisions Framework** (GC 9.4.3) to allow each **Grid Operator** of the **Member States** to achieve the full compliance with the **REM Codes** provisions, according to each specific country situation in terms of technical progress in the matters of **Transmission System** development and **Operation**.

GC 2.1.5 The **Transitional Provisions Framework** is based on the following items:

- a) The concept of **Grid Operator Temporary Non-compliance** as outlined in GC 9.4.1 and GC 9.4.2;
- b) The **Inter-Grid Operators Agreement** (GC 9.4.3) which is as a declaration of the commitment of each **Member State** in implementing actions towards the full compliance with the **REM Codes**;
- c) The **Addendum to the Inter-Grid Operators Agreement** (GC 9.4.4), where each **Member State** arranges to list the **Grid Operator Temporary Non-compliances** (if any) at the moment of approval of the **REM Codes** and to provide a roadmap to solve them. The

Addendum to the Inter-Grid Operators Agreement also entails actions aimed at adapting national regulations to the provisions of the **REM Codes**.

- d) The **Compliance Continuous Monitoring** (GC 9.4.5) to assess the progress of each **Member State** according to the related **Addendum to the Inter-Grid Operators Agreement**.

GC 2.1.6 The **Grid Operators** shall proactively cooperate in deploying the provisions of the **REM Codes**. To this purpose, **Grid Operators** shall work for the harmonization of practices without jeopardizing the **Security of Operation** and putting in place the following actions, at least:

- a) Providing high level technical support to **WAPP**, and to the **Member States** if required, in the discussions for drafting, amending, issuing and approving the **REM Codes** and in proposing future improvement.
- b) Taking part to the process that aims at drafting procedures and the related designing steps to complement the **REM Codes** with required detailed application documents.
- c) Striving for consensus when discussing and approving documents.
- d) Declaring the **Grid Operator Temporary Non-compliances** and devise a plan to overcome them.
- e) Accepting and supporting the **Compliance Continuous Monitoring**.
- f) Taking proper measures to adapt national regulations (e.g. national laws in force, **National Grid Codes** and **Grid Operator** internal procedures) to the provisions of the **REM Codes**.

GC 2.1.7 The **Grid Operators** may facilitate the coordination in the operation through the establishment of coordination **Entities**. In this case, such **Entities** are also subject to the **REM Codes**. They are also admitted to the works of the relevant committees and must contribute to the coordination of centralized functions.

GC 3. APPROVAL OF THE REM CODES

GC 3.1 Principles

GC 3.1.1 **WAPP** is the **Entity** in charge of:

- a) managing the technical aspects of the **REM Codes**;
- b) drafting and proposing amendments of the **REM Codes**;
- c) coordinating with **ERERA** for the approval and the enforcement of the **REM Codes**.

GC 3.1.2 The **REM Codes** are subject to the approval of **ERERA**.

- GC 3.1.3 The approved **REM Codes** shall be mandatory for **Member States**, subject to article GC 3.1.4.
- GC 3.1.4 Within twelve (12) months after the approval of the **REM Codes** by **ERERA**:
- a) the **Inter-Grid Operators Agreement** shall be executed by each **Member State** as per ANNEX B –INTER-GRID OPERATOR AGREEMENT OUTLINE;
 - b) the **Addenda to the Inter-Grid Operators Agreement** shall be edited and subscribed by each **Member State** as per ANNEX C – CONTENTS OF THE ADDENDUM;
 - c) the **Compliance Evaluation Group** is established as per ANNEX D – COMPLIANCE CONTINUOUS MONITORING.
- GC 3.1.5 The **Member States** may decide, according to the decision-making rules of **ECOWAS**, to postpone the implementation of the **REM Codes** for one or more **Member States** in order to grant to them the time deemed necessary to meet the minimum requirements. In this case, **ERERA** will analyse the request and grant a grace period. Accordingly, all the obligations as per article GC 3.1.4 apply at the end of the grace period.

GC 4. MODIFICATION OF THE REM CODES

GC 4.1 General Provisions on Amendments

- GC 4.1.1 The provisions of the **REM Codes** may only be amended when the applicable procedures set forth in this GC 4 have been followed.
- GC 4.1.2 An amendment to the **REM Codes** becomes effective only upon:
- (1) review and validation by **WAPP**, and
 - (2) approval by **ERERA**, according to the procedures set forth in this GC 4.
- GC 4.1.3 An amendment can be proposed by the **Governing Institutions** or an **Entity** within the **Electricity Supply Industry** according to the procedures set forth in this GC 4.
- GC 4.1.4 In formulating and reviewing an amendment to the **REM Codes**, **ERERA** and **WAPP** shall take into consideration the objectives of the **REM** as set forth in **ECOWAS** guidelines and resolutions.

GC 4.2 Initiation of Amendments

- GC 4.2.1 A **Governing Institution** or/and any **Entity** within the **Electricity Supply Industry** may file an amendment submission to **WAPP** to propose one or more amendments to the **REM Codes**.

- GC 4.2.2 The amendment submission shall include a statement of the reasons why an amendment is deemed necessary or desirable.
- GC 4.2.3 **WAPP** may request that the **Entity** proposing the amendment submission provides further details.
- GC 4.2.4 **ERERA** shall manage the process of amendments according to definite procedures and according to the following general terms:
- a) After receiving the request for amendment submitted by **WAPP**, **ERERA** shall Publish a regulatory report, which is initially a working document which is updated gradually with the progress of the analysis of the requests and the proposals. The regulatory report is meant to be a report to be Published periodically by **ERERA** on critical matters arising in the **REM**.
 - b) **ERERA** shall identify improvements to the **REM Codes** and prescribe actions to remove issues associated with the **REM**. Without prejudice to prescribe changes in the interests of the consumers, **ERERA** shall propose, as necessary, recommendations for amendments to the **Market Participant Agreement**, as attached to the **Market Code**.
 - c) **ERERA** shall classify the list of proposed amendments as either minor or major. An amendment is considered minor if **ERERA** considers it not relevant from the economic point of view, beneficial for clarity of the **REM Codes**, and any other similar reason to be discussed case by case. An amendment is major in any other case.
- GC 4.2.5 In forming its analysis and recommendations in the regulatory report, **ERERA** shall take into consideration the amendment submissions of **WAPP**, as well as those generated by **ERERA** itself. The regulatory report shall include a copy of each amendment submission.
- GC 4.2.6 The **Market Participants**, the **Grid Operators**, the **Governing Institutions**, **Entities** in the **Electricity Supply Industry** and the **WAPP** have a period of four (4) weeks, or as determined by **ERERA**, from the time the regulatory report is Published to file written comments to **ERERA** as regard to the analysis and recommendations provided in article GC 4.2.5.
- GC 4.2.7 **ERERA**, after taking into consideration the views of the **Parties** that have filed amendment submissions or that have written comments about the regulatory report, shall Publish the final version of the regulatory report on the initiation of amendments within four (4) weeks of receipt of the comments in article GC 4.2.6 and subsequently share the report with ECOWAS for information purposes.
- GC 4.2.8 An explanatory flowchart showing the steps for the initiation of the amendments is displayed in Figure GC 1.

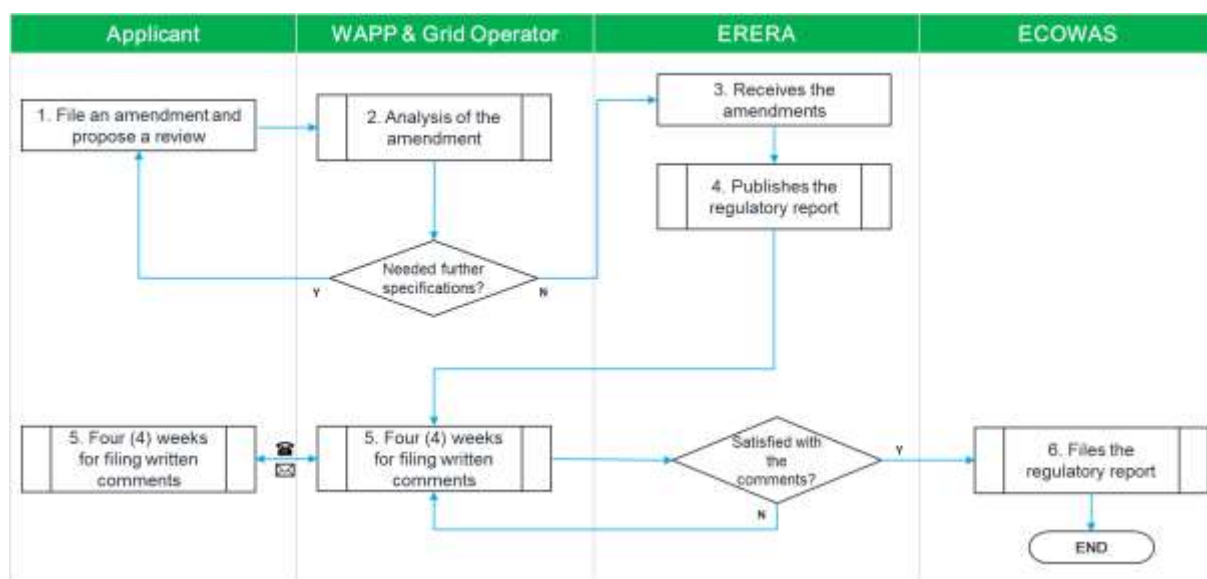


Figure GC 1 Flowchart of the steps for initiation of the **REM Codes** amendments

GC 4.3 Review and Approval of an Amendment to the REM Codes

GC 4.3.1 Following the publication of the final version of the regulatory report in article GC 4.2.7, **WAPP** shall review the proposed amendment and determine the appropriate procedure and timetable for analysis, evaluation and approval.

GC 4.3.2 When developing the procedure and timetable for the review, **WAPP** shall take into consideration the significance (i.e., minor vs major) and urgency of the proposed amendment as indicated by **ERERA**.

GC 4.3.3 When the proposed amendment is minor and/or relate to secondary documentation such as implementing documents of the **REM Codes**, the **WAPP** shall document the arguments related to the proposed amendment along with its decision and **Publish** its decision on its website. Once the amendment is approved by **ERERA**, , the amendment shall be **Published** and considered part of the **REM Codes**.

GC 4.3.4 When the proposed amendment is not minor, the **WAPP** will **Publish** the proposed amendment on its website for public enquiry, inviting written submissions concerning the matter by a specified date.

GC 4.3.5 Where in the opinion of **WAPP** there is consistency among the views expressed in the written submissions, it shall document the arguments related to the proposed amendment along with its recommendations and forward the documentation to **ERERA** for review and approval. Once approved by **ERERA**, the amendment shall be **Published** and considered part of the **REM Codes**.

GC 4.3.6 Where in the opinion of **WAPP** there is a diversity of views expressed in the written submissions, **WAPP** shall refer the request for amendment to **ERERA** and notify the **Market Participants**, the **Grid Operators**, the **Electricity Supply Industry** and the **Governing Institutions**. The notification shall include the documentation of the proposed amendment. **ERERA** shall within six (6) weeks of receipt of the notification, review and decide on the proposed amendments.

GC 4.3.7 Following the review, the decision of **ERERA** shall be **Published** on its website and shall include the proposed amendment and the reasons for the decision. The amendment shall be considered part of the **REM Codes**. Any decision taken by **ERERA** shall meet the objectives and principles, as per article GC 1.1.1, of the **General Conditions**.

GC 4.3.8 An explanatory flowchart of the steps for review and approval of an amendment is displayed in Figure GC 2.

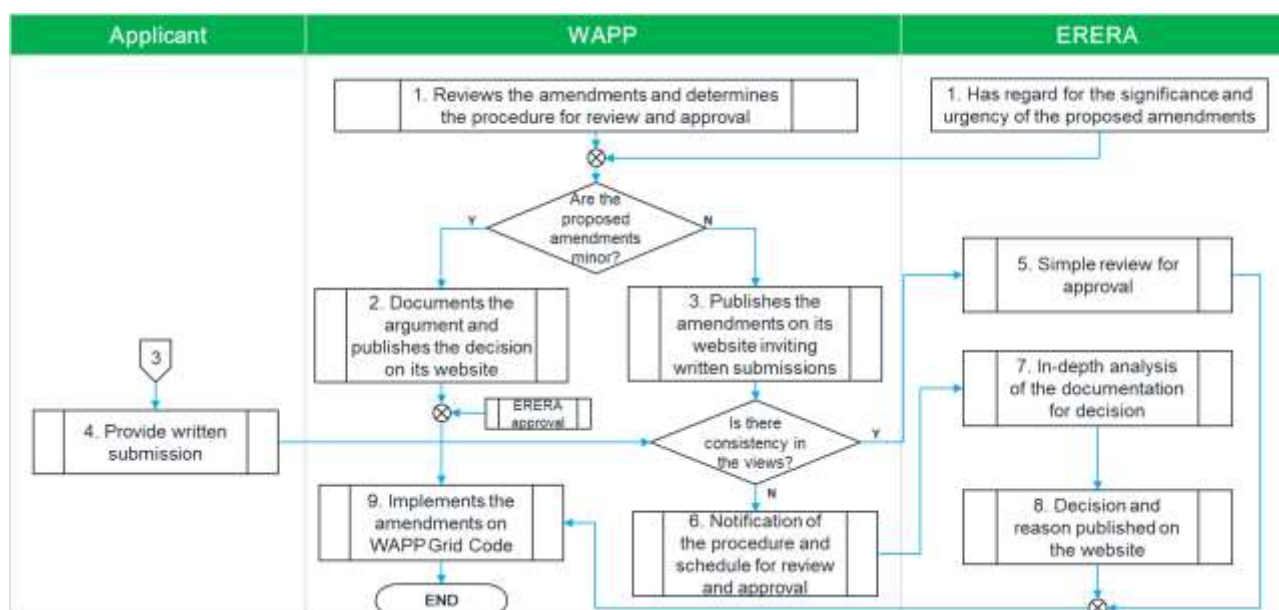


Figure GC 2 Flowchart of steps for review and approval of the **REM Codes** amendments.

GC 4.4 Experts and Other Assistance

GC 4.4.1 The **WAPP** and **ERERA** may hire consulting assistance and seek expert external advice as may be necessary or desirable for the purpose of the fulfilment of its responsibilities under GC 4.

GC 4.4.2 In carrying out any of its responsibilities under GC 4, the **WAPP** and **ERERA** may solicit the assistance of the **Grid Operators** and the **SMO**.

GC 4.5 Interpretation Bulletins

- GC 4.5.1 **ERERA** may, from time to time, upon receipt of material requests for clarification of the interpretation or application of provisions in the **REM Codes**, **Publish** bulletins as to the interpretation or application of such provisions. **ERERA** will give notice to the **Entity** which made the request and **Governing Institutions** of any bulletins so Published.
- GC 4.5.2 The process described in article GC 4.5.1 shall take into account the criticalities, if any, coming out of the **Compliance Continuous Monitoring** (ANNEX D – COMPLIANCE CONTINUOUS MONITORING) implemented by **WAPP**.

GC 5. INSTITUTIONAL STRUCTURE OF THE REM

- GC 5.1.1 The **REM Codes** follow the institutional structure created to regulate and operate the **REM**, and the identifications of the different classes of **Market Participants**, and their rights and obligations under the **Market Participant Agreement** and the **REM Codes**.
- GC 5.1.2 For referencing and **Information** purposes, the ANNEX A – INSTITUTIONAL STRUCTURE summarizes the main insights on this matter.
- GC 5.1.3 The **REM Codes** respect the degree of unbundling of the electricity sector that the **Member States** have undertaken or will undertake, considering the activities being undertaken by different **Entities** according to the degree of unbundling.

GC 6. UNFORESEEN CIRCUMSTANCES

- GC 6.1.1 Where circumstances occur, which are not contemplated by the provisions of the **REM Codes** and significantly affect its application, **ERERA** shall, to the extent reasonably practicable, consult with all affected **Electricity Supply Industry** to reach agreement as to what should be done.
- GC 6.1.2 Where an agreement, between **ERERA** and such **Electricity Supply Industry**, cannot be reached in a reasonable time, **ERERA** shall determine the best course of action according to the principle of **Good Utility Practice**.
- GC 6.1.3 Based on the best course of action determined in article GC 6.1.2, **ERERA** shall issue instructions consistent with the current national provisions of affected **Grid Operators** and other **Parties**.
- GC 6.1.4 The affected **Electricity Supply Industry** shall comply with all instructions given by **ERERA**.

GC 6.1.5 **ERERA** shall start the procedure of reviewing the **REM Codes** if needed.

GC 7. FORCE MAJEURE

GC 7.1.1 A **Force Majeure Event** shall be any event or circumstance, or combination of events or circumstances, beyond the control of any **Party**, which was not foreseeable, could not be prevented or overcome, and which prevents the **Party** from performing its obligations under the **REM Codes**.

GC 7.1.2 Where a **Force Majeure Event** occurs, the application of the **REM Codes** may be suspended, in whole or in part, with respect to the affected **Party**, in accordance with the directions issued by **ERERA**.

GC 7.1.3 The **Party** affected by a **Force Majeure Event** shall not be liable to any other **Party** for any failure or delay in fulfilling its obligations under the **REM Codes** to the extent that such failure or delay:

- a) results from the **Force Majeure Event**, for the duration of the **Force Majeure Event**, and for such reasonable period thereafter as may be required for the affected **Party** to resume performance of its obligation;
- b) would not have been experienced but for such **Force Majeure Event**.

GC 7.1.4 Where a **Force Majeure Event** prevents or delays a **Party** from performing any of its obligations under the **REM Codes**, that **Party** shall:

- a) promptly notify any other **Party** involved and **ERERA** of the **Force Majeure Event** within three (3) days from the date on which the **Party** becomes aware of the occurrence of the **Force Majeure Event**. The notice shall include:
 - i. the assessment, in good faith, of the nature of the **Force Majeure Event**;
 - ii. the effect the **Force Majeure Event** will have on its ability to perform any of its obligations;
 - iii. the measures the **Party** proposes to implement in order to alleviate the impact of the **Force Majeure Event**.
- b) not be entitled to suspend performance of any of its obligations under the **REM Codes** to any greater extent or for any longer time than the duration of the **Force Majeure Event**.
- c) use its **Best Efforts** to mitigate the effects of the **Force Majeure Event**, remedy its inability to perform, and resume full performance of its obligations.
- d) notify **ERERA** and the other **Parties** and as soon as practicable **Publish** notice of any material change in the Information contained in any previous notice given and **Published** pursuant to this GC 7.
- e) **Publish** notice to the other **Parties** of the cessation of the **Force Majeure Event** and when it resumes to perform any obligation affected by the **Force Majeure Event**.

GC 7.1.5 The **REM Codes** establish provisions that shall be observed when the **Power System** is in an **Emergency State**, and nothing in this GC 7 shall relieve a **Party** from performing its obligations required by these provisions.

GC 8. REQUIREMENTS FOR GRID OPERATORS TO INTERCONNECT WITH THE WAPPITS

GC 8.1.1 The interconnected operation within the **WAPP Power System** implies the compliance with the **REM Codes**, without prejudice to GC 9.4.3.

GC 8.1.2 **Grid Operators** of **Member States** shall take part in the **WAPP** committees and shall comply with the **REM Codes**.

GC 8.1.3 **Grid Operators** of the **Member States** shall ensure that users of the **Grid**, under their responsibility, comply with the **REM Codes**.

GC 8.1.4 Except for temporary connection for humanitarian reasons, **Grid Operators** of **Member States** shall not synchronously connect with the **Power Systems** of **Non-Member States**, without authorization of **WAPP**.

GC 8.1.5 Non-**WAPP** Grid Operator shall respect the following conditions in order to be allowed to be connected and/or work synchronously with the **WAPP Power System**:

- a) Acknowledge and ensure consistency of its jurisdictional regulations (e.g., **National Grid Codes**) and functional processes (e.g., internal procedures) with provisions of the **REM Codes**.
- b) Establish compliance with article GC 8.1.5a) and also pass a series of tests coordinated by **WAPP** and the **SMO**.
- c) Obtain **ERERA**'s no-objection for the interconnection.

GC 8.1.6 To become a **Grid Operator** (i.e., operator that is also **WAPP Member**), start the synchronous **Functional Operation**, and have the subsequent rights and duties, the designated operators of the utilities that are not **WAPP Members** and are not yet connected to the **WAPP Power System** are required to:

- a) have a formal mandate by their respective Governments.
- b) apply for membership on the basis of an interconnection project presented and shared with the relevant neighbouring **Grid Operator**.
- c) accept and subscribe the articles of agreements of **WAPP** as set forth in the **REMR**.
- d) Sign the **Inter-Grid Operator Agreement** as described in ANNEX B –INTER-GRID OPERATOR AGREEMENT OUTLINE.
- e) nominate the members to be represented at all the **WAPP** committees as observers without voting rights for at most nine (9) months after the fulfilment of all the previous point a) to d).

GC 8.1.7 Due to the fact that **Grid Operators** cannot guarantee the **Security of Operation** and **Security of Supply** irrespective of the performances of the **Facilities** run by the **Electricity Supply Industry**, **Grid Operators** shall regularly check and coordinate their **Electricity Supply Industry** to withstand normal or severe disturbances and to facilitate **Restoration** of the **Power System** after the collapse.

GC 9. DEROGATIONS AND GRID OPERATOR TEMPORARY NON-COMPLIANCES

GC 9.1 Derogation Definition

GC 9.1.1 A derogation is a right given by an **Entity** entitled to grant it (called the grantor) to another **Entity** (called the grantee) relieving the grantee from its obligation to comply with a technical requirement in specified circumstances and to a specified extent.

GC 9.1.2 The formal document that makes the derogation valid is called deliberation.

GC 9.1.3 The grantor may systematically review the derogation and monitor the progress towards compliance.

GC 9.1.4 **Grid Operators** and **WAPP** are the sole **Entities** entitled to grant derogations concerning technical matters, with the following constraints:

- a) **WAPP** is mandated to grant derogations to a **Grid Operator** subject to approval by the rest of the **Grid Operators**. The derogation shall be restricted to the application of the **REM Codes**.
- b) **Grid Operators** are authorized to grant derogations only to **Generation Facility Owners**, **DSOs**, and **Demand Facility Owners** connected to the **Networks** of their competence. The derogation shall be limited to the provisions of the National Grid Code relating to the operation of the **WAPP Interconnected Transmission System**.

GC 9.1.5 A derogation shall come into force from the effective date stated in the deliberation referred to in article GC 9.1.2.

GC 9.1.6 A derogation shall be granted to an individual **Entity** and cannot be transferred.

GC 9.1.7 Where an **Entity** has identified that it does not or will not in the future be able to comply with one or more obligations of the **REM Codes** it shall:

- a) communicate the lack of conformity to the relevant **Entity** responsible for the operation of the **Power System** to which it belongs;
- b) forward a written request to the relevant grantor for a derogation to comply with such obligation(s) as per the relevant derogation category.

GC 9.1.8 The following categories of derogation are considered:

- a) **Derogation A:** Derogations from a requirement of the **National Grid Code** requested by an **Entity** belonging to the **Electricity Supply Industry** that do not significantly impact the interconnection or are quantitatively compensated by the **Grid Operator** with equivalent resources. In this case, the grantor is the relevant **Grid Operator** and the derogation request is handled at national level under the **Grid Operator** responsibility.
- b) **Derogation B:** Derogations from a requirement of the **National Grid Code** requested by a **Entity** belonging to the **Electricity Supply Industry** that significantly impact the interconnection and cannot be quantitatively compensated by the **Grid Operator** with equivalent resources. In this case, the grantor is **WAPP** in cooperation with the relevant **Grid Operator**.
- c) **Derogation C (Grid Operator Temporary Non-compliance):** Derogation granted to a **Grid Operator** for non-compliance with operation practices and policies whose responsibility lies on **Grid Operators**, prescribed by the **REM Codes** and undersigned in the specific **Inter-Grid Operator Agreements** and **Addendum to the Inter-Grid Operators Agreement**. In this case, a **Grid Operator** is the applicant and **WAPP** is the grantor in charge of handling the matter and managing the **Transitional Provisions Framework**.

GC 9.1.9 In any type of derogation, the main aim is to provide transparent processes to enhance the harmonization of derogation processes among the **Member States**.

GC 9.1.10 **WAPP** shall initiate a revision of this GC 9 as may be required from time to time to reflect changes in the **REM Codes**, the **REMR** and respective processes.

GC 9.2 Norms applicable to Derogations A and B

GC 9.2.1 *Derogation Request*

GC 9.2.1.1 Continuous compliance with national technical requirements (i.e. **National Grid Code**) is the responsibility of each relevant affected **Entity**. Where an **Entity** belonging to the **Electricity Supply Industry** is unable to comply with any provision of the relevant code, it shall, without delay, report such condition to the relevant **Grid Operator** and request for a derogation from such provision.

GC 9.2.1.2 Typical circumstances which may require a derogation to prevent a breach of an affected **Entity's** obligation, are the following:

- a) when a **Facility** or part of it is to be restored to comply with a technical requirement;
- b) when changes to the national rules are made and revamping is technologically or economically critical;
- c) when out of range infrequent events occur causing serious challenges (e.g. under capacity of supply) for people;

- d) to allow performing on-site tests on new **Facilities**.

GC 9.2.2 ***Duration of the Derogation***

GC 9.2.2.1 Three (3) categories of derogation shall be considered:

- a) **Definite**: valid for a period specified in the deliberation.
- b) **Permanent**: valid for the lifetime of the equipment forming that **Facility** or part of it. In case of replacement of equipment or parts of **Facility**, a further derogation is made, or the derogation is revoked.
- c) **Indefinite**: if it is not possible to foresee the expiration date of the conditions which justify the derogation. The derogation is valid until a further deliberation of the relevant grantor revokes the same derogation.

GC 9.2.2.2 Indefinite derogation shall be issued in very limited circumstances specified by the relevant **Grid Operator**. **ERERA** may issue further directions that can vary or withdraw previous derogations.

GC 9.2.3 ***Information Required in a Derogation Request***

GC 9.2.3.1 The request shall include:

- a) Details of the applicant, including:
 - i. the full name, address and contact **Information** of the **Entity** seeking the derogation;
 - ii. a description of the **Entity** seeking the derogation including, where relevant, **Information** on the location of the relevant site for which the derogation is being applied for.
- b) A clear description of the non-compliance including:
 - i. relevant provisions of the **REM Codes / National Grid Code**;
 - ii. the required obligation;
 - iii. the current, actual capability of the **Element** or **Facility**
- c) A clear description of the reasons why the non-compliance has occurred or is expected to occur.
- d) A comprehensive and, wherever possible, quantitative assessment, of the impact of the non-compliance on:
 - i. Consumers.
 - ii. **Security of Supply**.
 - iii. **Security of Operation**.
 - iv. Competition.
 - v. Data reliability and data quality.
 - vi. Health and safety and the associated risk management measures.
 - vii. Other **Entities** affected by the non-compliance, including the ability to operate the **Power System**.

- e) Evidence that the requested derogations would have no adverse effect on cross-border electricity exchanges.
- f) Details of measures taken or to be taken to mitigate risks to consumers or other affected **Entities** while the non-compliance exists.
- g) A description of the proposal for restoring compliance (where applicable) including timetable of works.
- h) A description of the alternative actions that have been considered.
- i) The proposed duration of the derogation requested.
- j) All other **Information** on details of the requirement in question.

GC 9.2.3.2 All technical terms shall be fully and unambiguously explained, and the request shall be presented as clearly as possible to avoid unnecessary delays in the assessment of the request.

GC 9.2.3.3 The applicant shall:

- a) justify the derogation request in terms of both the specific circumstances and the expected duration;
- b) give as much notice as possible when making derogation requests since a derogation will not be granted unless the grantor is satisfied with the justification supporting the request;
- c) be promptly available to provide the grantor with further requests of Information;
- d) make its **Facility** available for assessments without prejudice to the confidentiality constraints.

GC 9.2.4 ***Assessment of Derogation Applications***

GC 9.2.4.1 Each derogation request shall be assessed by the grantor, individually on its merits, against transparent criteria.

GC 9.2.4.2 The grantor shall use its judgement in assessing any derogation requests within the limits hereinafter described and shall advise any applicant of additional Information requirements that were not included in the original request.

GC 9.2.4.3 The criteria adopted for evaluating the derogation requests can evolve and change. **ERERA** and/or the relevant national **Governing Institutions** with regulatory duties shall monitor such changes, to avoid discriminatory effects.

GC 9.2.4.4 The review and amendment of the criteria for granting derogations shall not affect the derogations already granted which shall continue to apply until the scheduled expiration date (as specified in any derogation decision).

GC 9.2.4.5 The following set of criteria shall be used to evaluate the requested derogation:

- a) Level of risks associated with the non-compliance for the **Facility**, the relevant **Power System** and for the other relevant **Entities** or connected customers;
- b) Additional measures that could be taken to further mitigate the impact of the non-compliance on the **Power System** and/or other relevant **Entities** or connected customers for the duration of the non-compliance;
- c) Outstanding objections from other **Entities** who are materially affected by the non-compliance;
- d) Competitive advantages arising from the derogation to the **Entity** seeking a derogation;
- e) Adverse effects on cross-border electricity exchanges;
- f) Any other criteria, reasonable to the grantor to address the non-compliance, that have not been considered above.

GC 9.2.4.6 Where an applicant is unable to satisfy all the criteria in article GC 9.2.4.5, the grantor shall assess how far the applicant's ability to satisfy the criteria is enough to justify the granting or rejection of a derogation.

GC 9.2.5 ***Derogation Decision***

GC 9.2.5.1 Where the grantor considers that the derogation request is sufficiently justified, then it shall issue a deliberation to the affected applicant granting the necessary relief from the relevant obligation, for a time period specified in the deliberation.

GC 9.2.5.2 The grantor shall reject the request for derogation for lack of **Information**, procedural flaws or insufficient justification.

GC 9.2.5.3 The grantor shall revoke a derogation if the circumstances and underlying reasons for the derogation no longer apply.

GC 9.2.5.4 In case of refusal or revocation of a derogation, the applicant or the grantee shall present a realistic and comprehensive implementation plan that includes:

- a) The works required to meet compliance, where applicable.
- b) The timetable for those works that show a deadline that is reasonable and is achievable.
- c) Any measures, to mitigate the risks to other **Entities**, that will be (or have been) taken until the non-compliance is restored.

GC 9.2.5.5 The applicant or grantee shall notify to the grantor and to **ERERA**, any event that makes the application or deliberation invalid, including the effects of its actions able to solve the reasons of the non-compliance, within three (3) days from the occurrence of the event.

GC 9.2.6 ***Register of Derogations***

GC 9.2.6.1 The grantor shall keep a complete register of all derogations that are under evaluation, granted, rejected, and expired. The register shall contain:

- a) Request for derogation
- b) The technical requirements for which the derogation was granted or refused.
- c) The reasons for granting or refusing the derogation.
- d) The content of the deliberation.
- e) The status of the deliberation
- f) The monitoring of the expiring of derogations.
- g) The consequences resulting from granting the derogations.

GC 9.2.7 ***Role of the Regulatory Institutions on Derogations***

- GC 9.2.7.1 The register of derogations shall be available at the request of the relevant regulator (**National Regulatory Authority** or **ERERA**, where applicable).
- GC 9.2.7.2 The relevant **Governing Institution** with regulatory duties (the **National Regulatory Authority** as far as Derogations A are concerned, and **ERERA** as far as the Derogations B are concerned) shall exercise the power of control on the transparency, the non-discrimination, the system costs and the amount of the exceptions.
- GC 9.2.7.3 The relevant **Governing Institution** with regulatory duties is empowered to open an enquiry and discussion on granted and/or non-granted derogation.

GC 9.3 **Grid Operator Provisions on Derogation A and B**

- GC 9.3.1 Each **Grid Operator** shall set a procedure that regulates the process of request, analysis and evaluation of a derogation in accordance with the provisions of GC 9.2 and the regulation of its jurisdiction.
- GC 9.3.2 The relevant **Grid Operator** shall define in the procedure, the detailed lists and formats of **Information** that a **Facility Owner** shall include within its request for derogation.
- GC 9.3.3 The **Information** to be provided by the **Facility Owner** shall primarily identify at least the provision which the **Facility Owner** is, or will be, unable to comply with, the technical reason(s) for the non-compliance requiring derogation, and the expected effect on the **Relevant Grid** and cross-border electricity exchanges.
- GC 9.3.4 The procedure shall identify:
 - a) the process to be followed by the **Grid Operator** in evaluating the derogation requests and issuance of the deliberation;
 - b) the timings of the process; and,
 - c) the conditions under which a decision granting a derogation may be revoked.

GC 9.3.5 The relevant **Grid Operator** shall:

- a) keep a register of all derogations which have been granted, without prejudice to the confidentiality.
- b) on request from a **Facility Owner**, provide a copy of the register limited to the **Facility Owner's** own derogation request.

GC 9.4 Norms applicable to Grid Operator Temporary Non-compliances

GC 9.4.1 *Scope of Grid Operator Temporary Non-compliances*

GC 9.4.1.1 **Grid Operator Temporary Non-compliances** are restricted to operational practices and policies which the **Grid Operators** are responsible for. Non-compliances are the **Grid Operators'** practices considered not to conform to the requirements of the **REM Codes**, or to the practices that are agreed within the **WAPP** in line with the **REM Codes**.

GC 9.4.2 *Rationale of Grid Operator Temporary Non-compliances*

GC 9.4.2.1 The decision on the **Grid Operator Temporary Non-compliances** shall involve the **Grid Operators** of the interconnected **Member States**. For the principle of solidarity and for the purpose of reinforcing the cooperation about the interconnected operation, as far as a **Grid Operator Temporary Non-compliance** is ascertained, it is considered convenient as far as viable to accept viable **Grid Operator Temporary Non-compliance** instead to exclude a country from the interconnection.

GC 9.4.3 *Transitional Provisions Framework*

GC 9.4.3.1 A **Grid Operator Temporary Non-compliance** shall be accepted only temporarily in the **Transitional Provisions Framework**.

GC 9.4.3.2 The acceptance of a **Grid Operator Temporary Non-compliance** is subject to the following conditions:

- a) The acceptable increase of risk of **Functional Operation**;
- b) The acceptable degradation of the quality of supply;
- c) The possibility to practice alternative remedial solutions available in the interconnected **Power System**;
- d) The execution of an **Inter-Grid Operators Agreement** as per ANNEX B –INTER-GRID OPERATOR AGREEMENT OUTLINE, which includes:
 - i. The declaration of all the **Grid Operator Temporary Non-compliances** through an **Addendum to the Inter-Grid Operators Agreement**;
 - ii. A time schedule to solve the **Grid Operator Temporary Non-compliances**;
 - iii. The acceptance of the **Compliance Continuous Monitoring** led by **WAPP**.

GC 9.4.4 ***Addenda to the Inter-Grid Operators Agreement***

GC 9.4.4.1 **Grid Operator Temporary Non-compliances** are declared upon the execution of the **Inter-Grid Operator Agreement** without prejudice to article GC 9.2.2.2. Each **Grid Operator Temporary Non-compliance** corresponds to one **Addendum to the Inter-Grid Operators Agreement** as per the contents outlined in ANNEX C – CONTENTS OF THE ADDENDUM. Each **Addendum to the Inter-Grid Operators Agreement** describes a **Grid Operator Temporary Non-compliance**, its limit, the time and modalities to solve it.

GC 9.4.4.2 A **Grid Operator** cannot be considered liable for the **Grid Operator Temporary Non-compliance** as long as the related **Addendum to the Inter-Grid Operators Agreement** is valid.

GC 9.4.5 ***Compliance Continuous Monitoring***

GC 9.4.5.1 **WAPP** shall establish a **Compliance Evaluation Group** as per the scheme outlined in ANNEX D – COMPLIANCE CONTINUOUS MONITORING.

GC 9.4.5.2 The **Compliance Evaluation Group** is established to:

- a) evaluate the acceptance of the **Grid Operator Temporary Non-compliance**;
- b) Keep a register of the **Addenda to the Inter-Grid Operators Agreement**;
- c) check the deadlines of the solutions and their implementations;
- d) organize the **Compliance Continuous Monitoring** process to check the status of the compliance among the **Grid Operators** of the **WAPPITS**.

GC 9.4.5.3 Each **Grid Operator** has the right to be part of the **Compliance Evaluation Group**, votes on, and accepts the decisions of the **Compliance Evaluation Group** within the limits of its Terms of Reference when signing the **Inter-Grid Operators Agreement**.

GC 10. DISPUTE RESOLUTION

GC 10.1.1 Disputes that arise in relation to **the REM Codes** among **Parties** will be handled according to the following steps.

- a) Negotiation among the disputing **Parties** as follows:
 - i. Where there is a **Dispute**, the aggrieved **Party** shall send a **Notice of Dispute** to the other **Party** (such aggrieved **Party** or **Parties** and defendant **Parties** or **Parties** form together the **Parties in Dispute**) and to **ERERA** by certified mail.
 - ii. The **Parties in Dispute** shall each appoint a senior representative with authority to resolve the matter ensuring that the senior representatives meet in good faith to resolve the **Dispute**.
- b) Where, within a period of 30 **Days** (or the period agreed by the **Parties**) no agreement has been reached, any of the **Parties in Dispute** may:

- i. Initiate the procedure for **Dispute** resolution established by **WAPP** by filing the corresponding **Notice of Dispute** according to the procedure's provisions;
- ii. If, after applying the **WAPP** procedure for **Dispute** resolution, an agreement between the **Parties** has not been reached, file a **Notice of Dispute** to **ERERA** and initiate the procedure for **Dispute** resolution established by **ERERA**.
- iii. File a **Notice of Dispute** directly to **ERERA** and initiate the **Dispute** resolution procedure established by **ERERA**.

GC 10.1.2 **ERERA** shall maintain a record of all **Dispute** resolution proceedings conducted under GC 10. **ERERA** shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such records which constitute confidential **Information**. For this purpose, such **Information** may be scaled and marked as “CONFIDENTIAL” or otherwise labelled as being confidential.

GC 10.1.3 Notwithstanding the confidential matters, **ERERA** shall arrange for publication on **ERERA**’s website of the following:

- a) The **Parties in Dispute**;
- b) Notice of the appointment of the professionals in charge of the resolution of the **Dispute**;
- c) Notice of the date, time and place fixed for hearings, if any; and
- d) A summary of the award.

GC 11. INTERPRETATION OF THE REM CODES

GC 11.1.1 Where any **Facility Owner**, **Grid Operator** and other relevant **Parties** require interpretation of the wording or the application of any provision of the **REM Codes**, they may formally request to **ERERA** for such interpretation. Provided that the request is reasonable, **ERERA** has the faculty to provide the applicant with an interpretation of the relevant provision of the **REM Codes**. **ERERA** also has the faculty to carry out any investigation on the matter. In case of answer, this is without prejudice that the interpretation:

- a) Is Published as interpretation bulletin in accordance with GC 4.5;
- b) Is binding;
- c) Will be subject to the amendment provisions of GC 4.

GC 11.1.2 Where **ERERA** decides not to provide the interpretation requested, the modification process of the **REM Codes** as per GC 4 may be taken into consideration for clarifying the matter.

GC 12. HIERARCHY OF GOVERNANCE DOCUMENTS

GC 12.1.1 The provisions of the **REM Codes** shall replace all or part of relevant **ERERA** regulations and **WAPP** technical rules on the same matters in force before the approval of the **REM Codes**, and it will become constituent part of the **REMR**. In the event of any conflict between the provisions of the **REM Codes** and any provision of **National Grid Codes** or any other national rules, contract, bilateral agreement, the **REM Codes**, shall prevail.

GC 12.1.2 The **Operational Procedures** shall be aligned with the provisions of the **REM Codes**.

GC 13. CONFIDENTIALITY

GC 13.1.1 All data and **Information** exchanged relating to the **REM Codes** shall be handled by all **Facility Owners, Grid Operators** or other relevant **Parties** according to the confidentiality rules.

GC 13.1.2 **Confidential Data** do not include:

- a) **Information** that is in the public domain provided that the **Information** is not in the public domain as a result of a breach of confidentiality by the **Parties** mentioned in article GC 13.1.1.
- b) **Information** required to be Published or **Information** required to be disclosed in the **REM Codes**.
- c) **Information** that must be disclosed in compliance with a judicial or governmental order or other legal process.

GC 13.1.3 **ERERA** shall consult with the **Facility Owners**, the **Grid Operators** and other relevant **Parties** regarding the publication of any of the data exchanged. Aggregate data may be made available by the **Facility Owners**, the **Grid Operators** and other relevant **Parties** when requested by any other **Facility Owner, Grid Operator, Market Participant**, and the **SMO**, or other relevant **Party**. This data shall be used only for the purpose specified in the request and shall be treated by the **Facility Owners**, the **Grid Operators** and other relevant **Parties** as confidential. All such disclosure of **Confidential Information** shall be subject to a written **Confidentiality Agreement** duly signed between involved **Facility Owners, Grid Operators** or other relevant **Parties**. Such confidential Information shall not be disclosed to other **Parties** without the express written consent of the **Parties** to the **Confidentiality Agreement**.

ANNEX A – INSTITUTIONAL STRUCTURE

A.1 Scope

A.1.1 This ANNEX A – INSTITUTIONAL STRUCTURE describes, for the sole purpose of the **REM Codes**, the institutional structure created to regulate and operate the **REM** and identifies the different classes of **Market Participants** and their rights and obligations under the **Market Participant Agreement** and the **REM Codes**. This ANNEX A – INSTITUTIONAL STRUCTURE shall be kept up-to-date and aligned with the existing and valid institutional structure of the **REM**. In case of inconsistency, a revision of this part of the **REM Codes** should be performed.

A.1.2 The institutional structure is governed by the **REMR**. Therefore, the scope of this INSTITUTIONAL STRUCTURE is only for referencing purposes, and any change in the **REMR** on this matter shall prevail on the contents of this ANNEX A – INSTITUTIONAL STRUCTURE.

A.2 Description of Governing Institutions

A.2.1 The **Governing Institutions** of the **REM**, as specified in the **REMR**, comprise the following:

A.2.1.1 At Regional level:

- a) The **ECOWAS** Council of Ministers;
- b) **ERERA** acting as the regional regulator and maintaining the consultation framework of the **National Regulatory Authorities (NRA)**;
- c) The **WAPP** acting as coordinator of **Grid Operators** in technical matters;
- d) The **SMO** acting as the **System and Market Operator** of the **REM**.

A.2.1.2 At National level of **Governing Institutions**:

- a) The **Governing Institutions** of the **Member States**;
- b) The **National Regulatory Authorities (NRAs)**;
- c) The **Grid Operators**.

A.2.2 The **ECOWAS** Council of ministers has a supervisory role on the governance of the **Regional Electricity Market**. For this purpose, it approves the institutional and framework regulations of the **REM**, the budget of **ERERA** and receives the report of **ERERA** on the **REM**.

A.2.3 **ERERA** regulates cross-border electricity exchange in the **REM**, while ensuring the implementation of conditions to guarantee its optimization, reliability and contribution to the establishment of a regulatory and economic environment favourable to the establishment of the **Regional Electricity Market**.

A.2.4 **WAPP** is responsible for the development of energy production **Facilities**, the interconnection of electricity **Grids**, the realization of regional investments and the development of the **REM** in collaboration with **ERERA**.

A.2.5 The **SMO** is responsible for the operation of the **REM** and the coordination of the **Functional Operation** of the **WAPPITS** in collaboration with the **Grid Operators**.

A.2.6 The **National Regulatory Authorities (NRAs)** and other **Governing Institutions** of the **Member States** ensure the implementation of the **REMR** at the national level and support the regional **Governing Institutions** in the administration, management, and development of the **REM**.

A.2.7 The **Grid Operators** are responsible for the day-to-day operation of the **Power Systems** of **Member States** and collaborate with the **SMO** for the **Functional Operation** of the **WAPPITS**.

A.3 REM Regulation

A.3.1 **ERERA** is the regulatory **Entity** for the **REM**. Without prejudice to Regulation C/REG.27/2/07 and its further updates, as legally approved, on the composition, organization, functions and operation of **ERERA**, the roles and responsibilities of **ERERA** include but not limited to:

- a) Ensure compliance with the rules and legal framework of the **REM** and the **REM Codes**;
- b) Ensure that **REM Participant** behaviour and the functioning of the **REM** is consistent with the **REM Codes**;
- c) Determine fees and tariffs for regulated activities in the **REM** including coordination of each **Member State**'s other applicable transmission services charge to be applied to transactions in the **REM**;
- d) Ensure transmission services charges are applied to transactions in the **REM** in a fair and non-discriminatory manner;
- e) Review and advise on proposed changes to the **Market Participant Agreement**;
- f) Review and approve proposed changes to the **REM Codes**;
- g) Review and give its opinion on proposals for expansion of the **Relevant Grid** of the **WAPPITS** in accordance with the **Master Plan**;
- h) Review and approve **Reserve** criteria;
- i) Review and advise on rules governing allocation of **Cross-border Interconnection** capacity;
- j) Review and approve the methodology for calculation of **TTC / NTC / ATC**;
- k) Review and advise on credit obligations and payment default procedures;

- l) Mediate disputes between and among **Market Participants** and the **Governing Institutions**;
- m) Coordinate with the national regulators;
- n) Participate in the development of energy policies;
- o) Conduct research and development activities relating to regulation of the **REM**; and
- p) Facilitate the development of the **REM**.

A.3.2 In its capacity to ensure compliance with the **REMR** and the **REM Codes** and promote development of the **REM**, **ERERA** is authorized to request audited accounting Information of **Market Participants** and the **Governing Institutions**.

A.3.3 In fulfilment of its objectives and obligations, **ERERA** is responsible for:

- a) Regulating the application of penalties in cases of non-compliance or breach of the **REM Codes**;
- b) Reviewing and approving the **Facilities** that make up the **WAPPITS**;
- c) Reviewing and recommending proposals for construction of new **Cross-border Interconnection Facilities**;
- d) Reviewing and adopting accounting principles for **Entities** participating in the **REM**;
- e) Reviewing and approving budgets, fees and charges for the **SMO**;
- f) Reviewing and approving transmission service charges for application to transactions in the **REM**;
- g) Empowering the market surveillance committee investigate and analyse situations of potential **Market Power** abuse;
- h) Preparing periodic regulatory reports evaluating the status of **REM** development in meeting its objectives; and
- i) Approving changes to the **REM Codes**.

A.4 REM Operation

A.4.1 The **SMO** is the system-market operator of the **REM**. The **SMO** is responsible for the efficient operation of the **REM** in accordance with the **REMR** and the **REM Codes**.

A.4.2 The **SMO** is the independent **Entity** that is legally authorized to carry out all acts, contracts and other actions required to direct operation of the **REM**.

A.4.3 The **SMO**, in conjunction with the **Grid Operators**, is responsible for electricity scheduling, billing and **Settlement** in the **REM** based on the principles of fairness, efficiency, safety and transparency. The **SMO** is responsible for:

- a) Submitting procedures for **REM** operation to **WAPP** for review and to **ERERA** for approval.
- b) Conducting **REM** operation and scheduling in conjunction with the **Grid Operators** using economic criteria, seeking to maintain satisfactory levels of security, quality and reliability.
- c) Reviewing and verifying in conjunction with **Grid Operators** the technical feasibility of **Bilateral Contract** transactions.
- d) Managing commercial transactions in the **REM**.
- e) Developing a revision of the auction process for **Cross-Border Interconnection** capacity, for review by the **WAPP** and subsequent approval by **ERERA**.
- f) Administering the approved auction process for **Cross-Border Interconnection** capacity.
- g) Coordinating **REM** operation with the **Grid Operators**.
- h) Developing and publishing indicative market prices without prejudice of confidentiality rules.
- i) Developing and publishing model **Bilateral Contracts** for services that can be purchased and sold in the **REM**.
- j) Providing **Market Participants** access to the market database and methodologies used by the **SMO**.
- k) Providing public access to non-confidential **Information** in the market database.

A.5 System Operation Coordination

A.5.1 In the framework of system operation coordination, the **SMO** shall organise:

- a) the coordination of power flows.
- b) the transfer capacity calculations.
- c) the allocation of transmission capacity.
- d) the cooperation with **Grid Operators**.

A.6 WAPP

A.6.1 The **West African Power Pool (WAPP)** refers to both **WAPP** as interconnected **Power System** of West Africa and **WAPP** as an organisation.

A.6.2 The **WAPP** as a system is established by Decision A/DEC.5/12/99 of December 10, 1999, of the Authority of Heads of State and Governments, to provide an appropriate framework for development

of energy production **Facilities**, the interconnection of electricity **Grids**, the realization of regional investments and the development of energy exchange in West Africa.

A.6.3 The **WAPP** organization is the specialized institution of **ECOWAS** established by Decision A/DEC.20/01/06 of January 12, 2006, by the Authority of Heads of State and Governments, for the realization of the **WAPP** system and whose management structure is instituted by the Articles of Agreement of July 6, 2006 as amended.

A.6.4 In the **REM Codes**, **WAPP** as organisation is specified when the text refers to a function that pertains to or a decision to be taken by the **WAPP** Organization at any level of its governance structures, including but not limited to:

- a) Support the coordination and cooperation among national **Grid Operators**.
- b) Organize, participate in and assess the **Compliance Continuous Monitoring** process.
- c) Promote the **Regional Electricity Market**, reliability and security of supply, efficiency, and technical innovation.
- d) Coordinate the drafting and the implementation of network development plans.
- e) Coordinate the support to the development and compliance of **National Grid Codes** to the **REM Codes**.
- f) Draft and adopt standards and procedures for the **REM** for final approval by **ERERA**.
- g) Prepare and submit to **ERERA** for assessing the capacity obligation and the reserve sharing guidelines based on minimum **Reserve** requirements to be carried by the **Grid Operators**.
- h) Assess and make recommendations to **ERERA** relating to the need for changes to the **REM Codes**.
- i) Review and implement changes to standards and other lower hierarchy documentation associated with the **REM Codes**.
- j) Conduct research and development activities relating to reliability and **Security of Supply** issues.
- k) Participate in the development of energy policies.

A.6.5 In the **REM Codes**, **WAPP** as a system is specified in all cases other than those specified in paragraph A.6.4.

ANNEX B – INTER-GRID OPERATOR AGREEMENT OUTLINE

B.1 Scope of the agreement

B.1.1 The **Inter-Grid Operator Agreement** is drafted by **WAPP** and signed by all **Grid Operators**, with **WAPP** as the organizer of the process and coordinator of the agreed actions.

B.1.2 The agreement shall correspond to the following pattern:

- a) The declaration of compliance with rules and technical requirements prescribed by the **REM Codes**.
- b) The declaration of the list of non-compliances in the form of **Addenda to the Inter-Grid Operators Agreement**.
- c) The acceptance of the terms of reference of the **Compliance Continuous Monitoring** process run by **WAPP** and in particular to perform and be subject to the considered auditing procedures.
- d) The regulation to handle the claims for damages suffered by one or more **Grid Operators** caused by incidents and infringements of interconnection rules.

B.1.3 The **Inter-Grid Operator Agreement** shall include at least the following contents:

- a) Clear identification of the signing **Grid Operators**.
- b) the acknowledgment of the role of coordination played by **WAPP**;
- c) the acknowledgment of the principles of solidarity guiding the actions of Interconnected **Member States**;
- d) the awareness that **Grid Operators** are legally subject to the relevant national laws;
- e) the awareness that the interconnected operation implies risks of propagation of disturbances;
- f) the knowledge of the **REM Codes**;
- g) the acceptance of the **REM Codes**.

B.2 The procedures, in case of incidence of damage to other Grid Operators or their associated parties

B.2.1 **Parties** to the **Inter-Grid Operator Agreement** shall be aware and accept the following responsibilities in case of incident:

- a) The applicable procedure to be triggered by the damaged **Parties**, including deadlines for replies and amicable solutions.
- b) The description of claims and the request of compensation.

- c) The terms for amicable solutions.
- d) The establishment by **WAPP** of a technical independent pool of experts to analyse the events from the technical point of view and express technical opinion.
- e) The establishment by **WAPP** of a legal and technical group of experts to verify and quantify the claimed damages.
- f) The terms for the discussions within **WAPP**.
- g) The decision-making majority in voting procedures.

B.2.2 Moreover, it shall be specified:

- a) The applicable law in case of failure of conclusion and continuation according to the ordinary law.
- b) The language to be adopted in the proceeding documents.

B.3 Additional elements for new Grid Operators

B.3.1 Applicants shall add to the **Inter-Grid Operator Agreement**:

- a) The formal request to be part of the interconnection.
- b) The results of compliance tests performed to prove the interoperability of their **Power System** with the **WAPP Power System** and the compliance with the **REM Codes** and/or **WAPP** practices;
- c) The previous preliminary agreements signed with **WAPP**;
- d) The name of the **Grid Operator**, and the name and description of the **Grid**;
- e) The control infrastructures;
- f) The availability to exchange operational data and **Information**.

ANNEX C – CONTENTS OF THE ADDENDUM TO THE INTER-GRID OPERATORS AGREEMENT

C.1 Definition

C.1.1 The **Addendum to the Inter-Grid Operators Agreement** is an approved document where a **Grid Operator** self declares the non-compliance with a specific prescription of the **REM Codes**. The matters in question focus on operation practices and policies whose responsibility lies on **Grid Operators**.

C.1.2 The **Addendum to the Inter-Grid Operators Agreement** is an additional element related to the provision of the Code it refers to, applicable to the **Grid Operator** who issues the **Addendum to the Inter-Grid Operators Agreement**. The **Grid Operator** raising such **Addendum to the Inter-Grid Operators Agreement** cannot be liable for the declared non-compliance.

C.1.3 The **Grid Operator** raising an **Addendum to the Inter-Grid Operators Agreement** makes the commitments to remove the barrier that impede the full compliance and solve the issue in the way and the time it declared itself.

C.2 Information required

C.2.1 The following minimum set of **Information** are required:

- a) **Grid Operator** identification.
- b) Provisions which are the object of the **Grid Operator Temporary Non-compliance**.
- c) Reason/s for the **Grid Operator Temporary Non-compliance**.
- d) Current actions to mitigate the **Grid Operator Temporary Non-compliance**.
- e) Roadmap of actions and expected dates for resolving the **Grid Operator Temporary Non-compliance**.
- f) The strategies to upgrade technical tools (e.g. **SCADA**) and organizational provisions (e.g. resources for real time control) to resolve the **Grid Operator Temporary Non-compliance**.

C.2.2 The **WAPP** can complement the previous requests with further details, if the nature of the **Grid Operator Temporary Non-compliance** requires it.

ANNEX D – COMPLIANCE CONTINUOUS MONITORING

D.1 Aims and Scope

- D.1.1 The **Compliance Continuous Monitoring** aims at promoting the continuous enhancements of security of operation and cooperation among **Grid Operators** for the benefit of the interconnection and the development of the **REM**.
- D.1.2 The specific scope of the **Compliance Continuous Monitoring** contributing to the **Security of Operation** throughout the control of the compliance with the **REM Codes** and the agreed practices.
- D.1.3 The **Compliance Continuous Monitoring** is implemented by the activities of the **Compliance Evaluation Group**.

D.2 Organization

- D.2.1 The **Compliance Evaluation Group** is a group led and organized by the **WAPP**. Its resources are provided by the **Grid Operators** that are encouraged to actively take part of the group.
- D.2.2 **WAPP** has the faculty to decide where to locate **Compliance Evaluation Group**.
- D.2.3 **Grid Operators** are requested to contribute with expertise in the topics to be assessed from time to time.

D.3 Activity

- D.3.1 The **Compliance Evaluation Group** is in charge of monitoring the **Addenda to the Inter-Grid Operators Agreement** within the framework of the **Inter-Grid Operators Agreement**. In this context, it is in charge of drafting statistics and reporting it to **WAPP** highlighting the criticalities.
- D.3.2 The **Compliance Evaluation Group** shall update the terms of reference of its activities at most every three (3) years.
- D.3.3 The chairperson shall be elected every three (3) years.
- D.3.4 According to the activity time schedule of **WAPP**, each year the **Compliance Evaluation Group** is required to propose a rolling working program for the next three (3) years. This program shall at least:
 - a) Propose a self-assessment campaign, where the **Grid Operators** declare under their responsibilities, the status of the compliance against a given topic list, in a scale from 0% compliance to 100% compliance.

- b) Propose, organize and agree on a list of auditing missions on specific topics or to check the status of the resolution or the mitigation of the **Grid Operator Temporary Non-compliance** as per the **Addenda to the Inter-Grid Operators Agreement**.
- c) Propose audits focussed on the progress scheduled in the **Addenda to the Inter-Grid Operators Agreement** or verification of the results of the self-assessment campaign.

D.3.5 The **Compliance Evaluation Group** is required to support enquiry committees, on demand, to ascertain the impact of **Grid Operator Temporary Non-compliance** in case of major incidents in the **WAPP Power System**.

D.4 Main Tasks

D.4.1 Unless the **WAPP** decides otherwise, the objectives of the **Compliance Evaluation Group** are considered achievable by performing the following tasks:

- a) Design and implement actions to execute **Compliance Continuous Monitoring**.
- b) **Publishing** the Information on the status of compliance within **WAPP** and **Member States**, and without prejudice to the confidentiality of Information.
- c) Regularly updating a monitoring and control status including:
 - i. the choice of the topics to be self-assessed yearly;
 - ii. the choice of the topics to be assessed in on-site audits;
 - iii. the set-up of questionnaires to make the interpretations of the questions in the self-assessment unambiguous;
 - iv. preparing the compliance report to be presented to **WAPP** for further improving initiatives, including:
 - the recommendations to **WAPP** for measures in case of non-compliance;
 - the proposals for reviewing the technical provisions of the **REM Codes**;
 - the adoption of key-performance indicators to ensure that performances are fairly measurable.
- d) Pooling resources for regular and exceptional on-site audits;
- e) Actively supporting **Grid Operators** to reach full compliance.

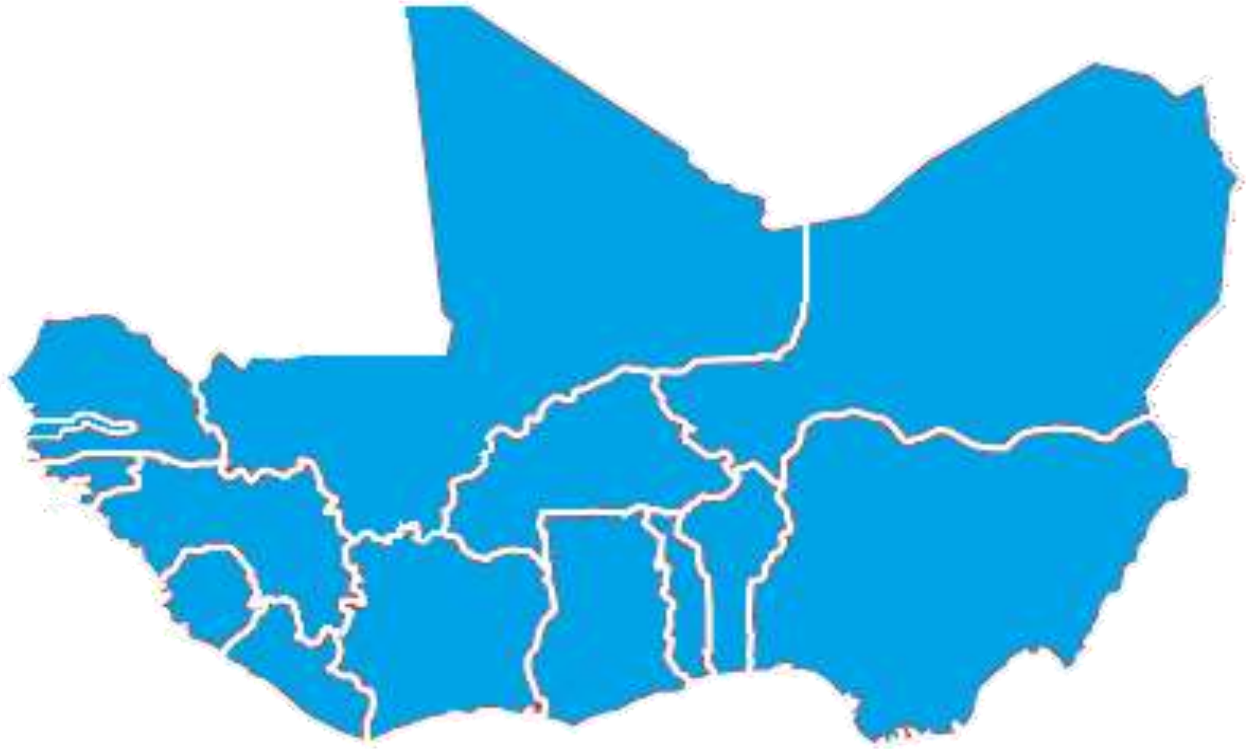
D.5 Methodology

D.5.1 The **Compliance Continuous Monitoring** shall be based on the best auditing practices, and it is self-managed by operation expertise.

D.5.2 The **Compliance Evaluation Group** shall work in full transparency, adopting the best technique in matter of auditing. In particular all documents have to be approved and sent in advance to the **Grid Operator** to be audited.

- D.5.3 The decisions on which topic has to be audited and which **Grid Operators**, have to be agreed among the **Compliance Evaluation Group** and approved by **WAPP**
- D.5.4 Confidentiality has to be always guaranteed in the framework of the **Compliance Evaluation Group**'s activities.
- D.5.5 The auditing teams should be composed of expertise on the topic to be assessed made available by non-neighbouring **Grid Operators**.

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



PC – PLANNING CODE

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PC 1. OBJECT AND SCOPE OF THE PLANNING PROCESS

PC 1.1 Object and Scope

PC 1.1.1 The **Planning Code** provides rules and guidelines to ensure the effective and coordinated **Development Planning** of the **Cross-border Interconnections** of the **Region**. The **Development Planning** of the **Relevant Grid** refers to planning the resources of the interconnected **WAPP Power System** that will be made available for **Functional Operation** within the time frame established in this **Planning Code**. Hence this **Planning Code** calls for a strict commonality of criteria across **Member States**.

PC 1.1.2 The **Planning Code** is to facilitate (i) the expansion of the **Cross-border Interconnections** and (ii) the reinforcement of the **Relevant Grids** for the optimal use of the interconnections themselves. The scope of this **Planning Code** include:

- a) **Development Planning** for short-term, medium-term and long-term, and their implementation (PC 2, PC 5 and PC 6);
- b) design of a central data infrastructure to guarantee efficient data exchange, data adequacy and their interoperability (PC 3);
- c) guidelines and methodology for **Development Planning** (PC 4);
- d) guidelines for long-term generation adequacy forecast (PC 7); and
- e) formal obligations of relevant parties with respect to handling of sensitive information (PC 8).

PC 1.1.3 While the development of electricity generation assets is considered in the planning process, and its **Adequacy** assessed, they are out of the scope of this **Planning Code**. National energy policies are under the full responsibility and autonomy of the **Member States**

PC 1.1.4 The initiatives which are proposed in common and aiming at solving stability issues, increasing **Flexibility** for facilitating the integration of the **Renewable Energy Resources (RES)**, and reinforcing the control infrastructures (e.g. Telecommunications, **SCADA**, Substation Automation) are considered as relevant development of the interconnection and shall be included in the planning activities.

PC 1.2 Principles of the Planning Process

PC 1.2.1 The **Development Planning** process is cyclical and organized in three (3) different time-frameworks:

- a) The **Long-Term Vision Planning**, which is dedicated to set up long-term strategies and to define **Long-Term Targets (LTTs)** in line with the Economic Community of West African States (ECOWAS) policies and more general future trends.

- b) The **Intermediate Planning**, which delivers a medium-term roadmap covering a time horizon of ten (10) to fifteen (15) years to periodically check and provide the information for aligning the **Priority Plan** to the **LTTs**.
- c) The **Priority Plan Development**, which delivers a list of priority **Regional** transmission projects (i.e. the **Priority Plan**) covering the next 10-years horizon, based on the **Intermediate Planning** and **Long-Term Vision Planning**.

PC 1.2.2 **WAPP** shall present to ECOWAS the outcome of each step as a single document called “**Master Plan**”, which may cover **Regional** transmission projects that may go beyond the priority ones to be approved in the **Priority Plan**.

PC 1.2.3 A graphical representation of the three (3) different timeframes indicated in article PC 1.2.1, as further detailed in PC 2, PC 5, and PC 6 is presented in *DEVELOPMENT PLANNING TIMEFRAMES*.

PC 1.3 Key Goals

PC 1.3.1 The key goals of the planning of **Cross-border Interconnections** are to:

- a) increase the reliability and security of the **Power Systems** of the **Member States** and of the **Cross-border Interconnections**;
- b) enable efficient operation of the **Regional Electricity Market (REM)**;
- c) design an environmentally sustainable **WAPP Power System**;
- d) contribute to the stability of the investments on infrastructures;
- e) improve the access and affordability of the electricity for the citizens of the **Member States**;
- f) accommodate and integrate **Renewable Energy Sources (RES)**.

To achieve these, **Grid Operators** shall give high priority to the harmonization of the **Development Plans**.

PC 1.4 Compliance Goals

PC 1.4.1 **Grid Operators** shall harmonize the national **Development Planning** methodologies with the respective **National Grid Codes**. The **Grid Operators**, in this process of harmonization shall:

- a) apply the same criteria prescribed in the **Operation Code** in terms of N-1 security criteria, **Contingency** definition and analysis, voltage and current limits.
- b) take into consideration the main drivers of development in their respective countries and the conditions of the respective **Power Systems**.

- PC 1.4.2 The goal of the harmonized development plan shall comprise that of the **Development Plans** which would gradually incorporate the more general objectives of the **Priority Plan** of the **Cross-border Interconnections** for the benefit of the whole **WAPP Power System**.
- PC 1.4.3 This **Planning Code** aims at interfacing the **National Grid Codes** on planning and harmonizing the process of development of the **Cross-border Interconnections**. The **WAPP** shall be responsible for ensuring a continuous harmonization process between national planning and regional planning.
- PC 1.4.4 In order to give continuity to the process, the **Grid Operators** shall set up **Development Plans** that take into account the last approved **Priority Plan** and propose new or updated cross-border projects as input into the new **Priority Plan** being developed. This cyclic iteration between the **Development Plan** and **Priority Plan** shall be biannual.
- PC 1.4.5 At the date of the entry into force of this **Planning Code**, **Grid Operators** shall use, as a first referenced **Priority Plan**, the latest **Master Plan** approved by **ECOWAS**, that is the document ECOWAS MASTER PLAN FOR THE DEVELOPMENT OF REGIONAL POWER GENERATION AND TRANSMISSION INFRASTRUCTURE 2019-2033 issued in December 2018.
- PC 1.4.6 In the cyclic process referred to in article PC 1.4.4, **WAPP** shall monitor, audit the entire process, and provide relevant inputs into the **Master Plan**. It shall also keep track of the status of the interconnection projects specifying if already planned, if in progress, if concluded and in operation, if delayed, and / or cancelled.
- PC 1.4.7 **WAPP** shall **publish** annually a report on the status of the actual and planned development of the interconnected **WAPP Power System**, duly detailed, also for the further actions towards **ECOWAS**.

PC 1.5 The Priority Plan Outline

- PC 1.5.1 The drivers of the **Priority Plan** are the initiatives of the **Member States** in respect of **Cross-border Interconnection**.
- PC 1.5.2 Drivers originating from **WAPP** or higher levels (i.e., **Governing Institutions** at national and **Regional** level such as governments, **ECOWAS**, **ERERA**) should be taken into account with the highest priority.
- PC 1.5.3 The strategies and targets derived from the strategic vision of the **Long-Term Vision Planning** as elaborated in the **Intermediate Plans** shall be considered as priority drivers.
- PC 1.5.4 The initiatives are expressed in interconnection projects. Such projects can be proposed, changed or cancelled by the **Member States** at each iteration of the **Priority Plan** if not initiated or funded.

- PC 1.5.5 Without prejudice to the priority placed on primary infrastructures (e.g., lines, substations), the following projects shall also be considered:
- a) Projects for improving the control and protection of the **Cross-border Interconnection** and to increase the power exchanges. Such projects shall be supported to reach the targets of compliance with the **Operation Code** timeously.
 - b) Projects for the improvement of the **Flexibility** of the **Grid**.
- PC 1.5.6 The **Priority Plan** is the **Development Planning** document covering the shortest time period, and it shall consist of:
- a) The synthesis of the **Development Plans** of the **Member States** with respect to the **Relevant Grid** over the time horizon of the **Priority Plan**.
 - b) The description of the transmission projects on **Cross-border Interconnections**, consisting of:
 - i. The **Cross-border Interconnections** between neighbouring **Grid Operators**.
 - ii. The expected increase of **NTC** between the interconnected areas associated with each transmission project.
 - iii. The **Transmission System** reinforcements and/or the refurbishment needed to reach the targets and comply with the **Security of Operation (SoO)**.
 - iv. The cost benefit analysis and the **Key Performance Indicator (KPI)** values.
 - c) The recap of criteria and decisions adopted in the process.
 - d) Transmission projects aiming at increasing the **Regional** utilization of the infrastructures.
 - e) Projects to improve the **Flexibility** of the **Grid**.
- PC 1.5.7 The ranking of the transmission projects shall be based on the cost benefit analysis (as per PC 4.10) and on the parameters that better reflect the policies of the **Region**.
- PC 1.5.8 The **Priority Plan** shall serve as a development guide for the **Grid Operators** involved. Transmission projects may be modified and presented in the **Priority Plan** with modifications or different evaluation of the benefits due to changes in general conditions or eventually cancelled.
- PC 1.5.9 Seasonal reports or outlooks on **Adequacy**, considering the benefits from the energy transfers, are part of the **Operation Code**.

PC 2. THE PRIORITY PLAN DEVELOPMENT PROCESS IMPLEMENTATION

PC 2.1 Description of the Planning Process

- PC 2.1.1 The **Member States** shall take responsibility for the preparation of their own transmission project initiatives. These transmission project initiatives shall be forwarded to **WAPP** to initiate the planning process. **WAPP** shall perform adequacy and market studies in a centralized way at **Region** level without imposing solutions on the **Member States**.
- PC 2.1.2 The planning process starts with the preparation of the relevant transmission projects that each **Grid Operator** will include in its **Development Plan**. This activity is performed autonomously by each **Grid Operator** considering the conclusions and indications of the latest and current **Master Plan**. The part of the **Development Plans** relating to the **Relevant Grid** and **Cross-border Interconnections** between **Grid Operators** is subject to co-ordination as provided for in article PC 2.1.3.
- PC 2.1.3 The co-ordination of the transmission projects requires the collection of the initiatives, the analysis of the contents, the drafting activity of the **Development Plan** relating to the **Relevant Grid** and **Cross-border Interconnections**, consensus among **Grid Operators** and administrative issues. For this purpose, the **WAPP** shall establish the Working Group, **WG4-Planning Working Group**, tasked with issues relating to coordination of **Development Planning**.

PC 2.2 Contribution of Grid Operators to the planning Process

- PC 2.2.1 The **Grid Operators** shall contribute to the well-functioning of **WG4** with the appropriate resources. Accordingly, the **WG4**:
- a) may be permanent or temporary – according to the decision of **WAPP** – and shall report to the **WAPP**;
 - b) shall work according to term of reference, approved by **WAPP**;
 - c) in discharging its duties, may establish sub-groups and decide how to share the activities among such sub-groups;
 - d) can propose to hire external expertise for specific studies.
- PC 2.2.2 The **WG4** shall comprise representatives of **Grid Operators** and a secretary who shall be a staff of **WAPP**. **WG4** shall be chaired by an elected representative of one of the **Grid Operators** for a tenure of two (2) years renewable once. For the development of any edition of the **Priority Plan**, the work shall be organized and shared among sub- groups such as:
- a) **Expert Group** to carry out centralized market, network studies, and any other activity **WG4** will consider necessary at the level of the **WAPPITS**.
 - b) **Study Area Groups**, one per possible electrical area as defined in article PC 4.2.6.

PC 2.2.3 **Grid Operators** shall contribute to the activities of the **Expert Groups** with qualified personnel and guarantee the needed time to accomplish the assigned tasks.

PC 2.2.4 The **WG4** shall support the **Grid Operators** in the assessments and modelling of their **Power System**, if required. The **WG4** may suggest modifications to the transmission projects as well. The **Grid Operators** shall, however, remain responsible for the transmission projects. Each **Grid Operator** is free to accept or reject the suggested modifications made by the **WG4**.

PC 2.3 Timing for the Priority Plan Development

PC 2.3.1 The main purpose of the **Priority Plan Development** process is to deliver a **Priority Plan** valid from the year Y.

PC 2.3.2 The planning horizon of the **Priority Plan Development** shall be a maximum of ten (10) years with six (6)-years rolling frequency.

PC 2.3.3 Within this six (6)-years of rolling period, the activities for the planning process of the **Priority Plan Development** shall span two (2) years starting from 1st of January of the year Y-2 (Start Date of the planning process) and ending at the target date for publishing the **Priority Plan** on the 31st of December of the preceding year Y-1 (End Date of the planning process). **WAPP** has the faculty to anticipate the starting of the activity before the 1st of January of the year Y-2, in case the approval process requires more time than the one envisaged in step *k*), as per PC 2.3.14.

PC 2.3.4 During the two (2) years of planning activity, cooperation among the **Grid Operators** shall be required to harmonize the interconnection initiatives with the **Transmission Systems** expansion, generation and distribution plans, as well as define **Cross-border Interconnection** projects.

PC 2.3.5 The time schedule of the planning process comprises eleven (11) steps, described in sequence from (a) to (k). The **WG4** may shorten the schedule, if possible, by carrying out some of these steps simultaneously. The timeline shown in Figure PC 1 is designed for a biannual cycle.

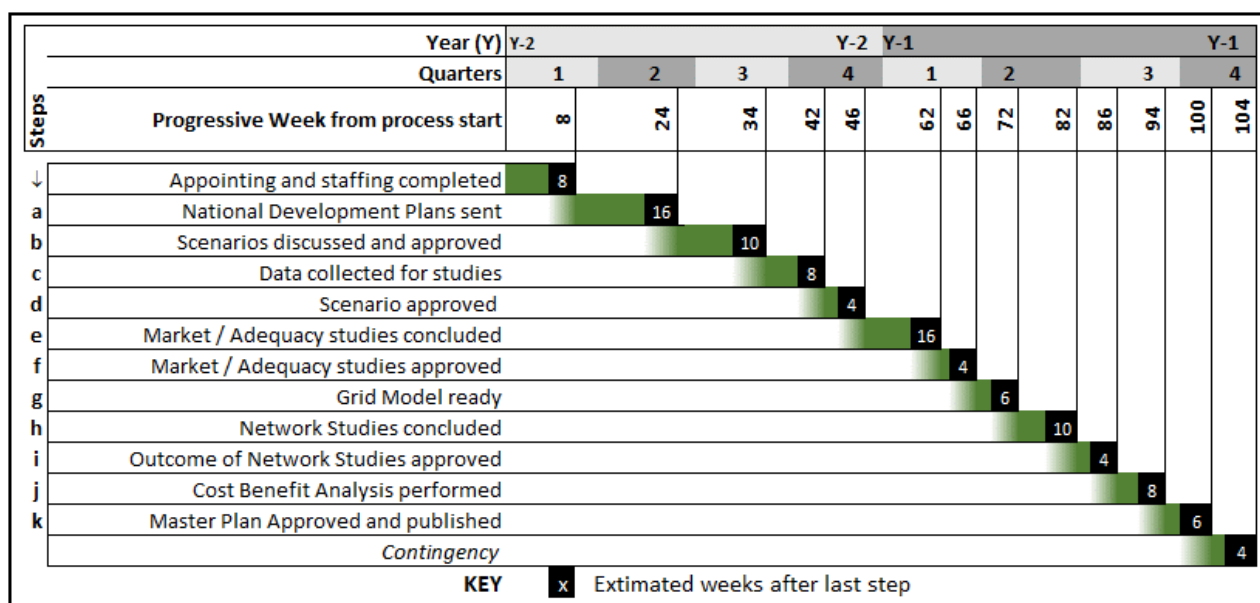


Figure PC 1. Timeline of the planning process.

PC 2.3.6 **Preliminary Phase**

- PC 2.3.6.1 As a first step, no later than the 8th week of the year Y-2, the **WAPP** shall set up the **WG4** with membership from **Grid Operators** and also setup the different **Expert Groups**, if necessary.
- PC 2.3.6.2 Each **Expert Group**, proposed by the **WG4** and approved by **WAPP**, may be supported by qualified external resources provided by **WAPP**.
- PC 2.3.6.3 The **WG4** shall agree on a detailed schedule in line with the requirements of PC 2.3 of this **Planning Code** and **WAPP** shall approve this binding detailed schedule, as soon as possible.

PC 2.3.7 **STEP a). Collection of the Development Plans Including the Interconnection Initiatives**

- PC 2.3.7.1 A maximum period of three (3) months shall be granted to **Grid Operators** to update their **Development Plans** and harmonize them with the priorities and targets of the **REM**.
- PC 2.3.7.2 By week a)¹ (24th week) (refer to Figure PC 1) each **Grid Operator** involved in the development of transmission projects shall forward to **WG4** its **Development Plans** for the planning horizon prescribed by their applicable national regulations.
- PC 2.3.7.3 If any **Grid Operator's Development Plan** is designed for a horizon shorter than the one agreed for the **Priority Plan**, then by week a) (24th week) (refer to Figure PC 1), that **Grid Operator** shall also forward parameters to enable **WG4** extrapolate the **Development Plan** till the final planning year as agreed in article PC 2.3.2.

¹ Hereinafter, the term *week* followed by the relevant *letter*) refers to the final progressive week at the end of the step identified with that *letter* in Figure PC 1.

- PC 2.3.7.4 The **Development Plans** shall at least highlight:
- a) the new **Cross-border Interconnections** projects, the reinforcements needed and the expected increases of energy transfer capabilities for each of them and their impact on the **Security of Operation, Security of Supply** and the **REM**.
 - b) the **Scenarios** and assumptions under which the transmission projects have been developed.
 - c) forecast data for the time horizon of the plan (**Demand** and **Generation**, detailing the kind of **Generation** resources).
 - d) main targets associated with the transmission projects and their contribution to the improvement of the performances of the **Transmission System** (e.g. losses reduction, quality of supply etc.).
- PC 2.3.7.5 The transmission projects shall be presented in a uniform editorial pattern, as established by **WAPP**, to speed up analysis and presentations, and minimise any risk of misinterpretation.
- PC 2.3.7.6 Projects may be single initiatives or clusters of transmission projects if aimed at the same objective and complement each other.
- PC 2.3.7.7 Preparations of the projects are considered finalized only when their techno-economic benefits have been determined and the costs of the cross-border transmission project plus the reinforcements have been assessed through cost-benefit analysis. Therefore, the **WG4** may recommend changes and **Grid Operators** may propose solutions during the process, to meet the recommendations received.
- PC 2.3.8 **STEP b). Definition of Scenarios and Drivers for the Interconnection**
- PC 2.3.8.1 On the basis of the **REM** targets and considering the peculiarities of the **Grid Operators**, the **WG4** shall:
- a) analyse the issues that drive the development of the **Grid** of each **Grid Operator**;
 - b) perform an analysis of the drivers in each **Member State**;
 - c) define the reference **Scenarios** for the study areas involved by the projects. **Grid Operators** within the **WG4**, shall decide the number of **Scenarios** to be developed;
 - d) recommend, at least, a minimum of two (2) initial **Scenarios**;
 - e) decide if the initial **Scenarios** can evolve into more than two (2), but not more than four (4);
 - f) classify transmission projects received from the **Grid Operators** according to their maturity (proposals, bilateral agreements, government requests), goal (economic benefits, **RES** integration, reliability, reduction of losses, **Adequacy**).

PC 2.3.8.2 The **WG4** shall propose the methodology for the **Scenario** analysis, draft the investment list and – after approval by **WAPP**, call for market and network studies at study area level by *week b*) (34th week) (refer to Figure PC 1).

PC 2.3.9 ***STEP c) and STEP d). Data Collection for Market and Network Studies***

PC 2.3.9.1 By *week c*) (42nd week) (refer to Figure PC 1), and based on the previous analysis in Step b), the **Grid Operators** shall complement the **Information** with the set of national data needed for the market analysis.

PC 2.3.9.2 The required **Information** for each **Scenario** shall comprise forecasts of the **Demand**, the power **Generation** mix, the merit order dispatch of conventional **Generation Units** (based on standard costs of fuel and standard efficiency per type of **Generation Unit**) and the **NTC** between neighbouring interconnected **Power Systems** in the format required by the adopted simulation tool and the **Grid Models**, with and without the proposed transmission projects. According to the configuration of the internal **Power System** of each **Member State**, the **WG4** could require one or more **Grid Operators** to simulate the market separating the national system in two or more zones.

PC 2.3.9.3 The **WG4** shall define market **Scenarios** driving **KPIs** (economics, reliability, adequacy). By *week d*) (46th week) (refer to Figure PC 1), **Grid Operators** shall approve the **Scenarios**.

PC 2.3.10 ***STEP e) and STEP f). Market Analysis***

PC 2.3.10.1 The **WG4** or the relevant **Expert Group** shall perform the market studies. Simulations shall be performed adopting a stochastic approach in accordance with **Good Utility Practices**. Market studies shall produce, for each **Scenario** and transmission project, the values of the **KPIs** taken as reference for **Adequacy** and socio-economic welfare.

PC 2.3.10.2 The **WG4** shall also deliver for each transmission project, the results of Market/**Adequacy** analyses and complete their delivery not later than *week e*) (62nd week) (refer to Figure PC 1).

PC 2.3.10.3 **Grid Operators** shall discuss results and endorse final versions by the *week f*) (66th week) (refer to Figure PC 1).

PC 2.3.11 ***STEP g). Network Set-up***

PC 2.3.11.1 The relevant **Expert Groups** shall perform network analysis based on the results of market study, in order to check the compliance with security standards if the conditions of the market studies are applied.

PC 2.3.11.2 For this purpose, the relevant **Expert Groups** of **WG4** shall agree on a set of **Snapshots** per transmission project which are recognized as significant to operations in peak and off-peak hours and in various seasonal situations.

PC 2.3.11.3 The market simulation variables of the **Snapshots** shall be taken from the simulations of the market studies and mapped onto the **Individual Grid Models** and then merged into a **Grid Model** per study area – as defined in PC 4.2 – carved out of the **Common Grid Model** and per

Snapshot. Alternatively, variables can be directly mapped in a **Grid Model** per study area carved out of the **Common Grid Model**, resulting from previously merged individual data provided by each **Grid Operator**.

- PC 2.3.11.4 Each relevant **Expert Group** shall agree on the segments of **Transmission Systems** that can be represented with equivalents to reduce the calculation burden, without appreciable loss of accuracy.
- PC 2.3.11.5 The preparation of the **Grid Models** per study area shall be concluded by *week g*) (72nd week) (refer to Figure PC 1).

PC 2.3.12 **STEP h) and STEP i). Network Studies**

- PC 2.3.12.1 Each relevant **Expert Group** of the **WG4** shall coordinate the **Network** studies by running load flow studies on the **Common Grid Model** set up according to PC 2.3.11. Security standards shall be assessed with such studies and, if needed, reinforcements are considered.
- PC 2.3.12.2 The applicable security standards shall be the same as prescribed in the **Operation Code**. **AC** load flow simulations are recommended. Simplified **DC** models are allowed if they are consistent with the uncertainties of the **Development Planning** processes and/or if it is advisable to run a high number of simulations on a high number of **Snapshots**.
- PC 2.3.12.3 The **WG4** shall carry out short-circuit studies and include the needed provisions to improve the withstand capability in the recommended **Network** reinforcements, according to the **National Grid Codes**, or applicable technical rules.
- PC 2.3.12.4 In case the **WG4** considers the **AC** load flows not sufficient to assess the **Security of Operation**, **Grid Operators** shall perform accurate stability studies. Such studies shall be mandatory and performed with the support and supervision of **WG4** when the **VRES** penetration is above the threshold of 20% of the peak load of a given area.
- PC 2.3.12.5 Stability studies shall include, depending on the detected problems, transient and frequency stability, small signal stability and voltage collapse.
- PC 2.3.12.6 **Grid Operators** supported by the **WG4** shall deliver the results of their stability studies by week h) (82nd week) (refer to Figure PC 1).
- PC 2.3.12.7 Discussions on **Network** studies shall be concluded by week i) (86th week) (refer to Figure PC 1).

PC 2.3.13 **STEP j). Cost Benefit Analysis**

- PC 2.3.13.1 **Grid Operators** in the relevant **Expert Groups** shall conduct the cost benefit analysis for each transmission project and send the results to **WG4** by *week j*) (94th week) (refer to Figure PC 1).

PC 2.3.14 **Step k). Approval and publication of a Priority Plan**

PC 2.3.14.1 After validation of the **Priority Plan** by the **Grid Operators**, **WAPP** shall submit the **Priority Plan** to **ERERA** for opinion and subsequently to **ECOWAS** for approval.

PC 2.3.14.2 **ERERA** shall, prior to issuing its opinion, open a public consultation in accordance with its procedures.

PC 2.3.14.3 Once approved by **ECOWAS**, **WAPP** and **ERERA** shall publish the **Priority Plan** on their websites by week *k*) (100th week) (refer to Figure PC 1).

PC 2.4 Project Ranking Against Targets

PC 2.4.1 The **Priority Plan** shall include quantitative elements for a transparent ranking process, where necessary.

PC 2.4.2 The **WG4** is entitled to develop a draft priority list against given targets, at the end of the analysis and compile the list only if required.

PC 2.5 Disputes on the Results

PC 2.5.1 Disputes are regulated by GC 8 of the **General Conditions**.

PC 3. THE DATA INFRASTRUCTURE

PC 3.1 Central Database for Network and Market Studies

PC 3.1.1 The planning process, designed to guarantee the coordination among **Grid Operators**, requires efficient **Data Exchange** and a secure data repository managed by the **WAPP**. For this purpose:

- a) **Grid Operators** shall cooperate to set up a **Central Database** to be gradually implemented no later than two (2) years from entry into force of this **Planning Code**.
- b) **WAPP** shall propose the technical solutions and the relation/integration with other dedicated data repositories (e.g., data for tariff computation).

PC 3.1.2 The basic contents of the **Central Database** shall be organized in logical sections as follows:

- a) section dedicated to the market and **Adequacy**;
- b) section dedicated to network analysis; and,
- c) section dedicated to statistics and reporting.

- PC 3.1.3 Dedicated interfaces shall guarantee efficient exchanges of **Information** between the **Central Database** of **WAPP**, the **Individual Database** of each **Grid Operator** and the database of the **SMO**, primarily to avoid double work in uploading data in more than one **Individual Databases**.
- PC 3.1.4 The **WG4** shall coordinate the central activities in co-operation with the **SMO**. **WAPP** will be responsible for the acquisition of the resources for design, deployment and maintenance of the **Central Database**.
- PC 3.1.5 The location of the **Central Database** in physical servers or cloud solutions shall be agreed among the **Grid Operators** considering costs and cyber security criteria.

PC 3.2 Interoperability of Evaluation Tools

- PC 3.2.1 **Evaluation Tools** are the package of models for market analysis, **Adequacy** analysis and network analysis. In principle, each **Grid Operator** shall have the capability to verify results of its interest.
- PC 3.2.2 For purposes of such evaluations, **WAPP**:
- a) is responsible for the design, the implementation and the maintenance of the **Central Database**;
 - b) Is required to:
 - i. select and adopt solutions based on standard software;
 - ii. agree with **WAPP Members** the best solutions to convert the formats of the **Central Database** into the formats of the **Evaluation Tools** adopted by the **Grid Operators** and vice versa;
 - iii. make available ancillary software to upload and download data and **Grid Models**.
- PC 3.2.3 The **Grid Operators** shall actively contribute to the database implementation from the specification phase. The following will be required from the **Grid Operators**:
- a) the declaration of the tools used in their respective companies;
 - b) the declaration of any changes of packages used;
 - c) the decision on common formats to be adopted;
 - d) their willingness to share costs;
 - e) their availability to take part in the design;
 - f) their availability to perform type and acceptance tests, and database population.
- PC 3.2.4 The **Grid Operators** shall consider, as a matter of priority, the continuous update and upgrade of their network analysis software packages, including interoperability.

PC 4. GUIDELINES & METHODOLOGY

PC 4.1.1 This **Planning Code** pursues the objective to make available to the **Member States** guidelines, methodologies and cooperation models for the sole purpose of taking advantages of a synergic approach. PC 4.2 and PC 4.3 are guidelines to evaluate the advantages of the proposed transmission projects for the benefits of the **REM**.

PC 4.2 Study Area Systems

PC 4.2.1 In the application of this **Planning Code**, the **Grid Operators** shall consider the wide extension of the **Region** and the differences in level of development of the **Grid Operators** including the fact that some of the **Grids** are still **Islands**.

PC 4.2.2 The network study approach in this **Planning Code** shall refer mostly to study areas (i.e., coherent portions of the **WAPP Power System**) because the grid calculations are easier to be handled.

PC 4.2.3 A study area may be all or part of the **Region**, agreed within the **WG4**, even if it is an area which is not synchronized but considered relevant for the grid analysis as per article PC 4.2.6.

PC 4.2.4 A study area shall comprise two (2) or more neighbouring **Grid Operators** that have interconnection projects to be implemented in common.

PC 4.2.5 The proposed **Development Planning** methodology, however, applies in general, regardless of the physical distances, and gives values to the differences related to demography, economy, time zone shifts, etc., in the market simulations.

PC 4.2.6 The **WG4** shall define study areas at each planning cycle and assign an **Expert Group** to each of them.

PC 4.2.7 Study areas shall be revised as soon as **Cross-border Interconnection** projects connect the **Islands** to the **WAPP Power System**. Revisions could result in an enlargement of the study areas when an **Island** is synchronously connected to a study area, or a merger in case new **Cross-border Interconnections** connects the two study areas.

PC 4.2.8 As far as market studies are concerned, the building blocks are nodes of the **Power Systems** of **Member States**. Each **Grid Operator** is simulated with a node and connected with the others with a link whose capacity is the existing **NTC** or proposed in the transmission projects.

PC 4.3 Objectives of a Development Planning

PC 4.3.1 **Grid Operators** shall commit to convene on a regular basis, as they determine, to issue the **Master Plan** for the **WAPP Power System**. The main objective of **Transmission System** planning in the **Region** is to ensure, based on multilateral cooperation sponsored by **Member States**, the development of an adequate **Transmission System** to facilitate the development of the **REM** and:

- a) provide a high level of **Security of Supply (SoS)** in all the study areas of the **Region**.
- b) ensure the **Security of Operation (SoO)** of the whole **Region**.
- c) contribute to the availability of electricity at reasonable costs to engender sustainable development of the **Region**.
- d) contribute to the economic efficiency of the entire **Region**.
- e) promote and potentiate the integration of **RES** in the **Region**.
- f) promote internal market integration and the harmonization of the rules.
- g) facilitate fair access to the **Transmission System** by all **Market Participants**.

PC 4.4 Assumptions

PC 4.4.1 For the purposes of PC 4.3, the **WG4** shall verify the degree of relevance of each **Member State's** transmission projects with respect to the shared objectives of **Member States** in the **Regional Electricity Market Regulation (REMR)**, through a transparent assessment process based on the following assumptions:

- a) The data received by the **Grid Operators** are reliable and consistent with the ones adopted in their **Development Plans**.
- b) The **Scenarios** are defined and shared among **Grid Operators**.
- c) The methodology and the algorithm for market and **Adequacy** studies and for network studies are transparent and agreed upon.
- d) The data and **Scenarios** received by the **Grid Operators** are consistent with the **Intermediate Planning** and **Long-Term Vision Planning**.

PC 4.4.2 **Grid Operators** shall be responsible for the input data and the assumptions made as a basis for further assessment.

PC 4.4.3 The **Development Planning** methodology and algorithms shall guarantee that the processes are traceable.

PC 4.5 Planning Data Requirements

PC 4.5.1 Within a maximum of eight (8) weeks after the definition of the **Scenarios**, each **Grid Operator** shall provide the **WG4** with the following data about its **Power System**, in the format, definition and detail specified in the database or agreed within **WG4**:

- a) **Load** profiles.
- b) Thermal **Generation** – in aggregate form by **Generation** category – in terms of size, primary fuel, maintenance, base **Load**, must run, reliability, flexibility degree.
- c) **Generation** and CO₂ costs, in aggregate form by **Generation** category. The **Member States** should harmonize this information with fixed cost in relation to primary source and efficiency.
- d) Value of loss of **Load** associated with unsupplied electricity, based on a harmonized process defined by the **Member States**.
- e) Electricity production from hydro-based **Generation Facilities** (run-off-river, natural inflow, reservoirs, etc.) and pump/storage capacity, in aggregate form by **Generation** category.
- f) Electricity production profiles or producibility from solar- and wind-based **Generation Facilities**, in aggregate form by **Generation** category.
- g) Electricity production profiles or producibility from all the other **RES Generation Facilities**, in aggregate form by **Generation** category.
- h) Power margins.
- i) Number of nodes needed for the market modelling by each **Member State**.
- j) **NTC** and **TTC** at all its borders and intra **Grid**.
- k) Energy transfer towards neighbouring **Power Systems** that do not belong to the **Region**.
- l) Others (such as limitations in the use of water, exchanges planned and long terms bilateral or multilateral contracts between **Grid Operators**).
- m) Load flows on reference **Networks** at the end of the planning horizon (i.e., **Individual Grid Models**).
- n) Single line diagrams of the **Grids**.
- o) Dynamic **Grid Model** for further simulations at the level of **WAPPITS**.
- p) Large **Demand Facilities** information is requested if the related load is part of a demand side management strategy, in aggregate form.

PC 4.6 Reference Scenarios

- PC 4.6.1 **Scenarios** are possible situations that can happen in the future. **Scenarios** are quantitative descriptions of the future status or statuses of a **Power System**.
- PC 4.6.2 **Scenarios** have a fixed number of parameters in common, but they differ from each other in the weighting factor that each of them assumes.
- PC 4.6.3 Unless otherwise arranged by the **WG4**, to represent the socioeconomic and the environmental policies of the **Region**, **Grid Operators** shall weight and define not more than six (6) macro factors expressed by one or more significant parameters:
- a) Economy (Gross Domestic Product (GDP) growth, population growth, **Demand** forecast, primary resources price).
 - b) **RES** penetration plans and boosting tendency.
 - c) Technology development (storage, load management, smart grid).
 - d) Expected new **Demand** (water desalination, electric cars, public transportation, energy efficiency).
 - e) Market integration (domestic market, **REM**);
 - f) Carbon-free and carbon-neutral thermal technologies.
- PC 4.6.4 The **WG4** and **Grid Operators** shall agree on a set of **Scenarios** based on the parameters that were previously chosen.
- PC 4.6.5 **WG4** and **Grid Operators** shall define from two (2) to four (4) **Scenarios** as a combination of the weights assigned to each of the selected parameters.
- PC 4.6.6 Unless otherwise arranged by the **WG4** and **Grid Operators**, or in case of lack of agreement, the choice could be made from typical **Scenarios** like the following (see also ANNEX A – EXAMPLE OF DEFAULT SCENARIO SELECTION) and duly adapted to the **Region** framework:
- a) **S1. SoS** improvement in a flat business trend.
 - b) **S2. Gas** and local integration of **RES**.
 - c) **S3. Fast economic growth** supporting the development of **Cross-border Interconnections** but low thermal plants development.
 - d) **S4. Sound environmental targets** and market integration at **Region** level.
 - e) **S5. Environmental sustainability** mutually approached. That is, the environmental challenges represent a common objective of more **Member States**.
 - f) **S6. Low economic development** with **SoS** improvement.

PC 4.6.7 The **WG4** may decide to modify the **Scenarios** on the basis of the preliminary results of the analysis.

PC 4.6.8 Unless otherwise arranged by the **WG4**, the contribution of each transmission project in each **Scenario** to the improvement of the following indicators shall be calculated by means of simulation of the coverage of the **Demand**, performed according to the applicable market rules. Such indicators shall be included in the category of the benefits within the cost-benefit analysis of the new transmission projects, and defined as follows:

- a) *Improved SoS*, that is the ability of a **Power System** to provide an adequate and secure supply of electricity under ordinary conditions. For this purpose:
 - i. the **Expected Energy Not Served (EENS)**, **Loss of Load Expectation (LOLE)**, and **Loss of Load Probability (LOLP)** are calculated.
 - ii. Reference values of **EENS**, due to lack of interconnection capacity, are between 0,002 and 0,02% of the yearly **Demand** and reference values for **LOLE** are between 2 and 48 hrs/year at the 95 percentiles. Such values are considered targets to be progressively reached.
 - iii. Reference values are long term targets to be considered in the evaluation of the progresses in planning. In case the cumulative parameter of the projects of a plan is outside such ranges, the WG4 shall investigate the reasons and report on the findings.
- b) *Socio Economic Welfare or market integration*: that is the ability of a **Power System** to reduce the power **Congestions**, and thus provide enough capacity of the **Transfer Capacity** for the electricity markets and allow the development of a trading system in an economically efficient manner. The increase of **NTC** shall be calculated.
- c) *Integration of RES*: that is the two-fold ability of a **Power System** to accommodate new **RES-based Facilities** and to minimize the curtailment of the **RES-based Facilities**. The concept of **RES** integration shall include solutions to maximize the cross-border power exchanges in hours of overproduction as alternative to curtailment.
- d) *Reduction in CO₂ emissions*: that is the characterization of the reduction of CO₂ emissions in the **Power System**. Volume of reduced CO₂ shall be calculated.

PC 4.6.9 The evaluation of the impact of a single transmission project on the indicators shall be performed by comparative analysis of the values with and without the transmission project:

- a) Method 1: to calculate the differences between the values assumed by simulating as if all the transmission projects have been implemented, and the same values assumed by excluding the transmission project to be assessed.
- b) Method 2: It is also possible to start from the situation where no transmission project has been implemented and calculate the differences in values assumed by the parameters adding the effects of the transmission project to be assessed.

- c) Without prejudice to the decisions agreed by the **WG4**, Method 1 is preferred when the grid complies with the targets of the common planning process, while Method 2 is preferred when one or more transmission projects are added to a consolidated reference grid.

PC 4.7 Adequacy and Market Studies Methodology

- PC 4.7.1 Stochastic simulations of the coverage of **Demand** in each **Grid Operator's Control Area** shall be performed in the market studies.
- PC 4.7.2 Simulations shall be driven by the applicable rules of the **REM**. The simulation shall assess the **Adequacy** in the **Power System** of each **Member State**, with and without the transmission project(s).
- PC 4.7.3 The stochastic simulations shall account for relevant uncertainties of the inputs, including but not limited to, **Load** and **Generation** profiles, **RES** production, weather (i.e., **V-RES** availability), hydrometry.
- PC 4.7.4 The results of the **Adequacy** simulations give quantitative **Information** about the **Adequacy** of **Generation** in each **Member State** and its market zone.
- PC 4.7.5 Market zones are simulated as single nodes. The exchanges between market zones are characterized by the **TTC** between them.
- PC 4.7.6 The benefits of each transmission project shall be evaluated in terms of the selected indicators (see EXAMPLE OF DEFAULT SCENARIO SELECTION for an example of possible **Scenarios** and weight assignment).
- PC 4.7.7 The market studies shall highlight the number of hours in which one or more borders are filled up by the resulting energy transfer and the cases where there is still room for beneficial development of **Cross-border Interconnections**. The **WG4** shall make available such indications to the **Grid Operators** as a signal to be taken into consideration for the **Priority Plan** in progress and for the future. These indications can be used by **ECOWAS** to provide signals of investment opportunities in these borders.
- PC 4.7.8 The **WG4**, in cooperation with market committees of **WAPP** and on the basis of the **Development Plans**, may propose projects to create a suitable market, tariff and physical conditions to regulate the cross-border trading of energy with the ultimate goal to suppress any necessity of **Curtailment**.

PC 4.8 Network Study Standard Methodology

- PC 4.8.1 Network studies shall verify the capability of the **Transmission System** to sustain the load flows under the conditions simulated by the market studies and comply with security standards for all hours of the year.
- PC 4.8.2 To simplify the process, it can be allowed to reduce the number of simulations, by relying on relevant **Snapshots**, performing calculations for the hours considered significant and representative for the whole year, as prescribed in this **Planning Code**.
- PC 4.8.3 ***Snapshot Selection***
- PC 4.8.3.1 A set of **Snapshots** for the network analysis are identified from the results of the market studies, by selecting the power in-feed and out-feed in hours revealing probable stresses on the **WAPP Power System** (e.g., peak and off-peak hours, max and min export / import or most frequent hours for loss calculations).
- PC 4.8.4 ***Steady State Simulation Against Contingency Lists***
- PC 4.8.4.1 Each **Snapshot** shall be merged with the Individual Grid Model, by assigning the in-feeds and out-feeds of the **Snapshots** to the nodes of the Individual Grid Model. Such generated networks shall be simulated until convergence in order to have as many consistent situations as the selected **Snapshots**.
- PC 4.8.4.2 The security assessment is performed on each of the **Snapshots** according to the criteria adopted, assumed in the **Operation Code**, and to the requirements prescribed in the **Connection Code**.
- PC 4.8.4.3 Simulations shall not include the already applied **Wide Area Protection Systems** if introduced by **Grid Operators** to manage temporary inadequacies of the **Transmission System**.
- PC 4.8.4.4 In case of violation of security limits, reinforcements can be suggested by the **WG4. Grid Operators** take the responsibility to accept or refuse or propose further solutions for further verification.
- PC 4.8.4.5 After the network studies, two (2) further indexes shall be calculated:
- a) The variation of losses with and without the transmission project under assessment.
 - b) **SoO** improvement with the transmission project under assessment.
- PC 4.8.4.6 Technical operation limits shall be prescribed in the **Operation Code** and the **Connection Code**.
- PC 4.8.4.7 Security standards shall be prescribed in the **Operation Code** and the **Connection Code**.

PC 4.8.4.8 The criteria for identifying contingencies and defining the **Contingency List** shall be prescribed in the **Operation Code** and the **Connection Code**.

PC 4.8.5 **Short Circuit Studies**

PC 4.8.5.1 Three phase faults and single phase to ground faults shall be calculated according to IEC 60909 in the simulations to verify the breaking and making capacities of the circuit breakers.

PC 4.8.5.2 If the Short-Circuit Current exceeds 90% of the rated value of the breaking capacity of the circuit breakers, the replacement of circuit breakers shall be included in the reinforcements associated with the transmission project under assessment in the cost-benefit analysis. In the same case the replacement of the circuit breakers could not be the solution or the only solutions, for example, splitting the substation in two substations or revising the earthing could be necessary to be considered.

PC 4.8.5.3 Minimum short-circuit current calculations shall be required at the terminals of the **HVDC Systems** to guarantee the proper functioning of the **DC** link and its protection system.

PC 4.8.6 **Stability Studies**

PC 4.8.6.1 Stability studies should include: voltage collapse, frequency stability, transient stability and angular stability.

PC 4.8.6.2 In the case of a first **AC Cross-border Interconnection** between two (2) study areas, these studies shall be carried out by the involved **Grid Operators**. In this case the stability studies go beyond the simple assessment of the transmission project because they could concern a general assessment of the compatibility of two study areas. The **WG4** shall manage these cases with special commissions tasked to assess all aspects of such **Cross-border Interconnection** as per PC 4.9.

PC 4.8.6.3 In other cases, given the complexity of the studies and the amount of data and their quality, the **WG4** may allow the performance of such studies or part of them with simplified models or postponement when the detailed design of the **Cross-border Interconnection** starts.

PC 4.8.6.4 Dynamic security analysis shall be done as per article PC 2.3.12.4.

PC 4.9 **Additional Studies**

PC 4.9.1 In case a transmission project is the first **Cross-border Interconnection** between two **Grid Operators** belonging to different study areas, or one of them is an **Island**, the **WG4**, in cooperation with the **SMO**, and the involved **Grid Operators**, shall carry out and submit an overall feasibility study covering at least:

- a) Short-Circuit Current studies.
- b) Compatibility of practices adopted in operation.
- c) Compatibility of the **SCADA** systems.

- d) Time required to bridge the gaps, if any.

PC 4.9.2 In case the same first **Cross-border Interconnection** is an **AC** technology, the following is required:

- a) Stability studies with due attention to the **Power System Stabilizer** policy and settings.
- b) **Automatic Generation Control (AGC)** standard.

PC 4.9.3 Where such studies show that modifications are necessary, then the means and timelines to implement these modifications must be established before the time of implementation of the transmission project reported in the **Priority Plan**.

PC 4.10 Cost Benefit Analysis

PC 4.10.1 Cost-benefit analysis shall be presented project by project in uniform editorial pattern, in order to facilitate ease of reading. For each transmission project the following sections are required:

- a) General settings: where at least the technical features of the transmission project are described, and the status of the transmission project is reported. It is required to specify if the transmission project is in one of the following stages: under consideration; planned, but not yet in permitting; under construction; commissioned; cancelled.
- b) A section dedicated to the investment shall report:
 - i. The total costs (including the capital costs) of the transmission project and the ratio between the main work and the reinforcements.
 - ii. The associated OPEX.
 - iii. Costs for compensation works (e.g., compensation for persons affected by the projects, environmental compensations, development levies).
 - iv. A description of the investment costs per item. Items shall be described in number or engineering quantities at functional level (e.g. line, circuit breaker) and voltage level.
- c) A section dedicated to the benefits shall include the results of simulations per **Scenario**. For each **Scenario** at least:
 - i. The **TTCs** (in import and in export and for both interconnected **Power Systems**) with and without the transmission project.
 - ii. The ratio between the **TTC** and the sum of all the **Generation Capacity** installed to evaluate what could be a limit to the import / export of electricity.
 - iii. The **KPIs Scenario** by **Scenario** mentioned in article PC 4.7.6.
 - iv. Residual indicators like environmental impact, social Impact, and other impacts to be highlighted by the **WG4**.

PC 4.10.2 Standard unit costs shall be adopted in cost-benefit analysis. Unit costs shall be approved by the **WG4** before starting the cost-benefit analysis process. The **WG4** shall also approve the differences country by country where applicable (e.g., due to labour cost, special laws, compensations).

PC 4.11 Cross-border cost allocation

PC 4.11.1 Cross border cost allocation is subject to **Bilateral Contracts**. Fairness on the evaluations is recommended.

PC 4.12 Minimum Requirements of Individual Databases and Evaluation Tools

PC 4.12.1 **Individual Databases** should contain at least the same set of **Information** and set of data of the corresponding sections of the **Central Database**.

PC 4.12.2 Market simulations, based on stochastic algorithms, should be run with the same software or software compatible with the one used at central level, to facilitate the comparison of results.

PC 4.12.3 Network studies can be performed using tools whose only requirement is the easy interface with the software adopted at central level.

PC 4.12.4 To bridge the gap in modelling of **HVDC System** inverter-based **Generation Facilities**, sharing the models should be mandatory for the benefit of the quality of the simulations.

PC 4.13 Study-area approach

PC 4.13.1 **Grid Operators** belonging to a study area neither yet interconnected with the rest of the **WAPP Power System** nor proposing interconnection transmission projects with any of the **Grid Operators** external to such study area, can decide to autonomously handle their transmission projects and nominate a study area facilitator as an internal coordinator.

PC 4.13.2 The facilitator referred to in article PC 4.13.1:

- a) may represent the study area in the **WG4**.
- b) shall develop the **Power System** of the study area according to the rules of this **Planning Code**.
- c) shall contribute to the **Priority Plan** with the conclusions on expansion transmission projects of the **Member States** of the study area. These transmission projects shall be described with the same **Information** adopted for the entire **Region**.

PC 4.13.3 For a seamless future integration of the study areas with the **Power Systems** outside the study area itself, the facilitator is obliged to take part in the simulations and share the results of its area.

PC 4.13.4 In case of **Cross-border Interconnections** projects between a **Grid Operator** of the study area and an external one, the transmission project shall be developed according to the applicable bilateral agreement but evaluated with the criteria stated in this **Planning Code**.

PC 4.14 Temporary Reductions of the Scope of Priority Plan

PC 4.14.1 It is faculty of the **Grid Operators** to decide to limit the objectives of PC 4.3 in the first issue of the **Priority Plan** strictly to the **Regional Electricity Market Regulation (REMR)** prescription. This requires:

- a) The presentation of transmission projects significant for the present objectives.
- b) The selection of a reduced number of **KPIs** in the market and **Adequacy** studies.
- c) As an alternative to b), simplified network studies could be run, but in this case the comparison of transmission projects would risk being of scarce significance.

PC 4.14.2 This version of the **Priority Plan** could be identified as a preliminary version of the **Priority Plan**.

PC 5. LONG-TERM VISION PLANNING

PC 5.1 Terms of the Long-Term Vision Planning

PC 5.1.1 The **Long-Term Vision Planning** activity of planning covers a time horizon of twenty (20) to thirty (30) years and beyond.

PC 5.1.2 The time horizon of the **Long-Term Vision Planning** activity may also be set from time to time according to significant target years fixed at ECOWAS level to reach given results.

PC 5.1.3 Objectives of the **Long-Term Vision Planning** are to define the **Long-Term Targets (LTT)** for the **Flexibility** of the **Grids** and the development of **Cross-border Interconnections**, and the formulation of long-term strategies to reach the **LTTs**.

PC 5.1.4 The **LTTs** agreed at Governmental level and adopted at ECOWAS level have priority over the ones proposed by **Grid Operators**.

PC 5.1.5 The **LTTs** shall be taken as a reference for the **Priority Plans** and the related strategies have to be applied in the **Intermediate Planning** and **Priority Plan Development** by the **Grid Operators**.

PC 5.1.6 The **Grid Operators** shall contribute to the **Long-Term Vision Planning** activity within the **WG4**.

- PC 5.1.7 The **WG4** shall support the **Grid Operators** in dissemination of the results about the **Long-Term Vision Planning** activity and **LTTs**, and promote their implementation at national level.
- PC 5.1.8 The **Development Plans** should take into account the results of the **WG4** activity, as endorsed by **WAPP**.

PC 5.2 Deliverables of the Long-Term Vision Planning activity

- PC 5.2.1 The **Grid Operators** and **WAPP** through **WG4** shall carry out, at least every three (3) to six (6) years or unless **Member States** agree upon a different timing, a **Long-Term Vision (LTV)** document including at least:
- a) The strategy of the **Region** to reach the selected **LTTs**. Part of the strategy shall include the parameters to be adopted in the **Scenario** evaluations. These parameters could be, e.g., the levels of CO2 reduction, **Grid Flexibility**, inertia of the **WAPP Power System**.
 - b) The guidelines to address the **Long-Term Vision Planning** actions.
 - c) The action plan to approach and organize the future activity.
- PC 5.2.2 The document referred to in article PC 5.2.1 shall be submitted for public consultation, and for **ERERA's** and **ECOWAS's** consideration and opinion. After the **WAPP** internal approval, they are published together with the results of consultations.
- PC 5.2.3 The **WG4** shall elaborate **LTTs** for the **Region**, taking into account:
- a) The guidelines and international commitments of **ECOWAS**, which include also potential regional guidelines and/or agreements on the implementation of the national commitments taken by the **Member States** in the framework of the international Climate Change Conference of the Parties process.
 - b) The national strategies.
 - c) The needs of the **WAPP Power System**.
- PC 5.2.4 The **WG4** is in charge of discussing and running feasibility studies and evaluations about the **LTTs**. Such studies can include market studies for a number of target years within the **Long-Term Vision Planning** time horizon, selected by the **WG4**, with the aim of estimating scale, benefits and costs of potentially needed interconnections for that time horizon that are consistent with the items to be taken into account in article PC 5.2.3.

PC 6. INTERMEDIATE PLANNING

PC 6.1 Terms of the Intermediate Planning

- PC 6.1.1 The **Intermediate Planning** is the activity necessary to periodically check and provide the information for aligning the **Priority Plan** to the **LTTs**.

PC 6.1.2 **WG4** shall develop and update its methodology for the **Intermediate Planning**, which can include market and network studies, with the aim to derive insights on scale, benefits and costs of potentially needed interconnections for the **Intermediate Planning** time horizon. The **Intermediate Planning** activity delivers the **Intermediate Plan**.

PC 6.1.3 The **Intermediate Plan** shall cover at least:

- a) How progress towards the **LTTs** is evolving.
- b) The suggestions to orient the subsequent **Priority Plans** because of the evolution of the **LTTs**.
- c) Define and recommend the parameters for setting-up the evaluation **Scenarios**.
- d) The preview of proposal of new transmission projects to be further analysed in detail in the next **Priority Plans**.
- e) The perspectives for the period beyond the end of the latest **Priority Plan**.

PC 6.1.4 Unless **WAPP** considers different timing and coordination for the purposes of enhanced efficiency, the following time framework shall be considered:

- a) the time horizon of the **Intermediate Planning** is ten (10) to fifteen (15) years with focus on the next years not covered by the last **Priority Plan**, i.e. between ten (10) and fifteen (15) years ahead.
- b) the **Intermediate Planning** is updated every six (6) years.

PC 7. GENERATION ADEQUACY FORECAST

PC 7.1 Long-term Adequacy forecast

PC 7.1.1 Evaluations are required at single **Grid Operator** level within the energy policy that each **Member State** shall perform by law. In the individual evaluations, the exchange with other **Member States** is simulated.

PC 7.1.2 Based on individual **Adequacy** forecast, the **KPIs** are derived from the market and **Adequacy** centralized studies, as described in PC 4.7.

PC 7.1.3 Seasonal **Adequacy** forecast is matter of the **Operation Code**.

PC 8. FORMAL OBLIGATIONS

PC 8.1 Obligations

- PC 8.1.1 Market studies require processing sensitive **Information**. This circumstance compels the use of conventional standard costs in the cost-benefit analysis.
- PC 8.1.2 **Grid Operators** shall use as much as possible aggregated and anonymous **Information** to avoid the identification of the sources.
- PC 8.1.3 No **Party** may disclose data and **Information**.

PC 9. CENTRALIZATION OF PROCESSING OR COLLECTION OF INITIATIVES

PC 9.1 Principles

- PC 9.1.1 The planning process, as prescribed in this **Planning Code**, requires part of the activity to be independently performed by the **Grid Operators** and part which needs to be performed in a centralized way.
- PC 9.1.2 The centralization is required by the assessment of the benefits of a **Cross-border Interconnection** project, the market simulations, the arrangement of **Common Grid Models**, the drafting, the presentation, and the publication of results.
- PC 9.1.3 A **Central Database** contributes to the efficiency of periodical centralized **Development Planning** activities.
- PC 9.1.4 **Grid Operators** of the **Member States** shall:
- a) Forward proposals of transmission projects, as much as possible, defined between neighbouring **Member States**.
 - b) Forward **Development Plans**.
 - c) Carry out security analysis.

ANNEX A – EXAMPLE OF DEFAULT SCENARIO SELECTION

A.1.1 This Annex describes an example of possible **Scenarios**. The example can be proposed as a basis for discussion and to trigger the planning process at the first time. Two macro areas are taken as part of generic **Region**. They are called Area A and Area B. Area A is characterized by mature level of development with signals of stagnation while Area B is characterized by a fast growth in economy and population.

A.2 Scenarios

A.2.1 ***S1. SoS Improvement in a Business-As-Usual Trend***

A.2.1.1 This is a conservative **Scenario**.

A.2.1.2 The **Load** consumption increases with the same trend in each **Member State**.

A.2.1.3 The economic development in most **Member States** is between 4 and 6% on average.

A.2.1.4 Energy policy is marked by the continuation of the current trend in each country. The policy of supporting **RES** is pursued but their growth remains well below the level seen in the other countries in Area A.

A.2.1.5 The scope of **Cross-border Interconnection** projects and internal **Grid** projects are based on the improvement of the **SoS**.

A.2.2 ***S2. Gas and local integration of RESs***

A.2.2.1 This **Scenario** is a more environmentally sustainable **Scenario**, based on a bottom-up approach.

A.2.2.2 **Member States** decides a common policy to integrate **RESs** and maximize the effort to reduce climate changes.

A.2.2.3 The CO₂ price is high in Area A. The policy of the countries in Area B is based on an attentive use of primary resources and the development of **RES** funds with primary resources incomes.

A.2.2.4 Gas power plants are built in the Area B for the guaranty of supply and to minimize CO₂ emissions. These gas power plants also will have to be flexible to deal with a new energy mix based on **RES**.

A.2.2.5 The **Load** consumption increases higher than the same S1 trend in each **Member State** because of the development of new electricity uses like public transportation in the countries in Area A and for the demographic increase.

A.2.2.6 The hypothesis on the economic environment is one of the partial cash-up phases of global **Demand** in the **Grid Operators** of Area A. The development in the Area B is between 4 and 6%.

A.2.2.7 Interconnection development in the Area B is based on the improvement of the **SoS** and exportation of **RES**.

A.2.3 ***S3. Fast economic Growth Supporting the Development of the Cross-border Interconnections but Low Thermal Plants Development***

A.2.3.1 This **Scenario** assumes that following the availability of new primary resources, the economy of the **Region** increases especially in the countries of Area B. A 7 % GDP growth could be expected in the Area B and 2 % for the Area A.

A.2.3.2 Countries in Area B decide to develop carbon-free thermal power plant to support the electricity **Demand** without consuming their primary resources.

A.2.3.3 New **Cross-border Interconnections** are built to share the low-cost electricity of this kind of power plants and to share production margins.

A.2.4 ***S4. Sound Environmental Targets and Market Integration at Regional level***

A.2.4.1 This **Scenario** is based on an approach with two (2) issues:

- a) The CO₂ reduction for electricity production and for transportation (new electricity uses).
- b) High technology development for **Load** and **Generation** management especially in the countries in Area A.
- c) The investment in **RES** and carbon-free thermal generation in the Area B to support electricity **Demand**, to limit the consumption of primary resources and to export the surplus of electricity.

A.2.4.2 This **Scenario** is based on many **Cross-border Interconnections** to support the **REM**.

A.2.5 ***S5. Environmental Sustainability Mutually Approached***

A.2.5.1 This **Scenario** is an in-between **Scenario** regarding S3 and S4, where the **Member States** shall increase their cooperation to optimize their **Power System** and setting national environmentally sustainable energy policies.

A.2.6 ***S6. Low progress with SoS improvement***

- A.2.6.1 This **Scenario** is the worst-case **Scenario** for the **Region**. Due to a low economic development of the economy, each **Member State** limits the implementation of **Cross-border Interconnections**. **Grid** reinforcements are focused on the **SoS**.

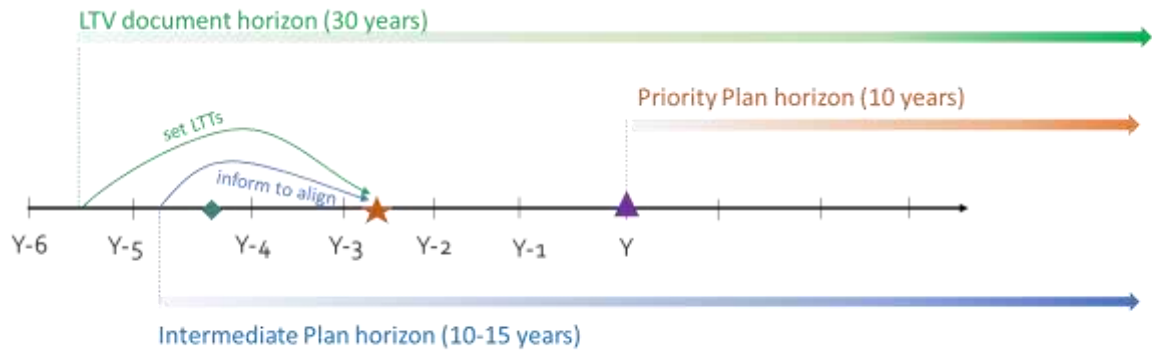
A.3 Weight of parameters vs. Scenarios

- A.3.1 An example of parameter weighting that may be used for the simulations for each **Scenario** (in scale from 0 to 3) are reported in the table below.

Table 1. An example of parameter weighting that may be used for the simulations.

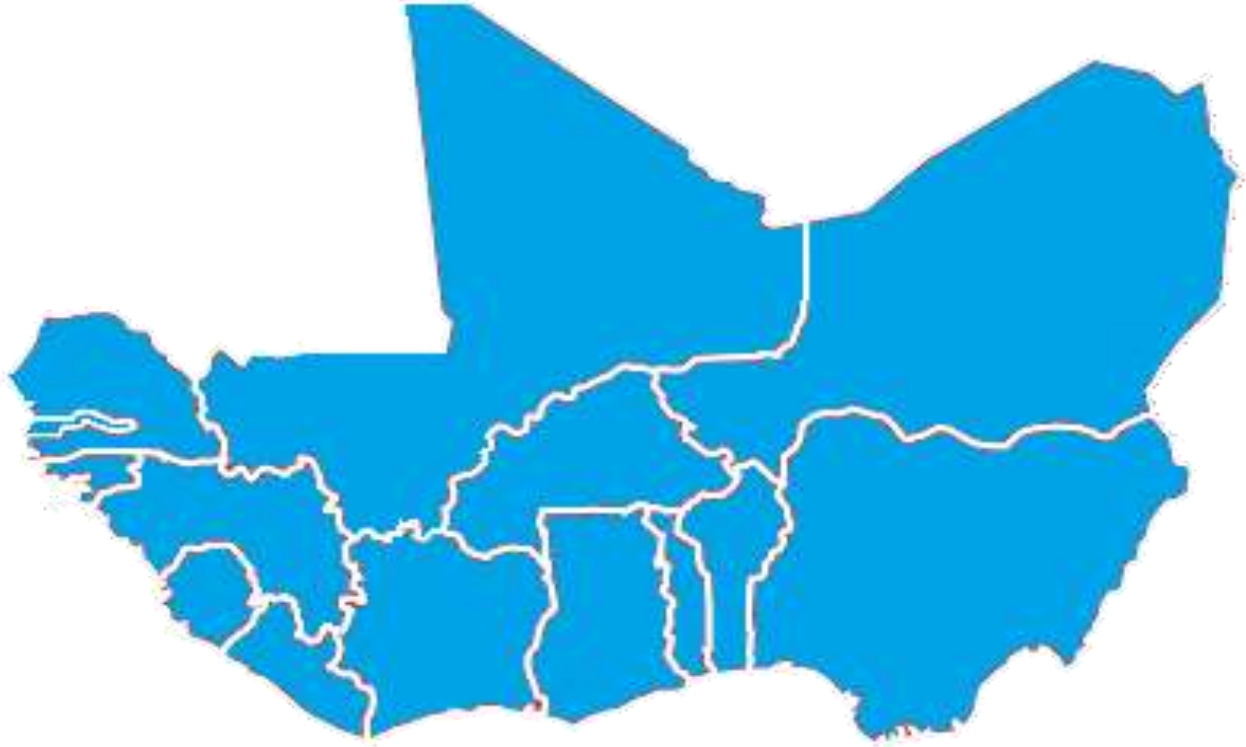
Parameters \ Scenarios	WEIGHTS					
	S1	S2	S3	S4	S5	S6
Economy (GDP growth, population growth, Demand Forecast , primary resources price);	2	2	3	2.5	2	1
RES penetration;	2	2	2	3	2	1
Technology development (storage, load management, smart grid);	2	3	2.5	3	2	1
New Load (water desalination, electric cars, public transportation, energy efficiency);	1	3	2	3	2	1
Market integration (domestic market, REM);	1	1	3	3	2	1
Carbon-free thermal technologies (i.e. nuclear development in the Area B).	1	1	3	3	1	1

ANNEX B – DEVELOPMENT PLANNING TIMEFRAMES



- ★ WAPP starts the development of the Planning.
The duration of the activities for the Priority Plan is 2 years + the approval of ECOWAS
- ◆ Within the 6 years-rolling horizon of Priority Plan development, WAPP can perform its internal checks that are intended to revise/confirm the list of the Priority Projects approved in the previous Master Plan.
- ▲ WAPP is entitled to issue the Priority Plan as a subset of a broader document called "Master Plan", which may include also the outcome of the LTV Planning and the Intermediate Planning, as well as other transmission projects that go beyond the 10-years horizon and not included in the Priority Plan lists.

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



OC – OPERATION CODE

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OC 1. PRINCIPLES OF THE OPERATION OF INTERCONNECTED POWER SYSTEMS

OC 1.1 Object and Scope

OC 1.1.1 The object of this **Operation Code** is to provide the rules and requirements for the safe and coordinated **Functional Operation** of the **Cross-Border Interconnections** in the **Region**. The **Functional Operation** (is related to the control of energy flows, the regulation of frequency and voltage, and any other activity of dispatching in real-time and during **Outage Planning Coordination Business Process**, in both **Normal State** and **Emergency State**. The **Physical Operation** is not part of this **Operation Code**. The **Physical Operation** remains a responsibility related to the ownership of the assets and concerns maintenance procedures, safety, switching and all the activities requiring a physical contact with the assets.

OC 1.1.2 This **Operation Code** and the **National Grid Codes** cover the **Functional Operation** of the tie lines and the **Relevant Grids** affecting the **Total Transfer Capacities (TTCs)** of the **Cross-Border Interconnections**. **Grid Operators'** internal operations, not affecting the **Cross-Border Interconnections**, are regulated exclusively by the **National Grid Codes**.

OC 1.1.3 Neighboring **Grid Operators** shall guarantee that provisions of their **National Grid Codes** and internal **Operational Procedures** that deal with or have impact on **Cross-Border Interconnections** are harmonized with the **REM Codes**.

OC 1.1.4 This **Operation Code** applies to:

- a) **Grid Operators** responsible for **Functional Operations** in their respective **Grids**.
- b) The **SMO** which, as the regional coordinator, interfaces with the **Grid Operators** for the coordination of the **Functional Operation** of the **Cross-Border Interconnections**.
- c) **Generating Facilities** connected to the **WAPPITS**.
- d) **Demand Facilities** connected to the **WAPPITS**.

OC 1.1.5 **ERERA**, in consultation with **WAPP**, shall bear the roles and responsibilities for regulation which require a cooperative support from all the regulated **Entities**

OC 1.2 Responsibility

OC 1.2.1 **Grid Operators** are responsible for the **Security of Supply (SoS)**, **Security of Operation (SoO)**, and economic operation of the **Power Systems**, under their jurisdiction in any phase of the **Functional Operation** and any **Operating Condition** of the **Power System**.

OC 1.2.2 As far as balancing and the **Relevant Grid** are concerned, **Grid Operators** are responsible for the impact of **Functional Operation** of their own systems on systems of other **Grid Operators**.

OC 1.3 Solidarity, Reciprocal Support, Mutual Trust, and Cooperation

OC 1.3.1 **Grid Operators** shall operate their **Grids** to pursue the technical advantages of the interconnected **Functional Operation**, complying with the **Operation Security Standard (OSS)**, as specified in OC 3.2 of this **Operation Code**, and to create the best conditions for cross-border energy trading. To this purpose, each **Grid Operator** shall:

- a) Use all internal resources to avoid spreading any **Contingency** that occurred in its **Power System** to the rest of the **Interconnected Member States**.
- b) Restore the cross-border energy transfers as soon as possible, but not later than a given time (see article OC 8.3.7), to the **Control Area Program** values in **Normal State** conditions – when **Imbalances** occur in its **Power System** – and in **Emergency State** conditions – according to agreed procedures.
- c) Keep intact the **Cross-Border Interconnections** as much as possible in any **Operating Condition** of the **WAPPITS**.
- d) Agree with the neighbouring **Grid Operators** on dedicated procedures to regulate if and when to open **Cross-Border Interconnections**, both in **Normal State** and **Emergency State** conditions, according to the line opening policy defined in article OC 1.5.3.

OC 1.4 Requirements

OC 1.4.1 To maximise the technical and economic advantages of **Cross-Border Interconnection** operations, the **Grid Operators** shall be required to attain the highest levels of interoperability and comparable skills in the control of their **Power Systems**, in organizational set up and adopted tools

OC 1.5 Policies on Security of Operation (SoO)

OC 1.5.1 *General Concepts*

OC 1.5.1.1 The **Security of Operation (SoO)** is the precondition to guarantee a seamless development of the **WAPP Power System** and the quality of supply needed for the prosperity of the whole **Region**. **Grid Operators** shall guarantee the **Security of Operation (SoO)** according to standards compliant with security policies commonly agreed to in this **Operation Code**.

OC 1.5.1.2 **Security of Operation (SoO)** shall be independent of the adopted market regimes. Security standards shall depend on the physical characteristics of the assets and the capability of the **Grid Operators** for controlling their **Power Systems**. Market objectives shall not induce the **Grid Operators** to infringe the **Security of Operation (SoO)** rules.

OC 1.5.1.3 **Grid Operators** shall not use the **Security of Operation (SoO)** rules to favour any participant in the **WAPP Power System**.

OC 1.5.1.4 Procedures for **Security Assessment** shall be agreed at **Synchronous Area** level or **Regional** level. The **SMO** shall perform the calculation and the coordination. The **Grid Operators** shall actively participate in the activity of the **SMO** and adopt the output of the **SMO**'s activities. As a practice:

- a) Steady state load flow analysis should be adequate for routine and systematic day-by-day applications (**Security Assessment**).
- b) **Dynamic Security Assessment (DSA)** studies are recommended and confirmed at **Regional** level, at least for periodic verifications.
- c) **Dynamic Security Assessment (DSA)** is recommended in situations where the **Power Systems** are extremely unloaded, and **Generation** is located far from **Demand**. **DSA** shall include angle, frequency and voltage stability according to the latest **Good Utility Practices** and standards¹ and **Phasor Measurement Unit (PMU)** analysis.
- d) Short circuit studies are prescribed at least yearly or, in particular cases, in protection setting activity.

OC 1.5.2 ***Transitional Provisions Framework***

OC 1.5.2.1 **Grid Operators**, not fully complying with the requirements of this **Operation Code**, shall undertake actions in accordance with the **Transitional Provisions Framework** as per the **General Conditions**.

OC 1.5.3 ***Tie-line Opening Policy***

OC 1.5.3.1 The **Cross-Border Interconnection** lines shall remain closed as much as possible. For this purpose:

- a) The voluntary disconnection of a tie-line, even if temporary, cannot be implemented by the **Grid Operators** without consulting the neighbouring **Grid Operators** and without informing the **SMO** due to the potential effects on the rest of the interconnected **WAPP Power System**.
- b) The voluntary disconnection, either manual or automatic, of tie-lines is permitted for maintenance and when the principle of not spreading a **Contingency** prevails over the principle of keeping the **Cross-Border Interconnection** intact. In this case opening the line should be the last resort to avoid generalized blackouts.

OC 1.5.3.2 A tie-line may be open:

- a) by operation of protection devices;
- b) for maintenance;
- c) for safety and urgent environmental issue;

¹ IEEE/Cigré JTF 2003

- d) in case of fire, bush fires;
- e) to create an **Island** in the framework of the **Defence Plan**.

OC 1.5.3.3 Conditions for permitting tie-lines to be open are:

- a) it must be the ultimate **Remedial Action**, ensuring that this action will not endanger the remaining **Synchronous Area**;
- b) all actions are agreed upon in advance by and duly prepared in a coordinated way with the relevant neighbouring **Grid Operators** and the **SMO**, and communicated before operating the circuit breakers;
- c) in case of manual disconnections, the neighbouring **Grid Operator** and the **SMO** are warned in a traceable way before operating;
- d) in case of automatic opening, settings and logics (e.g., triggering events and if certain thresholds are exceeded) should have been previously agreed upon by the relevant neighbouring **Grid Operators** and the **SMO**;
- e) in case of physical danger to human beings or installations, opening may be carried out without prior Information to the neighbouring **Grid Operators** involved. After the event, the **SMO** shall be informed of it and, with the support of **WAPP**, shall investigate the actual occurrence of the triggering conditions and the admissibility of the action. The **SMO** shall communicate the outcome of this investigation to **ERERA**.

OC 1.6 Control Matters Regulated by this Operation Code

OC 1.6.1 To ensure the reliability of the interconnected **Functional Operation** with minimum impact on national **Grid**, this **Operation Code** shall apply to the following:

- a) The rules relating to **Load Frequency Control (LFC)** in a **Synchronous Area** apply to the completely interconnected **Synchronous Area**, regardless of the voltage level.
- b) The rules concerning the load flow control at the borders apply to the **Relevant Grid**.

OC 1.6.2 The extension of the **Relevant Grid** shall be agreed among the neighbouring **Grid Operators** and the **SMO**. The selection shall be based on the influence that it has on the security and on the cross-border congestions. The following aspects apply to the **Relevant Grid**:

- a) The **Unavailability Plans**.
- b) The **Contingency List**.
- c) The **ATC/NTC** calculations.
- d) The **Security of Operation (SoO)** standards,
- e) The **Wide Area Protection Systems (WAPS)**.

OC 1.7 Organization and Resources

OC 1.7.1 **WAPP**, with the support of the **SMO**, shall establish the following **Working Groups** to assist the **SMO** in carrying out its **Functional Operation** coordination activities:

- a) **WG1-Outage Planning Coordination Working Group** tasked with issues relating to coordination of **Operational** planning.
- b) **WG2-Operation Working Group** tasked with real-time control and related issues. The scope of **WG2** should include control room activities, training of physical operators, **Automatic Generation Control (AGC)**, protection settings, **WAMS**, **WAPS** and operating procedures.
- c) **WG3-ICT Working Group** tasked with issues relating to **ICT** matters and cybersecurity of the **SCADAs** and common **WAN** for **Real-Time Data Exchange**.

OC 1.7.2 The above-mentioned **Working Groups** have no **Functional Operation** duties.

OC 2. TRANSFER CAPACITY MANAGEMENT PROCESS

OC 2.1 Introduction

OC 2.1.1 The process of managing the **Transfer Capacity** is based on rules that define the methodology for calculating capacity up to a year ahead and referred to as long-term capacity calculation.

OC 2.1.2 The **Operational Procedures** regarding this process shall be coordinated by the **SMO**, adopted **WAPP** and approved by **ERERA**.

OC 2.2 Procedure for Calculation of TTC/NTC on the WAPP Interconnected Transmission System

OC 2.2.1 *General Guidelines*

OC 2.2.1.1 **NTC** and **TTC** assessments shall be performed through load flow calculations. The main prerequisites in the assessments are:

- a) A **Grid Model** that allows the determination of the impacts of neighbouring areas (**Common Grid Model**).
- b) Estimated **Generation** and **Demand** profiles to simulate cross-border electricity exchanges (**Base Case**).
- c) A procedure to harmonize and agree on the input data among the concerned **Grid Operators**.

- d) Guidelines to perform the simulations of cross-border electricity exchanges in a most realistic and understandable way.

OC 2.2.1.2 The responsibilities for the assessment of the **TTC/NTC** fall on **Grid Operators**. According to **National Grid Codes** or based on national regulatory frameworks, **Grid Operators** are bound to operate the **Grid**, always respecting **Security of Operation (SoO)**, while monitoring the condition of their **Grid** and managing congestion.

OC 2.2.1.3 A **Grid Operator** may request the **SMO** to perform the calculation of the **TTC/NTC** on its behalf through a dedicated service contract but the responsibility of the assessment of the **TTC/NTC** still lies with the **Grid Operator**. Accordingly, the **Grid Operator** shall respect the related procedures defined by the **SMO** as per OC 2.1.2.

OC 2.2.1.4 Therefore, the subsidiarity principle is applied in steps during the **TTC/NTC** assessment process.

OC 2.2.1.5 Each concerned **Grid Operator** is thus responsible for the provision to neighbouring **Grid Operators** and to the **SMO**, the following necessary input data for the load flow calculations for its **Grid**:

- a) Relevant **Grid Model** and topology.
- b) Technical data of the **Grid**.
- c) Estimated **Generation** and **Demand** profiles.
- d) Technical and Operational limits.

OC 2.2.1.6 The capacity assessments shall be based on common sets of data to form a commonly agreed **Base Case**.

OC 2.2.1.7 The annual **NTC** calculations are part of the annual schedule. For this purpose, at least four (4) values of **NTC** for import and four (4) values for export across each border shall initially be calculated, considering the planned availability of the **Transmission System**: peak and off-peak hour values in period for dry season (or other period to be agreed on) and peak and off-peak hour values in rainy season (or other period to be agreed on). The frequency of calculation of the **NTC** shall increase from semi-annual (i.e., dry season and rainy season) up to its final target of every hour, according to a programme to be agreed from time to time by the **Grid Operators** and the **SMO** based on the economic viability of the frequency of calculation and established in the **Operational Procedures**.

OC 2.2.1.8 Additional **Snapshots** of load flow situations may be provided if requested. The **SMO** shall provide interconnected **Network Base Cases** for these additional **Snapshots**, according to the relevant **Operational Procedures**.

OC 2.2.1.9 The **Grid Operators** and the **SMO** shall treat all data as confidential. The assessment procedure shall guarantee that each **NTC** value is achievable without compromising the security of the **WAPP Power System**.

OC 2.2.1.10 The **TTC/NTC** are calculated for each pair of electrically adjacent countries. In case of strong interdependencies among different groups of **Control Areas**, calculation of **TTC/NTC** between these **Control Areas** and the neighbouring countries shall be performed under the coordination of the **SMO**, through dedicated **Operational Procedures**, by considering the adjacent **Control Areas** as a whole.

OC 2.2.2 **Base Case Construction**

OC 2.2.2.1 The set of data constituting a **Base Case** includes a **Common Grid Model** and input data describing **Demand** and **Generation** profiles forecast, along with **Network** topology for the study time frame (year, month, week, and day).

OC 2.2.2.2 The **SMO** shall provide **Operational Procedures** for the harmonization of the **Grid Operators'** inputs to set up the common data sets efficiently.

OC 2.2.3 **Grid Model**

OC 2.2.3.1 The **Grid Model** should contain, as much as possible, a full representation of the **Elements** of the **Grid** of each **Member State**. The study area shall cover at least all the representative nodes of the **Relevant Grid**, and it shall provide an accurate understanding of the distribution of physical flows on **Cross-Border Interconnections** to identify potential loop flows phenomena.

OC 2.2.3.2 The effect of **HVDC Systems** between areas is represented through injection or sinks at the relevant nodes, and by using an appropriate computation model that reflects the static and dynamic behaviour of the **Facilities**.

OC 2.2.3.3 The study area for **NTC** assessment between two neighbouring **Interconnected Member States** will be determined case by case following the above principles and could involve just a subset of the full **Common Grid Model**. Each party can ask for an extension of the study area if necessary.

OC 2.2.3.4 Load flow calculation shall be performed using an **Alternating Current (AC)** load flow model. Dynamic stability studies could be additionally performed to verify the violation detected in the steady state computation, also according to the operational experiences.

OC 2.2.4 **Input Data**

OC 2.2.4.1 **TTC/NTC** assessment for each time frame being considered requires the following:

- a) The thermal ratings of the **Elements** of the **Transmission System** as well as the electrical parameters. Thermal rating shall be specified in Amps and in MW, considering a predefined power factor and nominal voltage. Depending on the time frame studied, the corresponding seasonal values of thermal ratings shall be used.
- b) The maximum and minimum active and reactive power output for the **Generation Facilities'** units included in the **Grid Model**.
- c) The expected **Grid** topology at the time frame considered.

- d) The **Generation** profile by the means of the injection at each node at the time frame considered.
- e) The **Load** profile by the means of the net sink at each node at the time frame considered.
- f) The common set of programs of cross-border electricity exchanges and the net balances of each **Grid Operator's Control Area** at the time frame considered.
- g) The common set of cross-border electricity exchanges considered in the **Base Case** relates to the best forecast for the cross-border electricity exchange at the time frame considered.
- h) The expected maximum power **Generation** available at the time frame considered.
- i) The **Generation Shift Key (GSK)** to adopt for the time frame considered. The **GSK** helps to obtain a list specifying those **Generation Units** to which to assign an increase or a decrease.

OC 2.2.4.2 Each **Grid Operator** commits itself to provide the best estimated available input data for its own **Control Area**, reflecting as much as possible realistic **Scenarios**, previously agreed within its country or with reference to the historical data,

OC 2.2.4.3 A **Base Case** can be developed for:

- a) Real observed operation situations.
- b) Forecast conditions.

OC 2.2.4.4 While the real observed operation situations offer a true **Scenario** of the behaviour of each **Power System**, forecast conditions can sometimes provide a better baseline because it would take into account the expertise of each **Grid Operator** regarding the expected behaviour of **Generation** and **Load** in its own country and knowledge of the scheduled maintenance works on the **Grid Elements** and the **Facilities**. These two (2) alternative approaches on **Base Case** construction could also be combined. The **Base Case** would be starting from a real observed situation (**Snapshot** of the **Power System** at selected **Scenarios**) then modified by each **Grid Operator** with updated **Information** regarding its **Power System** considering foreseeable differences due to the:

- a) **Load** profile, according to the **Demand Forecasts** over the time frame being analysed;
- b) **Generation** profile based on forecasts of primary energy sources (e.g. hydro reserves, fuel availability); and
- c) **Grid** configuration and planned **Generation** or **Forced Outages** (long lasting).

OC 2.2.4.5 The **SMO** shall establish **Operational Procedures** to perform these tasks in accordance with **Good Utility Practice**. The procedure that each **Grid Operator** uses to modify the starting **Base Case** must utilize modifications that are consistent with real **Generation** limits/possibilities and the cross-border electricity exchanges on the interconnection tie-line. Each **Grid Operator** must explain the nature and extent of any modification performed on starting **Base Case** and shall communicate the rationale when sending such modification to other **Parties**.

OC 2.2.5 **Guidelines for Load Flow Calculation**

- OC 2.2.5.1 In order to determine the cross-border transaction limit between two (2) neighbouring **Interconnected Member States**, cross-border electricity exchanges are gradually increased while maintaining the **Load** in the whole system unchanged until security limits are reached.
- OC 2.2.5.2 Starting from common **Base Case**, the additional cross-border electricity exchange is performed through an increase of **Generation** on the exporting side and an equivalent decrease of **Generation** on the importing side. This **Generation** shift is to be made stepwise until violations in **Operation Security Standards** are detected in **Security Assessment**
- OC 2.2.5.3 The **Generation** increase/decrease shall be performed according to some predefined criteria. The general criteria as well as any exceptions are to be defined by the **Grid Operators** involved in the calculation of a given **TTC/NTC**. A possible way to distribute **Generation** increase/decrease in a given **Power System** of a **Member State** over the different generating sets include the Increase/decrease according to a well-known merit order: whenever economic dispatch is applied the increase/decrease of **Generation** shall be applied according to the merit order.
- OC 2.2.5.4 The shift is to be performed considering the technical operation constraints of each **Generation Unit** and its technical limits (maximum/minimum power, optimal use of a power plant, water, or fuel available).
- OC 2.2.5.5 The choice among different shift possibilities or even a combination of shifting strategies is left to the responsibility of each **Grid Operator** but shall be explained and communicated to the other **Grid Operators** involved in computing a given **TTC/NTC**.
- OC 2.2.5.6 The **Party** who is making the calculation is responsible at a minimum for the **Contingency** analysis in its **Transmission System** and cross-border tie lines including some well-known **Contingencies** in the neighbouring **Power System** which influence the security of its own **Power System**.
- OC 2.2.5.7 The cross-border electricity exchange increase/decrease goes on until security rules are violated– by considering all the **Contingencies** on the **Contingency List** (OC 3.3) one at a time – in the **Grid** and the interconnection tie-lines of the **Grid Operator** performing the calculation, or inside another **Power System** of a **Member State** with respect to thermal ratings of elements of the **Transmission System**. Security problems can result in thermal, voltage, stability limitations that are to be defined by the **Grid Operator** which performs the calculation and shall be coherent with the rules **Published** in its **National Grid Code**. The **SMO** shall coordinate the process of running the calculation and support the **Grid Operators** to solve security problems according to the **Operational Procedures** adopted by **WAPP** and approved by **ERERA**.
- OC 2.2.5.8 Where the violation occurs within the country that runs the calculation, the **Grid Operator** which performs the calculation shall first determine if the congestion could be relieved by any **Remedial Action** without reducing the security level of the **Power System**. Where the constraint remains, then the security limit becomes effective. Otherwise, the simulation of the cross-border electricity exchange increase/decrease can proceed.

OC 2.2.5.9 Where the violation occurs in another **Power System** of a **Member State**, its impact shall be confirmed by the **Grid Operator** of the **Grid** where the congestion takes place, before the limit is considered as effective. Thus, the **Grid Operator** running the calculation shall:

- a) Notify the **Grid Operator** of the **Grid** where the congestion takes place.
- b) Discuss the physical reality of this constraint.
- c) Consider the constraint in the security analysis only if the involved **Grid Operator** concurs.

OC 2.2.5.10 Therefore, obtaining an **NTC** value limited by a security constraint within another **Grid Operator's Grid** constitute an implicit agreement with the other **Grid Operator** on the reality of this constraint. Once all constraints are recognized by both the neighbouring **Grid Operators**, they shall be considered binding.

OC 2.2.5.11 The process of increasing the electricity transfer goes on until a congestion caused by a **Contingency** cannot be cleared by any **Remedial Action** of the **Remedial Action List** of the involved neighbouring **Power Systems**. The last value of additional cross-border electricity exchange which does not involve any security problem forms the value ΔE . It represents the extra amount of power over the **Base Case** that can be exchanged continuously from one **Power System** of a **Member State** to another while ensuring the **Security of Operation (SoO)** of both interconnected **Power Systems**. This value, added to the initial transaction value (**BCE: Base Case Exchange**), gives the **Total Transfer Capacity (TTC)** between these countries and it is expressed as:

$$\text{TTC} = \text{BCE} + \Delta E = \text{NTC} + \text{TRM}$$

Where:

- a) **TRM** is the **Transmission Reliability Margin (TRM)** defined in the Article OC 2.2.6 .
- b) **NTC** is the **Net Transfer Capacity**.

OC 2.2.5.12 Where the **Generation** shift limit between the two (2) concerned **Power Systems** according to their actual available **Generation** is reached and no security rules are violated, then no realistic limitation on the **TTC/NTC** for the **Base Case** is found. In this case, the **NTC** between these two (2) **Power Systems** would equal the shift of all available **Generation**.

OC 2.2.6 **Transmission Reliability Margin (TRM)**

OC 2.2.6.1 A margin in the **Total Transfer Capacity (TTC)** must be maintained to account for the deviations occurring both in real-time operations and in the capacity assessment process.

OC 2.2.6.2 This margin refers particularly to the **Imbalances** due to the **LFC (Secondary Control)** and **Primary Control**, needs for common **Reserve**, and emergency cross-border electricity exchanges to cope with unbalance situations. These sources of uncertainty are used to calculate the **TRM** for a given direction of transfer. Each **Grid Operator** calculates its own **TRM** values according to requirements for ensuring the **Security of Operation (SoO)** of its **Grid**. The **SMO**

shall coordinate the process of the calculation according to the **Operational Procedures** adopted by **WAPP** and approved by **ERERA**.

OC 2.2.6.3 Finally, each pair of neighbouring **Interconnected Member States** should agree on a unique value of **TRM** for a given direction of transfer. In case of disagreement, each **Grid Operator** will maintain its final value of **TRM** in operations according to the need of its own **Power System** for which it is solely responsible.

OC 2.2.6.4 The **TRM** is determined by unintended **LFC** deviations and needs for **Reserve Sharing** and emergency cross-border electricity exchange.

OC 2.2.6.5 **LFC** margin (U_{LFC}) can be estimated through statistical analysis of past data using the estimated variance of deviation of historical series (σ^2) for one or more years. These time series data shall be initially filtered to avoid the bias which may be introduced by large deviations, occurring as the result of sudden **Load** imbalances (like the one induced by **Generation** trips), that must be considered in the emergency cross-border electricity exchange. Since **LFC** margin is a statistical estimate, it can be expressed in terms of the respective probability density function variance estimates, σ^2 , of the statistical data. In other words, $U_{LFC} = K \times \sigma$, with $K = 1, 2$, or 3 depending on the probability threshold considered ($K = 1$ is the lowest, while $K = 3$ is the highest).

OC 2.2.6.6 As far as **Reserve Sharing** (U_{RS}) and emergency cross-border electricity exchange (U_E) are concerned, their amount shall be evaluated and agreed by the **Grid Operators** involved.

OC 2.2.6.7 To combine margins of the uncertainties mentioned above into a **TRM** value, one of the following two rules or a combination of them may be applicable:

- a) Add the individual margins (worst case combination): **TRM** = $U_{LFC} + U_{RS} + U_E$
- b) Obtain the maximum individual uncertainty margins (i.e., assume that these events cannot happen simultaneously): **TRM** = $\max(U_{LFC}, U_{RS}, U_E)$.

OC 2.2.6.8 In any case the value of the **TRM** should be decided by each **Grid Operator** considering its regulating capacity and the interconnection **Security of Operation (SoO)**, and a minimum standard value shall be settled by the **SMO**, adopted by **WAPP**, and approved by **ERERA**.

OC 2.2.7 **Uncertainties in TTC Calculation**

OC 2.2.7.1 Uncertainties regarding the **Base Case** cross-border electricity exchange, which means uncertainties on a **Scenario** about the expected behaviour of **Market Participants**, may translate into more substantial uncertainties about **TTC/NTC**. The assessments of **TTC** and **NTC** are based on calculations that consider specific assumptions regarding the **Base Case** cross-border electricity exchange. Uncertainties in **Base Case Scenarios** may be considered when allocating **NTC** in different time frames. Separately from the assessment of the **NTC/TTC** and the calculation of the **TRM**, **Grid Operators** may decide whether additional margin shall be considered, in case of strong uncertainties in **Generation Scenarios**.

OC 2.2.7.2 In a yearly planning procedure, the uncertainties on the **Scenarios** may be quite substantial allowing only a partial allocation of **NTC** in advance. When getting closer to the operating horizon, these uncertainties may diminish such that further portions of **TTC/NTC** may

be allocated to **Market Participants**. Moreover, subsequent calculation of **TTC** and **NTC** at different time frames (yearly, weekly, day ahead) will be necessary to allocate for each condition the maximum value of **TTC**.

OC 2.2.8 ***Treatment of Different Results Among Grid Operators***

OC 2.2.8.1 The use of **Operation Security Standard (N-1 OSS)** deterministic criterion to perform the assessment of **Contingency** effects on **NTC** calculation is recommended.

OC 2.2.8.2 In the case where a **National Grid Code** and/or additional guidelines issued by national authorities or **NRAs** oblige **Grid Operators** to use different security criteria, the concerned **Grid Operators** shall apply them. Reconciling conflicts which arise from such different security criteria shall be based on the principle of subsidiarity.

OC 2.2.8.3 Before applying the **TTC** assessment procedure, each **Grid Operator** has to declare which are the security rules (security criteria and security thresholds) adopted, the worst **Outage** case that has to be taken into account in order to safeguard its own **Power System** security, and the technical constraints limiting the power shift to assess the **NTC** value for a given direction of power flow.

OC 2.2.8.4 Each **Grid Operator** is responsible for deciding on its own **Grid** topology and the way it intends to perform the **Generation** shift from its side, which shall be declared and communicated.

OC 2.2.9 ***Already Allocated Capacity and Available Transfer Capacity***

OC 2.2.9.1 During the process of allocation of the **TTC**, that covers time frames from the year ahead to the day ahead, a set of new concepts are introduced. These are the **Already Allocated Capacity (AAC)** and **Available Transfer Capacity (ATC)**.

OC 2.2.9.2 The **AAC** is the total amount of regulatory-driven allocated transmission rights for the **Grandfathered Contracts** identified by **ERERA**. The **ATC** is the part of **NTC** that remains available for other **Bilateral Contracts** of the **OTC Market** and for the **Day-Ahead Market** after the **AAC** has been accounted for. **AAC** and **ATC** are thus a result of each stage of the allocation process as per the **Market Code**.

OC 2.2.9.3 The relation between **AAC**, **NTC** and **ATC** is as follows:

$$ATC = NTC - AAC$$

OC 2.2.9.4 The following Figure OC 1 gives an overview over the **Transfer Capacity** concept.

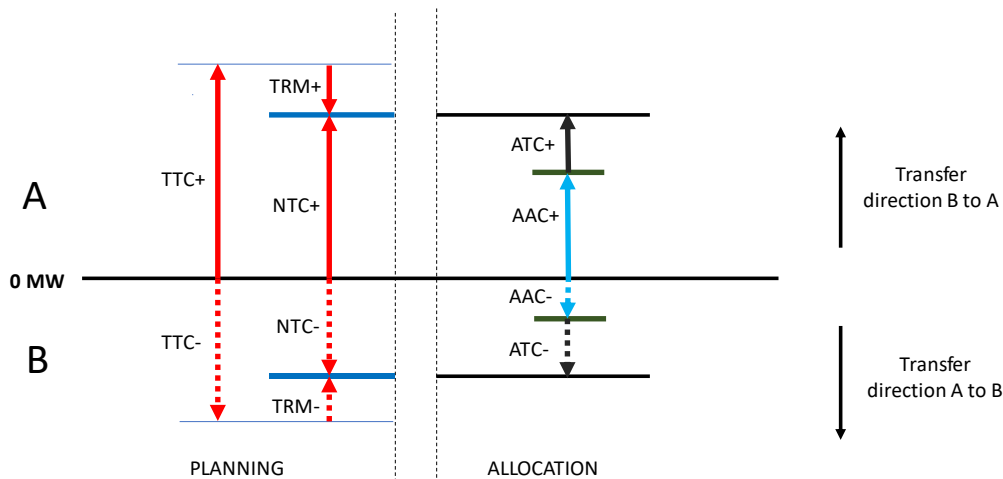


Figure OC 1. Transfer Capacity definitions.

OC 3. SECURITY OF OPERATION (SoO)

OC 3.1 Operational Limits

OC 3.1.1 **Operational Limits** can be determined by the physical characteristics of each **Element** (loading limits) or by the conditions of the **Power System**, if more stringent than the previous ones. **Operational Limits** can be permanent or temporary, and both can vary with the season. For the **Elements** that do not belong to the **Relevant Grid**, **Grid Operators** shall keep updated, their inventory and characteristics. For the **Elements** that belong to the **Relevant Grid**, their characteristics have to be shared among the neighbouring **Grid Operators**.

OC 3.1.2 Operating ranges for **Generation Facilities**, **HVDC Systems**, and **Demand Facilities** are specified in the **Connection Code**.

OC 3.2 Operation Security Standard (OSS)

OC 3.2.1 The **Operation Security Standard (OSS)** applies to the **Relevant Grid** as far as voltage and currents are concerned, and to the whole **Synchronous Area** as far as frequency and balancing are concerned.

OC 3.2.2 A **Power System** is considered compliant with the **Operation Security Standard (OSS)** adopted in this **Operation Code** if:

- it continues to work within its permanent admissible limits of voltage, frequency and current in any part of it after the occurrence of any single **Normal Contingency** of the **Contingency List** followed by the application of the corresponding **Remedial Action**.
- between the occurrence of the **Contingency** and the application of the corresponding **Remedial Action**, the admissible permanent limits are violated but the **Operational Limits** are kept within the temporary acceptable limits for a given length of time.

OC 3.2.3 The state of functioning of the **Power System** described in article OC 3.2.2 is also called **Normal State**. In **Normal State** there is no risk for the **Cross-Border Interconnection**.

OC 3.2.4 The **Operation Security Standard (OSS)** is also called **N-1 OSS**, where N is the number of **Elements** in service. For its application, **Grid Operators** shall guarantee the **Security of Operation (SoO)** by analysing periodically the occurrence of the **Contingencies** and verifying that the **Remedial Actions** in real-time are available and effective.

OC 3.2.5 Concerning the operation of the **WAPP Interconnected Transmission System (WAPPITS)**, **Load Shedding** impacting on the **Cross-Border Interconnections** cannot be included in the **Remedial Action** list, against **Normal Contingencies**, unless **Interruptible Loads** contracts with industrial users are envisaged. Without prejudice to the applicable national electricity market regulations, cross-border electricity exchanges shall be the last to be reduced in the **Remedial Actions** list.

OC 3.2.6 In addition to the compliance with the **N-1 OSS**, **Grid Operators** shall also strive for the resilience of the **Power System** in case of occurrence of multiple **Contingencies** or **Contingencies** more severe than the ones in the **Contingency List**. For this purpose, **Grid Operators** shall design and carry out **Defence Plans** and **Restoration Plans** to be applied to counteract such events with the objective of limiting their consequences in terms of severity (MW and MWh lost) and duration of the power outages.

OC 3.2.7 **Grid Operators** shall assess the security conditions by applying measures under their control, but reflective of verifications in steady state and dynamic conditions.

OC 3.3 Contingency Analysis and Remedial Actions (Security Assessment)

OC 3.3.1 **Grid Operators** shall perform regular **Network Studies**, at least on a daily basis, to assess the consequences of both the most probable and the most complex **Contingencies** and also analyse their effects on the **Security of Operation (SoO)** of the **Power Systems** to which they are interconnected. In order to deal with the **Contingencies**, **Grid Operators** shall:

- a) Design the **Remedial Actions** (manually or automatically operated) able to neutralize or mitigate the consequences of such **Contingencies**.
- b) Adopt a **Restoration Plan** to recover the **Power Systems** from **Blackout State** or **Emergency State**.

OC 3.3.2 **Grid Operators** shall group **Contingencies** in three (3) categories: **Normal Contingencies**, **Exceptional Contingencies** and **Out of Range Contingencies**.

OC 3.3.3 The **Normal Contingencies** are **Contingencies** leading to **Imbalance** less than or equal to the **Reference Incident** in any one of the following (i) the loss of single line or double circuit line, single transformer, (ii) the loss of a single **Generation Unit**, (iii) the loss of a single **DC** link for both import and export. The **Reference Incident** represents the maximum instantaneous power deviation between **Generation** and **Demand** that could happen in the un-split **Synchronous Area**

(e.g., the loss of the largest **Generation Unit** or **Generation Fleet** connected to a single bus bar) to be handled by **Primary Control** starting from undisturbed operation. Each **Grid Operator** has the right to include the simultaneous trip of the double circuit lines (on the same tower) in the category of **Normal Contingency** on the basis of the protection and the percentage of length on the same towers. The **Normal Contingencies** are in the **Contingency List**

OC 3.3.4 The **Exceptional Contingencies** are **Contingencies** involving the loss of more than one **Element** due to a common cause (e.g. a fault between a **Current Transformer** and a Circuit Breaker triggering the breaker failure protection, loss of a bus bar).

OC 3.3.5 The **Out-of-Range Contingencies** are **Contingencies** involving the simultaneous occurrence of more **Contingencies** even without functional common causes (e.g. caused by exceptional weather conditions) followed by loss of **Generation**, **Load** and other major catastrophic consequences. The **Out-of-Range Contingencies** are also those **Contingencies** whose effect exceeds the capability of the system to withstand.

OC 3.3.6 For each **Contingency**, the relevant **Grid Operator** shall study the most effective countermeasures that manually or automatically manages it, to apply in real-time in order to avoid the **Power System** to work outside of its **Operational Limits** in case of **Normal Contingencies** or to avoid spreading the negative consequences of the blackout in case of **Exceptional** or **Out of Range Contingencies**.

OC 3.3.7 The relevant **Grid Operator** shall group the **Remedial Actions** corresponding to each **Normal Contingency**. Such countermeasures shall fulfil the **OSS** and shall be agreed with the adjacent **Grid Operators** if involved in their actuation or relevant for the **Transfer Capacity** across the borders. **Normal Contingencies** and related **Remedial Actions** are simulated for the calculation of the maximum **Transfer Capacity** across the borders.

OC 3.3.8 **Grid Operators** shall adopt **Defence Plans** to remedy, as much as possible, the negative effects of **Exceptional** and **Out of Range Contingencies**. **Defence Plans** shall deploy **Load Shedding** techniques for balancing the **Power System** in **Emergency State** operation (frequency disturbance and/or voltage collapse) and minimizing the frequency and duration of the power **Outage**. Most significant **Exceptional Contingencies** shall be used in the **Dynamic Security Assessment (DSA)** to assess the response of the **Defence Plans** against such stresses. **Out of Range Contingencies** are used to evaluate possible extreme disaster **Scenarios**.

OC 3.3.9 Notwithstanding the right of each **Grid Operator** to decide what is the best **Operation** rules for its **Power System**, transparent and technically consistent criteria for **Security Assessment** and adopted tools shall be shared, at least, at **Synchronous Area** or **Regional** level. Even if different, they shall be declared and technically discussed.

OC 3.4 System States

OC 3.4.1 In this OC 3.4, the *de facto* standard rank² of **System States** (or **Operating Conditions**) is indicated together with the associated definition, identification (which depends on security considerations), special powers given to the **Grid Operators**, inter-**Grid Operators** cooperation and actions to bring the **Power System** back to a secure **System State**. In this standard rank, the system parameters can vary within each **System State**, and the range of variation in each **System State** could be defined and harmonized by the **Grid Operators**, as per OC 3.4.9.

OC 3.4.2 The **Normal State** is the state of functioning of the **Power System** described in OC3.2.2.

OC 3.4.3 The **Alert State** is the **System State** in which, the interconnected **Power System** is still within acceptable limits, but no **Remedial Action** is available to cope with a **Contingency** of the **Contingency List**. Reasons could be forecast errors or lack of unexpected unavailability of a **Remedial Action**. The affected **Grid Operator** shall timely warn all the **Grid Operators** of the **Interconnected Member States** and the **SMO** about the results of the **Security Assessment** (see OC 1.5.1.4 and OC 3.3 for details) if a **Contingency** in its **Control Area** could cause cascading **Outages** in the neighbouring **Control Areas**.

The identification of the **Alert State** is possible on the basis of the **N-1 OSS** simulations that should show if one or more **Contingencies** of the **Contingency List** could affect the **Cross-Border Interconnection**. The **SMO** monitors the **WAPP Power System** and may interact with **Grid Operators** to support the management of the system.

OC 3.4.4 The **Emergency State** is the state in which the interconnected **Power System** has deteriorated to various levels of severity, because the **Operational Limits** are no more fulfilled and/or **Grid** splits or power cuts could be in progress. In this **System State**, regardless of the location of the deterioration, the risk for the **Power Systems** of **Interconnected Member States** is considered to be high as well as the propagation of the **Contingency**. In this state, **OSSs** cannot be fulfilled by the affected **Grid Operator** and ordinary **Remedial Actions** would be ineffective. Reasons for the **Emergency State** could be forecast errors, **Exceptional Contingencies**, **Out-of-Range Contingencies** and malfunctioning of protections.

The affected **Grid Operator** shall warn and continuously update the **SMO** and the **Grid Operators** of the **Region** and request for support.

The identification of the **Emergency State** is the observation, in the **SCADA**, of the phenomena that characterize the **Emergency State** itself and the evaluations of the **Contingencies**.

OC 3.4.5 In **Emergency State** the affected **Grid Operator** is responsible for the fast application of the **Defence Plans**, the communication with the **SMO** and the neighbouring **Grid Operators** but the guarantee to respect the **Operational Limits** is suspended.

OC 3.4.6 The **Emergency State** includes the **Blackout State** and the **Restoration**.

² Classification commonly used in Europe (UCTE and ENTSO-E) and in Cigré.

- OC 3.4.7 The **Blackout State** is characterized by the absence of voltage in many buses of the **Grid** of a **Control Area**, or the loss of a large percentage of **Load** in the concerned **Control Area**. Reasons for the **Blackout State** could be **Exceptional Contingencies** or **Out-of-Range Contingencies** followed by the failure of the **Defence Plans**. Human errors and combinations of more than a cause could be the root causes of a blackout. The blackout can be wide, but in any case, the risk for the **Cross-Border Interconnection**, if still intact, is high. **Grid Operators** of a **Synchronous Area** shall agree on the conventional identification of blackout in terms of extension and maximum time to identify it. It is recommended to make a distinction between an ordinary power **Outage** (local and controllable) and a blackout, characterized by the total absence of voltage in large areas of the **Power System** of a **Member State**, involving the **WAPPITS** and lasting more than five (5) minutes. In case of blackout and under request of the affected **Grid Operator**, the **Restoration Plan** is triggered, and the neighbouring **Grid Operators** shall cooperate to the re-energization, using top-down and bottom-up **Restoration** strategies. Safety rules are unbreakable, and the suspension of market activities shall be regulated by special **Contingency** procedures.
- OC 3.4.8 The **Restoration** is a transition phase from **Blackout State** back to **Normal State**. It consists of the series of operations coordinated by the **Grid Operators** and the **SMO** aimed at reenergizing the **Grid** and synchronizing **Islands** to provide electricity and to satisfy the **Demand**.
- OC 3.4.9 Upon coordination within the **WG2** and consequent approval by **ERERA**, the **Grid Operators** may define and propose harmonized ranges of values within which **Power System** parameters (e.g., frequency and voltages) can vary for each **System State**. These values do not represent the necessary conditions to identify a **System State** (which depends on security considerations, as per articles above), but they have an informative purpose towards **Grid Users** that seek access to the **WAPP Interconnected Transmission System**.

OC 3.5 Stability Studies

- OC 3.5.1 Regular **Security Assessments** are **Network Studies** performed in steady state condition by means of **AC** load flow calculation. This is considered acceptable in **Good Utility Practices** as long as the permanent limits are more stringent than the transient limits and the transient limits are not exceeded before the activation of the **Remedial Actions**. If not, the acceptable transient limits shall be reduced by the **Grid Operator**.
- OC 3.5.2 Stability studies shall include transient stability, dynamic stability and voltage collapse. **Grid Operators** and the **SMO** shall conduct such **Network Studies** periodically. The methodology to set up dynamic **Common Grid Models** should be ready in two (2) years after the date of entering into force of this **Operation Code**. The frequency of **Dynamic Security Assessment (DSA)** shall be agreed from time to time by the **Grid Operators** and the **SMO** based on the economic viability of the calculation.
- OC 3.5.3 **Grid Operators** shall perform stability studies to assess the security of the system beyond the normal events, and:

- a) to design **Defence Plans**, in case of **Contingencies** more severe than the ones of the **Contingency List**.
- b) to verify the need for, or the sufficiency of the amount of **Load Shedding**.
- c) to cope with multiple **Contingencies**.
- d) To prevent collapses in the cases where the inertia is considered scarce and / or the transmission distances increase due to the displacement of **Generation** with respect to the **Loads**.

OC 3.5.4 The **SMO** shall support **Grid Operators** in the harmonization and update of their **Defence Plans**.

OC 3.6 Voltage Control and Reactive Power at the Borders

OC 3.6.1 Voltage at the busses of the interconnected **Relevant Grid** shall be regulated within the range of rated voltages to be defined by the **SMO** and adopted by **WAPP** in order to harmonize these rated voltages in the region.

OC 3.6.2 Neighbouring **Grid Operators** shall limit the reactive power flows across the borders to avoid potential reduction of **NTC** due to poor power factor. In **Normal State**, the reactive power flow exchanged on the interconnector should be close to zero. The **Grid Operators** shall use the voltage regulation resources to achieve this target.

OC 3.6.3 In case of adoption of phase shift transformers in the **Relevant Grid**, the tap position of the transformer shall be agreed among the **Grid Operators** and its use as **Remedial Action** shall be indicated.

OC 4. NETWORK PROTECTION AND DEFENCE PLANS

OC 4.1 General Principle

OC 4.1.1 This **Operation Code** prescribes the minimum requirements for the protection system and assign the responsibility of their enforcement to the **Grid Operators**.

OC 4.1.2 Each **Grid Operator** shall conform to the same protection standards as far as the **WAPPITS** is concerned and should transfer the obligations relating to such protection standards to their **Grid Users**. **Grid Operators** of **Interconnected Member States** shall conclude for each tie line an **Interconnection Agreement** regulating, among others, the management of the protection system.

OC 4.2 Fault Protection

- OC 4.2.1 Fault clearing time shall be the minimum between the requirements prescribed in the **National Grid Codes** of the **Grid Operators** of a **Synchronous Area**. **Grid Operators** shall specify the clearing time for each voltage level of their **Grid**. The protection systems set by the **Grid Operators** shall guarantee the shorter operation times than the clearing time, including in the case of circuit breaker failure.
- OC 4.2.2 Selectivity of fault protection mechanisms must be guaranteed. Bus bar and breaker failure protections shall be installed at the sending and receiving substations of each tie line.
- OC 4.2.3 Redundancy shall be prescribed by back up or *main 1, main 2* at local level and remotely to cope with failures of any **Element** in the chain of the local protection system. An intentional time delay of 300 - 500 milliseconds shall be granted to guarantee the best possible selectivity.
- OC 4.2.4 Automatic reclosing functions are recommended. Agreements on automatic reclosing functions shall be made on a case-by-case basis and reported in the **Interconnection Agreement** considering the number of shots, poles (three or single pole) and their adoption close to **Generation Units**³, pursuant to respective **National Grid Codes**.
- OC 4.2.5 The **Relevant Grid** shall be at the same protection standard level adopted for the tie lines.

OC 4.3 Defence Plans Coordination

- OC 4.3.1 The **Defence Plans** are defined as those control actions dedicated to limit the consequences of major disturbances whose severity goes beyond the **Normal Contingencies** of the **Contingency List**. **Grid Operators** are responsible for the design, control and application of the **Defence Plans** in their **Control Area**. In particular, no one besides the relevant **Grid Operator** shall be allowed to order the **Restoration** after **Defence Plan** activation.
- OC 4.3.2 No use of **Defence Plans** other than those listed above shall be allowed (e.g. for increasing cross border **Transfer Capacity**).
- OC 4.3.3 The necessity for the coordination of **Defence Plans** lies on the fact that:
- a) their operation creates unbalances that could negatively affect the operation of the **Power System** of one or more Interconnected **Grid Operators** in the same **Synchronous Area**;
 - b) it might be necessary to equip the tie lines with special devices that have to be previously authorized and agreed in terms of line opening policies;
 - c) by virtue of the solidarity principle, the **Load Shedding** sensitive to the frequency should be shared among the **Grid Operators** of a given **Synchronous Area**. Reference

³ Simulations of the effects of the reclosing (3 phases) to **Generating Units** shall be carried out.

values for **Load Shedding** are reported in ANNEX A –FREQUENCY CONTROL REFERENCE VALUES, which shall be updated by the **SMO** and adopted by **WAPP** from time to time based on the results of appropriate studies carried out by the relevant **Working Group**.

- d) All **Grid Operators** of a **Synchronous Area** shall be informed of the potential effects of the **Defence Plans** in other systems as well.

OC 4.3.4 According to the principle that no **Grid Operator** shall cause damage to another **Grid Operator**, some of the following prescriptions are intended to protect the **Cross-Border Interconnection** from maloperation.

OC 4.3.5 In the **Security Assessment** applications, the **Defence Plans** shall be simulated to assess their effectiveness to limit the consequences of **Exceptional Contingencies** and **Out of Range Contingencies**.

OC 4.3.6 In case of lack of available resources for the **Defence Plans**, if simulations show their ineffectiveness in daily operation of **Grid Operators**, then the **Grid Operators** are required to inform other **Grid Operators** of the **Synchronous Area** and are allowed to take measures, including the reduction of the Cross-Border electricity exchanges.

OC 4.3.7 Any system dedicated to the protection of the **WAPP Power System** has to be verified in adequacy and tested every one (1) to three (3) years. The guidelines and **Operational Procedures** of testing **Defence Plan** have to be coordinated by the **SMO**, adopted by **WAPP**, and approved by **ERERA**.

OC 4.3.8 The **Defence Plans** shall include the following:

- a) **Wide Area Protection Systems (WAPS)** to control overload of lines.
- b) **Underfrequency Load Shedding (UFLS)** the **Load** shed by frequency deviations.
- c) **Under Voltage Load Shedding (UVLS)** the **Load** shed by voltages in conditions close to voltage collapse.
- d) **Power System Stabilizer (PSS)** to damp dynamic stability problems.
- e) Manual **Load Shedding**.
- f) **Islanding** to segregate healthy portions from the rest of the **Power Systems**.

OC 4.3.9 **Wide Area Protection Systems (WAPS)**

OC 4.3.9.1 **WAPS** are automatic control schemes triggered by specific **Contingencies** and acting directly on the topology of the **Grid** or on the **Load** or on the **Generation** separately or in combination.

OC 4.3.9.2 **WAPS** are permitted, if they are designed and operated, under strict requirements of dependability (availability when needed) and security (operation only when needed).

OC 4.3.9.3 Coordinated **WAPS** between neighbouring **Grid Operators** shall be permitted if they are operated with the goal of safeguarding the integrity of **Cross-Border Interconnections** against **Exceptional** or **Out of Range Contingencies**. A typical case is the curtailment of **Interruptible Load** to avoid a line trip due to overload.

OC 4.3.9.4 Given the devastating effect that a wrong operation of the **WAPS** could have, **Grid Operators** shall:

- a) apply strict procedures to monitor and authorize the status of on / off of a **WAPS** in the **SCADA**.
- b) adopt warnings in the substations, on board of the cubicle where **WAPS** are installed and the circuitry.

OC 4.3.9.5 If the effects of a **WAPS** modify the cross-border electricity exchanges, its scheme shall be coordinated with the **LFC** and agreed upon among all the **Grid Operators** of the same **Synchronous Area**.

OC 4.3.9.6 Events in a **Power System** of a **Member State** triggering the operation of **WAPS** shall not lead to **Load Shedding** or run-back **Generation** in a **Power System** of another **Grid Operator** (or cause **Imbalances**) unless specific and clear agreements are signed.

OC 4.3.9.7 The position of circuit breakers and switches shall be made visible and made available remotely on request to the neighbouring **Grid Operators** that wants to interact with a **WAPS** in the topology of the **Grid** of the **Interconnected Member States**. In this case, the maintenance control and precautions to avoid unauthorised operation of the **WAPS**, shall be guaranteed and dedicated agreements shall be signed and attached to the **Interconnection Agreement**.

OC 4.3.9.8 Responsibility for operation of the **WAPS** shall remain on the **Grid Operator** who designs, proposes, and manages the **WAPS** within its operational area.

OC 4.3.9.9 The actions on the **Generation Units** can be of run-back type or tripping type. In both cases the reaction times of the **Generation Units** have to refer to the **Interconnection Agreement** between **Grid Operator** and the **Generation Facility Owner**.

OC 4.3.9.10 **WAPS** schemes shall be confidential but shared among the **Grid Operators** and the **SMO** for correct dynamic simulations.

OC 4.3.10 ***Underfrequency Load Shedding (UfLS)***

OC 4.3.10.1 Frequency thresholds to be set on the frequency relays shall be within the limits of frequency agreed and implemented by the **Grid Operators** of the same **Synchronous Area**. The total amount of **Load** available for shedding shall be distributed over a number of steps with the aim to contain the frequency decay without causing overshooting. ANNEX A –FREQUENCY CONTROL REFERENCE VALUES provides Reference values to be periodically revised by the **SMO** and adopted by **WAPP** based on the results of appropriate studies carried out by the relevant **Working Group**. Energy storage **Facilities** can be shed before reaching the first frequency limit.

OC 4.3.10.2 **UfLS** shall be implemented in the following order: energy storage first (hydro pumping power plants, chemical batteries power plants), then **Interruptible Load**, industrial **Load** and residential **Load** last. Nevertheless, other sequence may be implemented on country basis according to the relevant **National Grid Code**.

OC 4.3.10.3 The essential facilities like hospitals, civil and military protection facilities, as better defined by national public authorities, shall not be subject to **UfLS**.

OC 4.3.10.4 At least 50-60% of the peak **Load** shall be available for **UfLS**, including the quota for internal national needs, unless overvoltage problems arise. The Load dedicated to coordinated **Defence Plans** of a **Synchronous Area** should be at least between 40 and 50% of the peak **Load**.

The total amount of such **Load** shall be distributed almost uniformly among the steps, without prejudice to more accurate studies, jointly performed at **Synchronous Area** level.

OC 4.3.10.5 In sizing and designing the **UfLS** plan, probable system splits have to be taken into consideration as events to cope with.

OC 4.3.10.6 The share of **Load** available to be shed for frequency decays should be proportional to the peak **Load** of the **Member State**.

OC 4.3.10.7 Frequency thresholds are defined within the same **Synchronous Area** according to the dynamic studies referred to relevant **WAPP Power System** conditions defined by **WAPP**. Possible adjustments may affect the **Power Systems** of some **Grid Operators** according to the inertia of each area and the splits of **Grid** considered.

OC 4.3.10.8 **UfLS** plans shall be revised:

- a) when new **Grids** are connected to a **Synchronous Area**, or two or more **Synchronous Areas** merge; and,
- b) from one (1) to three (3) years, based on the development of each **Power System**.

OC 4.3.10.9 The **UfLS Plan** shall be designed taking into account priorities of **Load** to be shed (e.g., storage first) and objectives. **UfLS** plan reference values to be periodically revised and agreed are given in ANNEX A –FREQUENCY CONTROL REFERENCE VALUES. Values refer to 50 Hz nominal frequency.

OC 4.3.10.10 **UfLS** has to be selective. For this purpose the **UfLS** relay shall open the medium voltage feeders. The design of the **UfLS** should avoid shedding **Load** mixed with **Distributed Generation**. **UfLS** should never shed feeders essential for the auxiliary service of power plants and substations.

OC 4.3.10.11 **UfLS** should include the coordination of the reactive compensation facilities to avoid overvoltage due to the sudden drop of **Load** in the **Grid** or to avoid false operations when the voltages are too low. The coordination of the reactive compensation facilities shall be checked by the **Grid Operators** and the **SMO** considering the type of relays and the site where they are installed. ANNEX A –FREQUENCY CONTROL REFERENCE VALUES gives reference values to be periodically revised and agreed.

OC 4.3.10.12 The **UfLS** plan shall be implemented – under the responsibility of the relevant **Grid Operator**, by combining the frequency thresholds and the rate of frequency decay in order to set the **UfLS** relays to ensure fast containment of the frequency decay.

OC 4.3.11 ***Under Voltage Load Shedding (UVLS)***

OC 4.3.11.1 **UVLS** can be applied at the borders to prevent the separation of the **Cross-Border Interconnection** or to prevent voltage instability. **Grid Operators** adopting or having the intention to adopt **UVLS** for this purpose shall inform the neighbouring **Grid Operators**. **UVLS** shall not operate for voltages greater or equal to 90 % of nominal voltages.

OC 4.3.12 ***Power System Stabilizers (PSS)***

OC 4.3.12.1 **PSSs** are part of the **Defence Plans** for damping low frequency oscillations. All the involved **Grid Operators** shall carry out simulations to re-tune the settings periodically or before a new **Grid** is added to a **Synchronous Area** or two **Synchronous Areas** are merged.

OC 4.3.12.2 For this purpose, **WG2** shall promote ad hoc campaigns, evaluate the needed time and scope a dedicated procedure to accomplish the revision task. The procedure shall take into account the time needed to involve the **Grid Operators'** organization and perform the technical work of revising settings.

OC 4.3.12.3 In case of poorly damped low frequency oscillations in a **Synchronous Area**, **Grid Operators** shall immediately call for actions within **WG2** in order to propose corrective measures.

OC 4.3.13 ***Islanding***

OC 4.3.13.1 **Islanding** is the controlled separation of an area from the rest of the interconnected **Power System**. This kind of **Defence Plan** shall be the last resort for protecting the **Power System** against total blackout. If applied, this **Defence Plan** requires having resources ready to re-energize, as soon as possible, the separated area of the interconnected **Power System**.

OC 4.3.13.2 The following minimum requirements should be guaranteed for **Islanding**:

- a) Its trigger and its operation shall be automatic
- b) The detection of the conditions of **Islanding** has to be reliable (e.g. out of step relays) and shared in **WG2**.
- c) The portion of the **Power System** to be islanded shall not be across any segment of a **Cross-border Interconnection**. Separation points shall be at the connection nodes of the cross-border linking **Element** with the rest of the **Power System**.
- d) The nodes where to isolate the **Island** shall be well defined and stable from the topological point of view (e.g. stretched systems are more adapting to **Islanding** than the meshed ones due to the number of circuit breakers to be controlled and open).
- e) The **Island** shall be robust and in average well balanced (neither large surplus nor large deficits).

- f) The **Generation Facilities** of the **Island** shall have a high capability of regulating frequency and voltage.

OC 4.3.13.3 The protection scheme triggering the **Islanding** procedure and the capabilities of regulating provided by the **Generation Facilities** shall be periodically tested.

OC 4.3.13.4 **Grid Operators** having **Islanding** strategies shall inform the rest of the **Grid Operators** about the possible maximum unbalance that could result from the isolation of the **Island**.

OC 4.4 Manual Load Shedding

OC 4.4.1 **Grid Operators** shall have a manual **Load Shedding** plan which can be operated remotely. The manual **Load Shedding** may overlap with the **UfLS** plan. At least 90 % of the total peak **Load** shall be subject to possible manual or automatic **Load Shedding**.

Manual **Load Shedding** practice can complement the automatic **Defence Plans** in:

- a) balancing the **Power System** in emergency and relief overloads.
- b) sharing the discomfort in case of power rationing lasting more than the average (see article OC 6.6.8) by rotating the power rationing.
- c) counteracting the slow (i.e., no less than fifteen (15) minutes) voltage collapse phenomena.

OC 4.5 Restoration Plans

OC 4.5.1 Each **Grid Operator** member of a **Synchronous Area** is required to have **Restoration Plans**.

OC 4.5.2 The **Restoration Plan** shall be:

- a) described in detail in classified documents.
- b) with clear roles assigned to each **Grid User**.
- c) with agreed terms of cooperation with the neighbouring **Grid Operators**.
- d) periodically tested, at least every two (2) years.

OC 4.5.3 Priority of the **Restoration** strategy and practices shall be to energize the bus bars and the station service **Load** of the **Generation Facilities** as fast as possible.

OC 4.5.4 The involved **Grid Operator** shall be responsible for the application of the best available tools to restore the **Power System**, giving priority to the **Restoration** procedures. The **Grid Operator** cannot guarantee the **Restoration** times, due to the inability to forecast all the combinations of the blackouts.

OC 4.5.5 In case of re-energization from a **Power System** outside the **Synchronous Area**, the **SMO** shall coordinate the synchronization according to proper **Operational Procedures**. The involved **Grid Operators**, under the coordination of the **SMO**, shall make their **Best Effort** to cooperate in the design of the **Operational Procedures**, in testing them and in executing them in case of need.

OC 5. COOPERATION IN EMERGENCY

OC 5.1 Emergency Awareness

OC 5.1.1 Alert procedures and tools shall aim at communicating **Information** on the **System State** of the **Synchronous Area** among all the **Grid Operators** of the **Interconnected Member States** and the **SMO** in a fast and secure way. For this purpose:

- a) in addition to the **Warning System**, each control room shall communicate and have access to contact lists, with names of physical operators, telephone numbers and position to contact in case of need.
- b) secure and protected communication channels (telephone, e-mail) shall be available.
- c) a hotline always active during emergencies shall be available
- d) **Grid Operators** shall make aware, preferably with formatted messages, the state of the system, the expected duration of an **Emergency State** and request for support.
- e) Each **Grid Operator** shall facilitate crisis management, at least, by avoiding those involuntary actions of one **Grid Operator** that could worsen the status of a **Power System** of another **Member State**.

OC 5.1.2 During an emergency, a crisis conference whose modalities are previously agreed, and which is tested periodically shall be opened and maintained among all the **Grid Operators** of the same **Synchronous Area** and the **SMO** until the end of the crisis.

OC 5.2 Cooperation in Emergency to Save the System

OC 5.2.1 The terms of cooperation during **Emergency**, shall first be inspired by the sense of solidarity, but the terms and limits of cooperation shall be concretely agreed in specific procedures and multilateral agreements by the **Grid Operators**. The **SMO** shall coordinate the application of the dedicated **Operational Procedures** to manage the **Emergency** conditions of the **WAPP Power System** and provide technical support to the **Grid Operators** to safeguard the system.

OC 5.2.2 In the event one or more **Grid Operators** are in the **Alert State** or **Emergency State** and their resources are no longer sufficient to face the situation, the rest of the connected **Grid Operators** and the **SMO** shall cooperate to avoid the propagation of the **Alert State** or **Emergency State** resulting from the **Contingency** to the neighbouring **Power Systems**.

OC 5.2.3 The support from the **Grid Operators** during **Emergency State** is mandatory as long as the **Grid Operators** had previously agreed, prepared and possibly tested defined actions and plans to remedy the **Emergency**.

OC 5.2.4 In addition to the commitment to keep the integrity of the **Cross-Border Interconnection** as much as possible, frequency management is crucial to contain the risk of deterioration.

OC 5.3 Cooperation in Restoration to Recover the Functionality of the System

OC 5.3.1 **Grid Operators** are obliged to cooperate with each other for the **Restoration**. The re-energization procedures shall be well prepared, agreed, and periodically tested. The **SMO** shall support the **Grid Operators** involved in the **Restoration** regarding the best re-energization strategy to implement.

OC 5.3.2 In the choice of the re-energization strategy, **Grid Operators** and the **SMO** shall consider that:

- a) The success of the top-down strategy depends on the availability of carrying capacity of the cross-border tie lines, the **Reserve** margins of the **Grid Operators** leading the **Restoration** and their capability to communicate with all **Grid Operators** involved.
- b) The success of the bottom-up approach depends on the availability of internal resources for black start, voltage and frequency regulation capability, and **Load** management ability. This strategy may involve other **Grid Operators** in the last phase of resynchronization.

OC 5.3.3 The design of the re-energization sequences shall comply with the following criteria:

- a) As far as the frequency management is concerned:
 - i. **Frequency Leaders** have to be chosen in the following two cases: Case A- *Frequency Deviation*, where the interconnected **Power System** of the **Synchronous Area** is connected and the deviation from the nominal frequency is outside ± 200 mHz for more than one minute or Case B- *Split Situation*, where there are 2 or more portions of the **Synchronous Area** split.
 - ii. The **Frequency Leaders** may be more than one if the interconnected **Power System** splits into more than two **Islands**.
 - iii. The **Frequency Leader** changes the **Secondary Control** to **Primary Control** mode, while the other **Grid Operators** freeze the **Secondary Control** and move the set points of **Generation Units** manually, under the directions of the **Frequency Leader** to quickly restore the frequency.
 - iv. In case (A), *Frequency Deviation*, the **Frequency Leader** completes the **Restoration** until the **Secondary Control** is reactivated.
 - v. The **Frequency Leader** in a **Synchronous Area** shall be chosen among the **Grid Operators** with:

- the highest k factor of the **LFC** regulator;
 - large amount of **Reserve** that it can mobilize;
 - adequate margins on the lines;
 - visibility of frequencies from the other **Grid Operators**.
- b) As far as the resynchronization of split area is concerned:
- i. In case (B) *Split Situation*, when the conditions allow it, the resynchronization of all the split areas has to be performed. This is done in a “two by two split portions” mode. For each couple of portions, a **Synchronization Leader** is selected between the two **Frequency Leaders** of the two couple of areas to be resynchronized.
 - ii. **Synchronization Leader** plays the role of coordinating the **Frequency Leaders** and have to be chosen from among the **Frequency Leaders** which:
 - have substations under their responsibility;
 - are able to have visibility of frequency and voltages from the areas to be resynchronized.
- c) The return to normal **LFC** mode is reached once:
- i. all the split areas are resynchronized,
 - ii. the **Synchronous Area** has been restored,
 - iii. the frequency is back within the nominal frequency ± 200 mHz,
 - iv. the last **Frequency Leader** gives the green light to the **Grid Operators** for the restoration of **LFC**.
 - v. the **Frequency Leader** is the last to switch to normal **LFC** in its **Power System**.

OC 6. OUTAGE PLANNING COORDINATION BUSINESS PROCESS

OC 6.1 General Requirements

OC 6.1.1 **Grid Operators** shall keep the highest attention to the forecast activities and **Outage Planning Coordination Business Process** activities to cope with the high volatility of large volumes of energies exchanged by the **Functional Operation** of the **WAPP Power System**, and to prevent and manage **Shortage** periods. For this purpose, simulations and exchange of reliable **Information** are required as well.

OC 6.1.2 Based on forecasts, **Grid Operators** are responsible for providing the resources to cover the **Demand** and assure the necessary **Ancillary Services**. **Ancillary Services** include at least **Reserves**, frequency and voltage regulation, availability of **Black Start Capability** resources and congestion management. This implies that the forecasting processes shall consider not only the

Demand coverage but also the commitment of **Generation Units** needed in parallel to guarantee the **Ancillary Services**.

OC 6.1.3 An **Outage Planning Coordination Business Process** shall be adopted by each **Grid Operator** and should include two basic components:

- a) The internal process of each **Grid Operator**, which is not required to be shared.
- b) The coordination of **Functional Operation** with all the other **Grid Operators** in the same **Synchronous Area**, which has impact on the **Relevant Grid** as per this **Operation Code**.

OC 6.1.4 Regarding article OC 6.1.3b), the **SMO** is responsible for coordinating the **Outage Planning Coordination Business Process** with each **Grid Operator**.

OC 6.1.5 The **Outage Planning Coordination Business Process** shall guide the **Grid Operators** to issue and share, as far as the **Cross-Border Interconnection** are concerned, the following:

- a) The **Demand Forecast**.
- b) The **Maintenance Plan** and the **Unavailability Coordination** of the **Elements** of the **Relevant Grid**.
- c) The **Maintenance Plan** and the **Unavailability Coordination** of the **Generation Facilities** only for the purposes of the **Adequacy** required to the **Grid Operators**.
- d) The **System Adequacy Forecast** i.e. the forecast of the ability of each **Control Area** to cover its **Demand**, including **Reserve** requirements (see OC 8, which governs the management of **LFC**, and A.1 in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES, which gives reference values to be periodically revised by the **SMO** and adopted by **WAPP** based on the results of appropriate studies carried out by the relevant **Working Group**) and the agreed cross-border electricity exchanges and the same for the whole **Synchronous Area**, considering the cross-border electricity exchanges, within the limits expressed in this OC 6.
- e) The measures to be taken to contain any **Contingency** and trips in the **Relevant Grid**.
- f) The calculation of the **NTC** values (see OC 2), including the sharing of **TRM** values.

OC 6.1.6 Some guidelines on internal processes are also given in this **Operation Code** for the sole purpose of making the results of various **Grid Operators** homogeneous and comparable.

OC 6.2 Demand Forecast

OC 6.2.1 The **Demand Forecast** is the primary input of the **Outage Planning Coordination Business Process**. All **Grid Operators** shall share the **Demand Forecast** of their **Control Area** with the **Grid Operators** of the same **Synchronous Area** according to the **Data Exchange** principles.

- OC 6.2.2 The **Demand** shall be forecast on daily, weekly and longer time horizons. **Demand Forecast** shall, at least, include maxima and minima values of energy and power.
- OC 6.2.3 Daily **Demand Forecast** shall be, at least, at hourly resolution (24 energy mean values).
- OC 6.2.4 **Grid Operators** shall perform the forecast of various forms of **Demand** for their **Control Area**:
- a) the physical **Demand**, losses included, i.e. the **Demand** to be covered by the sum of all the active power supplied by the **Generation Facilities** installed in the **Control Area** plus the cross-border electricity exchanges.
 - b) the **Demand** covered by the conventional (synchronous) **Generation**, **VRES-based Generation**, and the one covered by **Distributed Generation**.
 - c) the **Demand** covered by the market, i.e. the one covered by the **Day Ahead Market**.
- OC 6.2.5 The forecast shall be based on historical series of data, and taking into account all the variables that could influence the electricity **Demand**, from weather and climatic factors to social-economic aspects (e.g. whether it is a working day or holiday). Hence, the **Grid Operator** shall acquire power **Demand** data from the **SCADA** and store them in **Functional Operation** databases according to the form of **Demand** to be calculated.
- OC 6.2.6 The data acquired by the **SCADA** can be complemented by the ones acquired from the **Metering Equipment**, especially for the **Distributed Generation** forecast and actual values.
- OC 6.2.7 **Distributed Generation**, especially the **VRES-based** ones, can be calculated by adopting statistical correlation methods.
- OC 6.2.8 The physical **Demand Forecast** shall be made available, at least, at **Grid Operator** level and disaggregated at node level to allow for load flow simulations for security assessments, as required for agreed market or security simulations at **Synchronous Area** level.
- OC 6.2.9 In performing the functions related to security assessments, **Grid Operators** shall determine the **Ancillary Services** requirements based on their own **Demand Forecast** and **Generation** forecast.

OC 6.3 Maintenance Plan

- OC 6.3.1 Each **Grid Operator** shall guarantee the highest availability of the **Elements** of the **Relevant Grid** by applying the **Good Utility Practices** and also maintain their assets in the best condition.
- OC 6.3.2 For this purpose, each **Grid Operator** shall elaborate its own **Maintenance Plan**, i.e. the coordinated schedule of maintenance works set up to attain the required availability levels.

OC 6.3.3 The maintenance activity remains the full responsibility of **Grid Operators** that are not obliged to disclose in detail.

OC 6.3.4 The **Maintenance Plan** shall be scheduled in a coordinated **Unavailability Plan** which considers all the needs of the **Cross-Border Interconnection** (e.g. **Demand** coverage, trading).

OC 6.3.4.1 *Maintenance Management Guidelines*

OC 6.3.4.1.1 Each **Grid Operator** shall schedule any maintenance work on the **Relevant Grid** taking into consideration the following priorities, as far as possible:

- a) scheduling the maintenance activity in periods in which the cross-border electricity exchanges are statistically the lowest.
- b) pursuing the objective of the maximization of the cross-border **NTC/ATC**.
- c) minimizing the down time of the **Elements** of the **Transmission System**.
- d) avoid causing more than once, the same **Outage** or the same capacity reduction for works that can be performed in parallel at the same time.
- e) avoid causing **Planned Outages** at the borders in periods during which at least one **Interconnected Member State** is in under-capacity regime or under exceptional circumstances and has requested other **Grid Operators** of the **Interconnected Member States** for support.

OC 6.3.4.1.2 The time frames for scheduling maintenance activities shall be the preceding year (Y-1) for the annual maintenance and the preceding week (W-1) for the weekly maintenance. The **Grid Operators** provide their own **Outage** plan to the **SMO** according to the agreed **Operational Procedures**.

OC 6.3.4.2 *Types of Maintenance*

OC 6.3.4.2.1 For the purpose of this **Operation Code**, maintenance includes two categories: the **Preventive Scheduled Maintenance** and the **Corrective Maintenance**⁴.

OC 6.3.4.2.2 The **Corrective Maintenance** can be classified as:

- a) *Deferrable*, if execution of the maintenance activity can be performed at least one week later from detection of the anomalies without affecting the safety, environment, or **Security of Operation (SoO)**.
- b) *Undeferable*, if execution of the maintenance activity must be performed within the week, to avoid dangers to people, equipment or creating a fault situation.
- c) *After fault*, if a repair activity is needed immediately as a consequence of a fault.

⁴ Cf. Cigré. Technical Brochure 660

OC 6.3.4.2.3 The **Elements** of the **Relevant Grid** are subject to the coordination process for **Preventive Scheduled Maintenance**. **Corrective Maintenance** is regulated on weekly basis.

OC 6.3.4.2.4 The schedules are subject to the annual **Preventive Scheduled Maintenance** on the **Elements** of the **Relevant Grid**, coordination between-**Grid Operators**, and must be included in the yearly maintenance schedules.

OC 6.3.4.2.5 Without prejudice to the **National Grid Codes**, **Grid Operators** shall assume the same level of priorities for the **Relevant Grid** in the approval of the **Unavailability Plans** of the **Generation Facilities**.

OC 6.4Unavailability Coordination (Maintenance Requirements)

OC 6.4.1 Neighbouring **Grid Operators** are obliged to guarantee the implementation of a coordinated schedule of maintenance activities to ensure continuity of the transmission services and in compliance with the applicable national laws.

OC 6.4.2 **Grid Operators** shall:

- a) never constrain the maintenance activities in favour of services different from the electricity supply (e.g. fibre optic for public telecom service), i.e. priority shall be given to their electricity supply services.
- b) adopt efficient forecast and scheduling methods based on monitoring and historical data to enhance the efficiency of the maintenance processes.
- c) provide timely first aid support and repairs in case of failures.
- d) respect requirements for environmental sustainability.
- e) never disclose **Information** that could turn out to be discriminatory of any **Market Participant**.

OC 6.4.3 The **SMO**, upon methodology adopted by **WAPP**, shall define **KPI(s)** to be published in an electronic bulletin on a rolling basis, in order to assess the performances of the **Outage Planning Coordination Business Process** undertaken by each **Grid Operator**.

OC 6.5Unavailability Plan

OC 6.5.1 **Coordination Policies**

OC 6.5.1.1 At each Synchronous Area level, Grid Operators shall agree on their Annual Maintenance Period (AMP).

OC 6.5.1.2 The **SMO** shall coordinate the proposed **Generation** and **Relevant Grid Outages** that create unacceptable system conditions, as well as to advise the **Grid Operators** on the **Remedial Actions** to put in place in anticipation of such proposed **Outages** to ensure the reliability of the **WAPP Power System**.

OC 6.5.2 **Yearly Unavailability Planning**

- OC 6.5.2.1 Each year, four (4) months before the beginning of the **AMP**, **Grid Operators** shall submit their **Annual Unavailability Plans (AUPs)** to the **SMO** for the sake of better coordination and **Information** exchange.
- OC 6.5.2.2 An **Unavailability Plan** shall consist of the schedule of the **Outages** – regardless of the reasons – of the **Elements** of the **Relevant Grid** and the **Generation Fleet**. This schedule shall be optimized in order to cover the expected **Demand** with the associated requirements for **Reserves** and maintenance.
- OC 6.5.2.3 Each **Annual Unavailability Plan (AUP)** shall report under reasonable hypothesis on the available energy exchange, on weekly basis, if the internal resources will cover the **Demand** of each national **Power System**, guaranteeing the **Security of Supply (SoS)** without jeopardizing the **Security of Operation (SoO)**.
- OC 6.5.2.4 The **Annual Unavailability Plans (AUPs)** shall include optimized unavailability schedules of the **Generation Fleet** and **Relevant Grid** lasting more than a number of days agreed among **Grid Operators** of the **Synchronous Area**, but not longer than one (1) week. Such a schedule should coordinate the **Outages** on the **Transmission System** with the ones on the **Generation Fleet** in order not to limit inefficiently the **Adequacy** and the cross-border **TTC/NTC** (OC 2).
- OC 6.5.2.5 The **Annual Unavailability Plans (AUPs)** shall contain exhaustive **Information** on every **Outage** affecting the cross-border electricity exchanges. The **Information** shall highlight, at least, the identification of the **Elements** of the **Power System**, the nature of the **Outage**, its duration (start and end times), the amount of MW involved and the estimated reduction of the **NTC/ATC**.
- OC 6.5.2.6 **Information** on the **Generation** shall be in aggregated form, unless more detail is allowed by the **National Grid Codes** and agreed at **Regional** level. In no case shall confidentiality be breached.
- OC 6.5.2.7 The **SMO** shall collect and process the **Annual Unavailability Plans (AUPs)** and merge them as a whole, with the three-fold objective of:
- a) facilitating the **Grid Operators'** cooperation to synchronize different interventions or changing them and conducting simulations to guarantee the **Adequacy** of the **WAPP Power System**
 - b) maximizing the **NTCs** border by border (see OC 2 for **TTC/NTC** calculation) during the non-maintenance periods. The outcome of the process shall be the **Regional Annual Unavailability Plan (RAUP)**.
 - c) guaranteeing the **Security of Supply (SoS)** and **Security of Operation (SoO)**.
- OC 6.5.2.8 The **Regional Annual Unavailability Plan (RAUP)** shall be approved by **WAPP** upon the proposal by the **SMO** and **Published** in an electronic bulletin one month before the beginning of the **Annual Maintenance Plan (AMP)**.

OC 6.5.2.9 In cases where **Adequacy** is at risk, the **SMO** shall trigger an alert procedure according to OC 6.8 and article OC 6.9.5.

OC 6.5.2.10 The **Regional Annual Unavailability Plan (RAUP)** shall become the reference for the weekly plans. As such the **Grid Operator** shall not be at fault of any future change, if declared at least, three (3) months in advance.

OC 6.5.2.11 The **Regional Annual Unavailability Plan (RAUP)** shall be the basis for the final identifications of the periods of the year when the **NTC** shall be reduced without penalties for the increased costs of the **Ancillary Services**.

OC 6.5.3 **Weekly Update of the Unavailability Plan**

OC 6.5.3.1 **Grid Operators** shall update the **Unavailability Plan** weekly. Every week, “w”, the **Grid Operators** shall:

- a) include in the list, the new maintenance interventions to be carried out from $w+3$ to the end of the **Regional Annual Unavailability Plan (RAUP)**.
- b) take into consideration the changes scheduled for $w+1$ and $w+2$ of those interventions already approved.
- c) cancel the approved maintenance works, which for any reasons cannot be processed as scheduled.

OC 6.5.3.2 Every week, w , **Grid Operators** shall execute the **Corrective Maintenance** schedule by taking into consideration the works allocated during $w+1$ or $w+2$, considering the evaluations of urgency.

OC 6.5.3.3 To ensure successful execution of the **Corrective Maintenance** schedule in article OC 6.5.3.2, the **SMO** shall apply the following steps:

- a) study all **Outages** submitted to determine if any incompatibility is identified during the **Outage Planning Coordination Business Process**.
- b) propose **Remedial Actions** including **Generation** dispatch, system reconfiguration, rescheduling of lower priority **Outages** and/or other planning adjustments to mitigate these incompatibilities, if incompatibilities are identified, the **SMO**, in coordination with the **Grid Operators** concerned.
- c) make recommendations on safety taking into consideration the following:
 - i. pressure of market or continuity of supply shall never induce **Grid Operators** to infringe national safety rules and applicable **Functional Operation** practices;
 - ii. neighbouring **Grid Operators** shall agree and be engaged to respect specific procedures for authorization;
 - iii. other minimum requirements are reported in OC 14.

- d) Updated the **Regional Annual Unavailability Plan (RAUP)** and **Publish** it in the electronic bulletin, every Friday (or the working day before, in case the Friday is a holiday), by 5 p.m.

OC 6.5.4 ***Intraday Updating***

- OC 6.5.4.1 Changes in programs, delays, and urgent **Corrective Maintenance** shall be **Published** in coordination with the market operation and scheduling process. An open access **Information** repository is recommended to make all **Grid Operators** share **Information** on the status of the **Power System**.

OC 6.5.5 ***Further Requirements for Outage Planning Coordination Business Process***

- OC 6.5.5.1 The scheduling and dispatching activities involve the **Outage Planning Coordination Business Process**. The following are further requirements in the **Outage Planning Coordination Business Process**:

- a) In $w-1$, **Grid Operators** shall supply all the needed **Information** to the **SMO** to verify the adequacy and the expected load flows concerning the **WAPP Power System** for the week “ w ”. A bulletin summarizing equipment unavailability, the expected **Demand**, and the major expected issues shall be Published by the **SMO** and circulated among **Grid Operators**. A weekly videoconference at the **Regional** level is recommended to share timely actions in case of major hazards.
- b) With reference to **Day “D”**, in $D-2$ the main activity concerning the cross-border relationships is the preparation of data on **Grid** and **Generation**, to calculate the **NTC** to be allocated in $D-1$.
- c) In $D-2$, the **SMO** shall coordinate **Grid Operators** to set up the **Common Grid Model**, the confirmation of availability of the **Contingency List**, the associated **Remedial Actions**, and the **GSK** for **NTC** calculation purposes.

OC 6.6 **Adequacy Assessments**

- OC 6.6.1 The **Adequacy Assessment** is the final step of the **Outage Planning Coordination Business Process** once the **Demand Forecast**, the **Unavailability Plans**, and the **NTC** have been made available. The **SMO** shall coordinate all the processes to perform the **Adequacy Assessment** of the **WAPP Power System**.

- OC 6.6.2 **Adequacy** in each **Control Area** level is fulfilled when the **Demand** is satisfied in terms of energy and power plus adequate **Reserve** margins, with a given probability, at any hour of the period with the total resources of available internal **Generation** and import. **Adequacy** is measured in terms of **Loss of Load Probability (LOLP)** and **Loss of Load Expectation (LOLE)**. Target values in each **Synchronous Area** shall be agreed by **Grid Operators** within **WG1**.

OC 6.6.3 The **Adequacy Assessment** shall be considered a prerequisite for the strategies on reciprocal support and the **Load** curtailment preparation. Assessments are carried out at any simulation of the annual **Outage Planning Coordination Business Process**.

OC 6.6.4 The **Adequacy Assessment** shall be based on reliable data, forecast and scheduling decisions at single **Grid Operator**, **Synchronous Area**, and **Regional** levels, and will be obtained from the combination of the **Demand Forecast**, the availability of the **Generation Facilities**, the availability of the **Transmission System**, and the market conditions.

OC 6.6.5 The degree of coverage of the **Demand** can be assessed by means of:

- a) A deterministic method of analysis of the **Reserve** margins.
- b) Stochastic methodology, viz. the **Reserves** associated with the fulfilment of pre-agreed levels of risk of not meeting the **Load**.

OC 6.6.6 Ad hoc studies shall be done to support the deterministic methods establishing the relation between the amount of **Demand** plus the **Reserve** needed, and the **Generation** mix.

OC 6.6.7 Methodologies based on stochastic approach to assess **Adequacy** shall be put into operation when the needed tools become available for all **Grid Operators**, and the forecast **Adequacy Assessments** shall be based on the same definitions of the variables and comparable methodologies. The deterministic methodologies based on **Good Utility Practices** shall be used in the interim until the probabilistic tools are available.

OC 6.6.8 In case of negative results of the **Adequacy Assessment**, the **Grid Operator** may activate the rotating **Load Shedding** plan, which each **Grid Operator** shall define and agree with the relevant **Distribution System Operator (DSOs)**.

OC 6.6.9 Prior to the activation of the rotating **Load Shedding**, the **Grid Operator** shall issue warning to the affected **Distribution System Operator (DSOs)**, public authorities, media, and the affected citizens as soon as possible after the result of the **Adequacy Assessment** is confirmed, but not later than eight (8) hours before the activation of the rotating **Load Shedding**.

OC 6.7 Reserve Margins Assessment

OC 6.7.1 Reserve Sizing

OC 6.7.1.1 Each **Grid Operator** is responsible to keep under control and procure resources to cope with unavailability of the **Generation Facilities**, **Demand Forecast** errors, **VRES** uncertainties and other probable events.

OC 6.7.1.2 **Reserves** in operation are meant to be in both directions:

- a) The **Upward Reserve** is defined as the difference between maximum active power of available **Generation** minus the peak **Load** of the period. **Upward Reserves** are to be

used to balance the **Power Systems** of the **Control Area** when the forecast shows that the **Load** could be higher than the available power **Generation** or to counteract **Generation** unavailability.

- b) The **Downward Reserve** is defined as the difference between the minimum **Load** minus the sum of the technical minima of the **Generation Facilities**, used to reduce the power **Generation** when the minimum **Load** during off peak hours is expected to be lower than the minimum allowable **Generation** and to cope with overproduction of **VRES**.

OC 6.7.1.3 **Grid Operators** in addition to the regulation of the **Reserves** to cover the **Demand**, shall assess the need for **Downward Reserve** also in relation to the penetration of **VRESs** which are not dispatchable and sometimes not even possible to be curtailed, if in particular small size **VRES Generation Facilities** are spread and embedded in the **Distributed Generation**.

OC 6.7.2 *Reserves for the Interconnected Operation*

OC 6.7.2.1 **Power Systems** of **Control Areas** shall not be operated without the **Reserves** needed for regulation (**Primary Reserve** and **Secondary Reserve**) even in times of **Shortage**. Therefore, **Reserves** shall be included in the calculations of the **Demand**. In case the **Grid Operator** lacks available **Reserves**, the **Grid Operator** is justified in applying the **Load Shedding** in order to restore the needed **Reserves** for the regulation.

OC 6.7.2.2 The needed amounts of **Reserves** shall be verified during the annual planning stage.

OC 6.7.2.3 A given amount of **Cold Standby Reserve** in upward direction shall be dimensioned to replace the available **Reserve** margins to cope with prolonged unexpected unavailability of **Generation Units**.

OC 6.7.2.4 OC 8.2 and OC 8.3 give the order of magnitude of reference values of **Primary Reserve** and **Secondary Reserves**. On the **Tertiary Reserve**, unless probabilistic simulation shows different values and if the lead time is of the order of months, a margin of 10 to 15 % of the installed capacity of the **Generation Fleet** (all sources) shall be left available.

OC 6.7.2.5 When the **Tertiary Reserve** in upward direction is less than the ones needed to keep **LOLP**, **LOLE** or **Reserve** margins within the target values, the affected **Grid Operator** shall warn the **SMO** and the other **Grid Operators** for assessing countermeasures of support and mitigate the consequences of probable **Shortage** crisis. In case of **Shortage** and without prejudice to the national regulations, the affected **Grid Operator** shall be supported by the **SMO** and the rest of **Grid Operators** by increasing import or by activating contracts of mutual support previously signed, adopted by **WAPP**, and approved by **ERERA**. Such contracts shall be used without prejudice to the market rules and they shall specify quantities, prices, and the conditions under which the support cannot be fulfilled.

OC 6.7.2.6 In case the support required in article OC 6.7.2.5 is not sufficient, the affected **Grid Operator** may recover the amounts of **Reserves** deficit by implementing **Load Shedding** measures in its **Power System**.

- OC 6.7.2.7 When the **Downward Reserve** is less than a given threshold, the affected **Grid Operator** shall disconnect **Generation Facilities**, but the **Grid Operator** shall be justified to keep running enough internal **Generation** to cope with variations in inertia, voltage regulation and **Restoration** capabilities. For this purpose, the involved **Grid Operator** is justified if it:
- a) communicates a reduction of the **NTC** or curtail the scheduled import;
 - b) curtails the non-regulating resources. In this case also **Dynamic Security Assessments (DSA)** must be run, and the import shall be reduced according to the priorities given by the regulations or when the reduction of internal resources would hamper the functioning of the **Defence Plans**.
- OC 6.7.2.8 In the situation of overproduction (e.g. due to **VRES**), neighbouring **Grid Operators** shall support the affected **Grid Operator** by increasing the import from it, applying mutual support contracts, similar to the ones stipulated in case of lack of **Upward Reserves**.
- OC 6.7.2.9 The amounts, and the share of **Reserves** for regulation, shall be agreed among **Grid Operators** of the **Synchronous Area**, in accordance with a methodology defined by the **SMO**, adopted by **WAPP**, and approved by **ERERA**.
- OC 6.7.2.10 The assessment of the needed **Reserves** depends highly on the failure rates of the **Generation Fleets** and on uncertainty of the **Demand**, hence it depends, among others, on the time-frame of the **Demand Forecast**. The assessment shall be based on the deterministic or probabilistic approach. Nevertheless, close to real-time, simplified rules can be adopted for the sake of readiness.
- OC 6.7.2.11 In both cases, a reference for the acceptable risk not to supply the **Demand** in each **Control Area** must be agreed at the **Regional** level with the **SMO**, and adopted by **WAPP**, and approved by **ERERA**.
- OC 6.7.2.12 The **Reserves** shall be calculated in terms of power (MW), and verified in terms of energy (MWh), taking into account the expected availability of the hydro resources or storage and fossil fuels.
- OC 6.7.2.13 **VRESs** shall not be included in the **Reserves**, but the probability distribution of their production shall be considered in assessing the above-mentioned **Reserves**. **VRESs** coupled with storage of such capacity can be considered dispatchable **RES** plants and shall be considered in the sizing of the **Reserves**.

OC 6.8 Management of Shortage Crisis

OC 6.8.1 *Main Actions to Cope with Shortages*

- OC 6.8.1.1 Each **Shortage** situation generates a crisis. In case of **Shortage**, the affected **Grid Operator** shall warn the **SMO** and the rest of the **Grid Operators** within its **Synchronous Area** as soon as possible. The **SMO** shall oversee the coordination of any possible action to support the affected **Grid Operator**.

- OC 6.8.1.2 The **Grid Operator** affected by a **Shortage** shall apply the curtailment of the **Interruptible Loads** according to the contracts signed, the rotating manual **Load Shedding** plan, and shall warn the **SMO** and other **Grid Operators** if the cross-border support is not sufficient to resolve the **Shortage**.
- OC 6.8.1.3 In case of **Shortage** crisis, the affected **Grid Operator** may request the **SMO** for the suspension of the market activities as far as it is concerned, and if allowed by the applicable norms, cancel maintenance schedules, order the urgent suspension of anticipated unavailability of **Generation Facilities** or **Elements**.
- OC 6.8.1.4 All **Grid Operators** shall have a well proven **Contingency** plan to cope with suspension of the market in the event of serious under-capacity situations or other critical situations.
- OC 6.8.1.5 In exceptional situations and for a limited number of hours, the **SMO**, after consultation with **WG1**, may allow to moderately derogate from the **Operation Security Standard (N-1 OSS)** and quality standards or loadability limits – i.e., the permanent or transient maximum and minimum limits in terms of currents and voltages of the **Elements** of the **Power System** within which the **Physical Operation** shall be constantly kept. The **SMO** may invoke **Emergency State** of the **Power System** to avoid the application of the rotating **Load Shedding**. Decision on terms and conditions for the derogation shall be made on a case-by-case basis, unanimously among the affected **Grid Operators** and under the coordination of the **SMO**.
- OC 6.8.1.6 The **Emergency State** of the **Power System** shall be communicated by the relevant **Grid Operator** to the national competent authorities.

OC 6.9 Seasonal Outlooks

- OC 6.9.1 Twice a year, in periods that are significant for the peak load, and falling in two different semesters of the year, to be agreed upon within **WG1**, each **Grid Operator** shall carry out dedicated seasonal studies aiming to predict and alert the **Grid Operators** of a **Synchronous Area** about potential issues, in terms of **Load** coverage and alert the **SMO** on the situation and possible solutions.
- OC 6.9.2 Seasonal outlooks shall be formulated at least as far as the **Scenarios** of weather forecast and general energy crisis are concerned.
- OC 6.9.3 **Grid Operators** of a **Synchronous Area**, within **WG1**, shall elect and mandate a **Synchronous Area Adequacy Coordinator** to collect the **Grid Operators'** contribution and draft an outlook valid for the **Synchronous Area**, where cross-border electricity exchanges and mutual support are also highlighted.
- OC 6.9.4 **Grid Operators** shall transmit the seasonal outlook to the **Synchronous Area Adequacy Coordinator** two (2) months before the beginning of the considered period.
- OC 6.9.5 **Synchronous Area Adequacy Coordinator** after collecting the **Grid Operators'** contributions shall, not later than one (1) month, issue a **Regional Seasonal Outlook** in which:

- a) **Grid Operators'** reports are summarized country by country;
- b) The mitigation plans of expected crisis are proposed, and the contribution of cross-border electricity exchanges for mitigation of critical under-capacity periods are highlighted;
- c) The expected **Reserve** margins available in the **Synchronous Area** are declared;
- d) The **Functional Operation** key risk indicators are assessed.

OC 6.9.6 Once the potential risks are verified, the **SMO**, in consultation with **WG1**, shall decide how and how often the **Functional Operation** and **Market** operation must be monitored.

OC 7. SCHEDULING AND DISPATCHING

OC 7.1 General Information

OC 7.1.1 A **Control Area** (or **LFC Area**) is a coherent part of the interconnected **WAPP Power System**, operated by a single operator, with physical **Loads** and controllable **Generation Units** connected within the **Control Area**. In the framework of the **WAPP Power System**, the **Control Area** is usually coincident with the national territory of one or more countries, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network

OC 7.1.2 An **LFC Area Operator** operates a single **Control Area**. The **LFC Area Operator** is responsible for the availability, operation and provision of **Primary Control**, **Secondary Control** and **Tertiary Control** within the **Control Area** to maintain, at the **Control Area Program** value, the real time power exchange of its **Control Area** and, if necessary, to support the **Restoration** of frequency deviation in the interconnected **Network**. When the **LFC Area** is coincident with the national territory of a country, the **LFC Area Operator** is the designated **Grid Operator**.

OC 7.2 Scheduling Process

OC 7.2.1 The scheduling process applies only for **Normal Conditions** of operation of the **Power System**.

OC 7.2.2 The **SMO** and **Grid Operators** are responsible for the coordination of the scheduling process.

OC 7.2.3 The type of control hierarchy and organization of the structure regarding the **Information** exchange for the scheduling process are the responsibility of the **SMO**.

OC 7.2.4 A **Synchronous Area** consists of multiple interconnected **Control Areas**, each of them having a centralized **Secondary Control**.

- OC 7.2.5 To fulfil its functions, **Secondary Control** shall operate by the **Network Power Frequency Characteristic** method (see OC 8.3). **Secondary Control** is applied in selected **Generation Units** of the **Generation Fleet** which are part of the **Secondary Control** loop. **Secondary Control** shall be dissociated from **Primary Control**.
- OC 7.2.6 The type of control hierarchy and organization shall not influence the behaviour or quality of **Secondary Control** in a negative way or introduce control instability (e.g. cascaded controllers with integral parts can result in impaired or unstable **Secondary Control**).
- OC 7.2.7 Each **Grid Operator** shall operate enough control **Reserves** under **AGC** by the **Secondary Control** to meet its obligation to continuously balance its **Generation** and interchange schedules with its **Load** for the **Control Area**.
- OC 7.2.8 Any change in the exchange program that occurs outside the market in an emergency exchange program is considered a change in the **Control Area Program** and shall be regulated through appropriate procedures.
- OC 7.2.9 The daily **Verification Process**, accounting and **Settlement** activities concerning cross-border exchange program are carried out by the **SMO**.
- OC 7.2.10 The **SMO** may alternatively delegate the daily **Verification Process** to a **LFC Area Operator** of a specific **Control Area**.

OC 7.3 Exchange Scheduling Data

- OC 7.3.1 The exchange program between two **Scheduling Areas** shall be agreed upon using the **Agreement Process** before the delivery. After that, the **Verification Process** shall be performed.
- OC 7.3.2 The sum of the **Control Area Programs** of all **LFC Areas** for each time unit of a **Synchronous Area** shall be at any time equal to zero. The **SMO** shall ensure this by performing the **Verification Process**.
- OC 7.3.3 An **HVDC System**, crossing the border of two **Synchronous Areas**, between two neighbouring **Scheduling Areas** or an **HVDC System**, within a **Synchronous Area**, between two neighbouring **Scheduling Areas** is considered in the **SMO's** scheduling process as an **AC Cross-Border Interconnection**, even if it is treated in the **Scheduling Area** as a **Generation Facility** or a **Demand Facility**. The exchange program concerning **HVDC Systems** shall be reported separately from the **Control Area Program** concerning **AC** links.
- OC 7.3.4 The following standard procedures for scheduling between **Grid Operators** and **LFC Area Operator** or the **SMO** apply:
- a) Standards for identification.

- b) Resolution for time interval, content, and precision of the exchanged **Scheduling Area Exchange Document (SAX)**.
- c) **Verification Process**.
- d) Troubleshooting in case of problems with data exchange.
- e) Agreed timing for processes.

OC 7.3.5 **Framework for REM Coding Scheme**

- OC 7.3.5.1 As per MC 12.1, the **SMO** shall provide each **Market Participant** authorized to participate in the **DAM** with a unique **Energy Identification Code (EIC)** to trade on the **Energy Trading System (ETS)**.

OC 7.3.6 **Electronic Data Exchange**

- OC 7.3.6.1 Electronic **Data Exchange** is used for communication between **Scheduling Areas**, **LFC Areas**, and the **SMO**. The communication facilities shall fulfil the specified availability and performance to facilitate this process. All **Grid Operators** shall be responsible for operating their IT processes, including the communication, with acceptable level of performance.
- OC 7.3.6.2 The electronic **Data Exchange** format for **Verification Process** shall be agreed upon by the involved **Grid Operators** and coordinated by the **SMO**.

OC 7.3.7 **Time Interval**

- OC 7.3.7.1 The following options of time intervals shall be allowed: $t_i = \frac{1}{4}h$, $\frac{1}{2}h$ or $1h$. The **SMO** shall determine the scheduling time interval and submit for adoption by **WAPP** and approval by **ERERA**.
- OC 7.3.7.2 The scheduling process shall be available every **Day** from 00:00 to 24:00 (UTC+1, Cotonou time).

OC 7.3.8 **Troubleshooting**

- OC 7.3.8.1 The **Parties**, involved in the scheduling process, having difficulties relating to **Data Exchange** with their counterparties shall either accept the counter energy values or agree upon the values with their counterparties.

OC 7.3.9 **Verification Process**

- OC 7.3.9.1 The **SMO** is responsible for performing the **Verification Process**.
- OC 7.3.9.2 After completing each arrangement on the cross-border exchanges with neighbouring **Grid Operators**, the **Grid Operator** shall assemble and transmit a **Scheduling Area Exchange Document (SAX)** to the **SMO** for the **Verification Process**. This transmission shall also take place in case of any modifications.

- OC 7.3.9.3 The Grid Operator is responsible for the transmission of Scheduling Area Exchange Document (SAX) to the SMO for the Verification Process.
- OC 7.3.9.4 The **SMO** shall verify the **Scheduling Area Exchange Document (SAX)**. As part of the **Verification Process**, the **SMO** shall send a status report to the respective **Grid Operators**.
- OC 7.3.9.5 The **Verification Process** compares corresponding values of the exchange programs dedicated to the same border without applying corrective measures.
- OC 7.3.9.6 A positive verification result shall have the same values for a given direction and for all time intervals in each time frame.
- OC 7.3.9.7 In case of a negative verification result, the related **Grid Operators** have the obligation to resolve it.
- OC 7.3.9.8 The aggregation of all exchange programs shall sum up to zero within the same **Synchronous Area**.

OC 7.4 On-line Interconnection System Monitoring

OC 7.4.1 General Information

- OC 7.4.1.1 The task of online interconnection system monitoring is performed during the real-time phase. In order to prevent systemic faults in the context of **LFC**, it is essential to check the **Region**-wide consistency of the input variables for real-time operation used by each **Grid Operator** involved. This comprises the control deviation used as an input value for **LFC** as well as the real-time observation of cross-border **Control Area Programs** among all **Control Areas** of the **Region**. In this regard, the **SMO** and the **LFC Area Operators** all have well-defined responsibilities.

OC 7.4.2 Control Area Program

- OC 7.4.2.1 A **Control Area Program** constitutes the schedule of the total programmed exchange of a **Control Area** which is the sum of all exchange programs and the **Compensation Program**.
- OC 7.4.2.2 The **Control Area Program** constitutes the power interchange setpoint for the **Control Areas' Secondary Control**. To prevent excessive fluctuations on interconnections when program changes occur, it is necessary that the excessive fluctuation is converted to a ramp lasting 10 minutes in total, starting five (5) minutes before the agreed change of the **Control Area Program** and ending five (5) minutes later, regardless of the time-step (1 hour, 30 minutes or 15 minutes).
- OC 7.4.2.3 To prevent unintentional frequency deviations and major control actions under undisturbed conditions, **Grid Operators** are required to maintain careful compliance with times for program changes, particularly where changes in the **Control Area Program** of several hundred MW are involved. Care must be taken to ensure that generating capacity is brought on-line or disconnected on a staggered basis.

OC 7.4.2.4 A substantial change in **Control Area Program** shall not have a negative impact upon **Functional Operation** like the type associated with a disturbance.

OC 7.4.3 ***Tie-Line Metering, Monitoring and Control***

OC 7.4.3.1 The **LFC Area Operators** shall acquire the metering data of the tie-lines to adjacent **LFC Areas** to record the energy in the timeframe used for power exchanges.

OC 7.4.3.2 The **SMO** shall be provided with data of total hourly exchange program for each **LFC Area** and real-time active power tele-measurements of each tie-line crossing the borders of the **WAPP Power System**.

OC 7.4.3.3 General controls on interconnection system between **Control Areas** are described in OC 7.4.4 to OC 7.4.7 below.

OC 7.4.4 ***Control Area Program and Imbalances***

OC 7.4.4.1 The sum of **Control Area Program** of each **Control Area** of a **Synchronous Area** shall be equal to zero at any time.

OC 7.4.4.2 The sum of **Imbalance** of all **Control Area** of a **Synchronous Area** shall be equal to zero at any time.

OC 7.4.5 ***Physical Energy Transfers***

OC 7.4.5.1 The following rule applies: the sum of the physical cross-border electricity exchanges of all **Control Areas** of a **Synchronous Area** shall be equal to zero at any time.

OC 7.4.6 ***Perturbation of Metering Equipment***

OC 7.4.6.1 The following rule applies: the **Grid Operator** of the relevant **Control Area** shall immediately inform the **SMO**, the neighbouring **LFC Area Operators** of any perturbation in the **Metering Equipment** regarding the physical cross-border electricity exchange crossing the border with the neighbouring **Control Area**.

OC 7.4.7 ***Measures in Case of Discrepancies***

OC 7.4.7.1 The following rules apply:

- a) Observation of **Imbalances** shall be used to identify and correct, as soon as possible, abnormal operating and accounting situations (e.g. abnormal values of tie-line tele-measurements, misunderstanding in setting the **Control Area Program** of a **Control Area**).
- b) When the **SMO** detects abnormal operating and accounting situations, it shall contact the **LFC Area Operator** responsible, as soon as possible, to take corrective measures and resume **Normal State** operation.

OC 7.5 Accounting and Settlement of Imbalances

- OC 7.5.1 The task of accounting for **Imbalances** shall be performed *ex-post*, on the next working **Day** following the **Day** of operation. It comprises the validation of **Meter** measurement data, followed by the derivation and matching of accounting data for the **Settlement** of the account of **Imbalances** of each **Control Area** with reference to a recording period.
- OC 7.5.2 The **Settlement** of **Imbalances** is dealt with in accordance with MC18.
- OC 7.5.3 The sum of **Compensation Programs** of all **Control Areas** within the **WAPP Power System** shall be zero.
- OC 7.5.4 ***Workflow for Accounting and Settlement***
- OC 7.5.4.1 The accounting data goes from the **LFC Area Operator** to the **SMO**.
- OC 7.5.4.2 The **Imbalance** as well as the related **Compensation Programs** are calculated and sent from the **SMO** to the **LFC Area Operator**.
- OC 7.5.4.3 The **SMO** and **LFC Area Operators** are responsible for attributing **Imbalances** which result in **Compensation Programs** for the **Control Areas**. Each level shall ensure that there is no difference (or rounding difference) induced by the allocation.
- OC 7.5.4.4 A small amount of energy which cannot be compensated, due to rounding, remains on the account of **Imbalances**.

OC 7.6 Accounting and Settlement General Rules

- OC 7.6.1 ***Accounting and Settlement Period***
- OC 7.6.1.1 The daily accounting for the **Delivery Day** “D” shall be done on the next working **Day**.
- OC 7.6.1.2 The weekly **Settlement** and invoicing shall be done for the recording period.
- OC 7.6.2 ***Time Frame***
- OC 7.6.2.1 The time frame for accounting for **Imbalances** shall correspond with the time frame of the **Control Area Program** (1h, ½ h, ¼ h). The time frame shall be the same within a **Synchronous Area** and on a common border between two areas.
- OC 7.6.3 ***Electronic Data Exchange***
- OC 7.6.3.1 Electronic **Data Exchange** for accounting and **Settlement** is required using e-mail or a dedicated **SMO**’s system.
- OC 7.6.4 ***Modification of the Accounting Process and Related Data***

OC 7.6.4.1 All involved **Grid Operators** shall provide the complete and correct **Information** to the **SMO** about all issues affecting the accounting process such as new tie lines or modifications on tie lines.

OC 7.6.4.2 In case of changes, the requesting **Grid Operator** shall inform the affected **Grid Operators** and the **SMO** at least thirty (30) **Days** in advance.

OC 7.6.5 ***Bilateral Agreement for the Accounting/Settlement Process***

OC 7.6.5.1 To perform the accounting and **Settlement** process in a correct manner, the partners of a common border shall establish a bilateral accounting agreement to define the list of tie-lines, **Meter** measurement and accounting data.

OC 7.6.5.2 **Grid Operators** shall agree on the list of tie-lines to be included in the **SMO's** accounting process. This list shall also contain **Information** about **Meter** measurement and accounting data. The list shall contain:

- a) Names of both involved **Grid Operators**;
- b) Name(s) of tie-line(s);
- c) Names of substations the tie line is connecting and the related **Grid Operators**;
- d) List of **Meter** measurement data to be used to derive the accounting value;
- e) List of **Meter** measurement data to be exchanged;
- f) Identifier (ID) for each **Meter** measurement data to be exchanged;
- g) Identifier (ID) of accounting point;
- h) If line losses are to be considered, agreement on formula to calculate accounting data;

OC 7.6.5.3 The **Grid Operators** shall agree on the exchange format for **Metering**, accounting, and Settlement.

OC 7.6.5.4 This agreed list shall be transmitted to the **SMO** for publication on its website. The data from the accounting point shall be used by all **Market Actors** involved as a unique representation of the physical energy transfer concerning the tie-line.

OC 7.6.6 ***Data Publication***

OC 7.6.6.1 At the end of each accounting and **Settlement** process, the agreed accounting data shall be **Published** by the **SMO** on its website.

OC 7.7 **Synchronous Time Correction**

OC 7.7.1 Net **Area Control Error (ACE)** in a **Cross-Border Interconnection** cannot be maintained at zero, due to possible occasional errors in tie-line **Meters**, whether due to transducer inaccuracy, problems with **SCADA** hardware or software, or communication errors, along with normal **Load**

and **Generation** variations. This means that frequency cannot always be maintained at exactly its nominal value of 50 Hz. Each **Cross-Border Interconnection** shall have a time control process to maintain the long-term average frequency at its nominal value for smooth synchronization.

OC 7.7.2 Where the mean system frequency in the **Synchronous Area** deviates from the nominal, this results in a discrepancy between synchronous time and universal coordinated time⁵. This time offset serves as a performance indicator for **Primary Control**, **Secondary Control** and **Tertiary Control** (power equilibrium) and shall not exceed the time defined by **WAPP**.

OC 7.7.3 The **SMO** is responsible for the calculation of synchronous time and the organization of its correction. Correction involves the setting of the set-point frequency for **Secondary Control** in each **Control Area** at 49.95 Hz or 50.05 Hz, depending upon the direction of correction, during the night-time hours⁶.

OC 7.7.4 When the electric time error has reached a value, to be defined by **WAPP**, where correction is required, the **SMO** shall issue instructions to the **Control Areas** to correct the electric time.

OC 7.7.5 If a **Control Area** is disconnected from the **Synchronous Area**, it should correct its electric clock time to that of the **Synchronous Area** before reconnecting.

OC 8. OPERATION RESERVE AND FREQUENCY CONTROL MANAGEMENT

OC 8.1 General Information

OC 8.1.1 Each **Control Centre** shall evaluate the quality of **LFC** of its **Control Area** by:

- a) assessing its **Primary Control** and **Secondary Control** and adjusting them if need be,
- b) ensuring that the **K-Factor** of the secondary controller, as defined in OC 8.3.6, match the **Network Power Frequency Characteristics** of the area.

The method for the evaluation shall be agreed upon with the **WAPP** in accordance with **Good Utility Practices** and be the same for all the **Grid Operators**.

OC 8.1.2 **Grid Operators** shall make available enough active power **Reserves**, in terms of promptness and duration, to keep the **Control Area Programs** constantly at the scheduled values and frequency in the **Synchronous Area** at the nominal value, in compliance with the frequency quality targets.

⁵ For example, if frequency has been running 2 mHz high (50.002Hz), a clock using Interconnection frequency as a reference will gain 1.44 seconds in 10 hours intervals $(50.002 \text{ Hz} - 50.000 \text{ Hz}) / 50 \text{ Hz} * 10 \text{ hrs} * 3600 \text{ s/hr} = 1.44 \text{ s}$.

⁶ Regulating the frequency setpoint to $50 \pm 0.05 \text{ Hz}$, every hour a variation of 6,768 sec will be. So, starting from a time error of 30 sec, in about 5 hours the time error should be next to zero.

- OC 8.1.3 The frequency quality targets and the pro quota contribution to cope with frequency deviations shall be calculated for each **Synchronous Area** in a coordinated way. This coordination shall be done within **WG2**. ANNEX A –FREQUENCY CONTROL REFERENCE VALUES gives reference values to be periodically revised and agreed by **WAPP** based on the results of appropriate studies carried out by the **WG2**.
- OC 8.1.4 The **SMO** shall evaluate the quality of control of the frequency regulation of the **Synchronous Area** in order to estimate the operational reliability of the interconnected **Network** and evaluate the **Primary Control** and **Secondary Control** of every **Control Area** (see articles OC 8.2.11, OC 8.2.14, and OC 8.3.11).
- OC 8.1.5 The accuracy of the measurements of the frequency and the links across all the borders of the **Control Areas** shall be the same and declared. Reference values are given in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES.
- OC 8.1.6 To monitor the responses of the **Generation Units** after the activation of the **Primary Reserve** and the **Secondary Reserve**, each **LFC Area Operator** must be equipped with sufficient devices to record the needed data. The storage of these data must be sufficient to permit the analysis of normal operation and incidents in the interconnected **Power System**.
- OC 8.1.7 In OC 8.2 to OC 8.3, default criteria for sizing **Reserves** are prescribed, without prejudice to different solutions agreed to and formalized in written form in the same **Synchronous Area**, also considering the **Transmission Reliability Margin (TRM)**, in order to engage the **Reserves** without causing overloads at the borders.

OC 8.2 Primary Reserve

- OC 8.2.1 The total need for **Primary Reserve** in each **Synchronous Area** (i.e. the **Overall Primary Control Reserve**) shall not be less than the active power **Imbalance** caused by the largest single incident (i.e. **Reference Incident** of a **Synchronous Area**, to be calculated based on the results of appropriate studies, which shall be updated by **WAPP** from time to time).
- OC 8.2.2 The **Reference Incident** determines the maximum instantaneous frequency deviation, which is the reference threshold above which the **UfLS** is activated. Reference values are given in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES.
- OC 8.2.3 Each **Grid Operator** shall contribute to share pro quota the **Imbalances** in the **Synchronous Area**. Therefore, the **Overall Primary Control Reserve** of a **Synchronous Area** is shared among the **Grid Operators** based on the average power production of their **Control Area** divided by the average production of the **Synchronous Area**. The **SMO**, in consultation with **WG2**, shall coordinate the calculation per **Synchronous Area** of the share of each **Control Area** on regular basis (6-12 months) on the basis of the largest incident that can occur in the **Synchronous Area** as a single event. Additional amounts in each **Control Area** are allowed for any internal needs (e.g. to cope with **Islanding**).

- OC 8.2.4 The **SMO**, in consultation with **WG2**, may propose an alternative option to the default method as per OC 8.2.3, for example, to allocate the shares of the **Primary Reserve** based on the maximum **Generation** subject to the adoption by **WAPP** and approval by **ERERA**.
- OC 8.2.5 The deployment time of the **Primary Reserves** of the various **Control Areas** should be as similar as possible, to minimise dynamic interaction between **Control Areas**.
- OC 8.2.6 **Primary Reserve** shall respond to frequency deviations without delays and in such a way to activate the total amount of power required in thirty (30) seconds. The total amount of power required shall be supplied, at least, for fifteen (15) minutes. In case of deviations lasting more than fifteen (15) minutes, **Grid Operators** shall not reduce their contribution voluntarily. The adoption of a dead band is common practice to limit the activation of the **Primary Control**. **Reference Values** are given in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES.
- OC 8.2.7 At the maximum steady state frequency deviation, the whole **Primary Reserve** shall be activated. Each **Grid Operator** shall verify the speed governors of the **Generation Fleet** in its **Control Area**.
- OC 8.2.8 At **Control Area** level, each **Grid Operator** shall contribute to the deployment of **Primary Control** with a minimum share calculated as the product of the **Overall Primary Control Reserve** of a **Synchronous Area** multiplied by a **Contribution Factor** (c_i), being the ratio between the energy produced in a **Control Area** and the total energy produced in the **Synchronous Area** in the time period under consideration. **Grid Operators** within **WG2** may agree on different minimum duration of **Primary Control** and/or differentiating it by technology or source. Reference values are given in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES.
- OC 8.2.9 The **Contribution Factors** are verified by the **SMO**, while analysing frequency disturbances.
- OC 8.2.10 A distinction is drawn between the quality of control in the entire **Synchronous Area** (overall quality) and the quality of control in each **Control Area** (local quality). Each interconnected **Control Area** must act to provide effective **Primary Control**, to ensure that a high level of overall quality is maintained.
- OC 8.2.11 The main purpose of an overall quality check to be performed by the **SMO** is to evaluate the performance of the **Primary Control** of the entire **Synchronous Area**. This is achieved by analysing the system frequency of the **Network** during disturbances. The main purpose of this frequency analysis is to estimate the operational reliability of the interconnected **Network**. The **Network** power frequency characteristic of the entire **Synchronous Area** is calculated by the following relationship:

$$\lambda = \Delta P / \Delta f$$

with:

- a) ΔP being the variation in power causing a disturbance and,

b) Δf being the quasi-steady-state frequency deviation in response to a disturbance.

OC 8.2.12 Δf is determined from a "smoothing line" drawn between ten (10) and thirty (30) seconds after the disturbance (Figure OC 2).

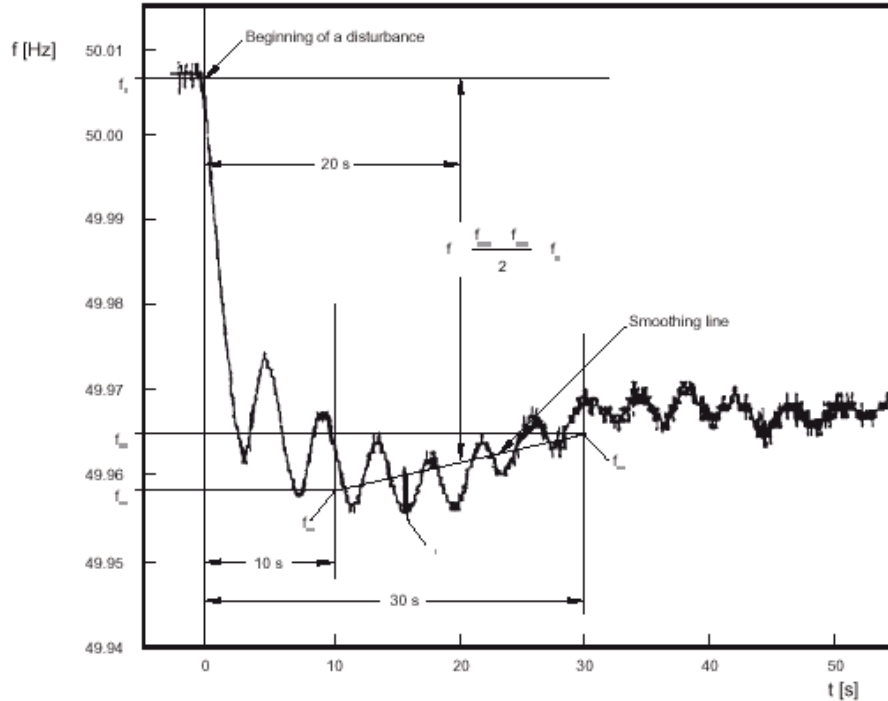


Figure OC 2. Representation of the "smoothing line".

OC 8.2.13 The main part of the **Primary Reserve** shall be activated after twenty (20) seconds, while the contribution of **Secondary Control** to the correction of the disturbance will not yet be perceptible.

OC 8.2.14 A local quality check will allow each party to ascertain whether their respective contribution to **Primary Control** is consistent with the requirements. An interconnected **LFC Area Operator**, in coordination with the **SMO**, can check the quality of its **Primary Control** by evaluating the **Network** power frequency characteristic in its **Control Area** each time a disturbance occurs and comparing it with the **Network** power frequency characteristic of the entire **Synchronous Area**. The network power frequency characteristic in a **Control Area** is calculated by the following relationship:

$$\lambda_{CA} = \Delta P_{CA} / \Delta f$$

With:

- a) ΔP_{CA} being the variation in power generated in a **Control Area** in response to a disturbance, measured at interconnecting points of the tie-lines between adjacent **Control Areas**.
- b) Δf being the quasi-steady-state frequency deviation in response to a disturbance of ΔP .

OC 8.2.15 ANNEX B –PROPOSED TEST PROCEDURE FOR THE PRIMARY CONTROL OF THE GENERATION UNITS in reports a proposed procedure to establish a rapid diagnosis of the contribution from the **Generation Units** to the **Primary Control**.

OC 8.3 Secondary Reserve

OC 8.3.1 According to the principle that each **Grid Operator** of a **Synchronous Area** shall use all internal resources to avoid spreading the impact of any **Contingency** that occurred in its **Power System** to the rest of the **Interconnected Member States**, the **Secondary Reserve** of the **Grid Operator** itself shall:

- a) be sufficient to replace the amount of **Imbalance** caused by loss of **Generation** and/or **Demand Forecast** errors in its **Control Area**;
- b) recover the frequency in the **Synchronous Area** to its nominal values.

OC 8.3.2 **Grid Operators** of the same **Synchronous Area** shall agree on the methods of calculation of the minima amounts of **Secondary Reserves** that each **Grid Operator** is obliged to make available. In case of no agreement, they shall fix the target to have sufficient resources, at least, 99.9 % of time. Consolidated convolution integral method between **Demand Forecast** error and the probability of **Generation** unavailability shall be adopted in such a case.

OC 8.3.3 In no case shall the **Secondary Reserve** be less than the **Nominal Power** of the largest **Generation Unit** in the **Control Area**. Each **Grid Operator** is responsible for this, and it shall alert the **SMO** if this condition cannot be respected.

OC 8.3.4 Default values of the **Secondary Reserve** depend on the lead time of the forecast. Close to real-time the **Nominal Power** of the largest **Generation Unit** in the **Control Area** could be enough as default value, while the day before, due to the uncertainty of the **Demand Forecast** and the **VRES**, the default value of the **Secondary Reserve** could be greater than the **Nominal Power** of the largest **Generation Unit** in the **Control Area**.

OC 8.3.5 **Grid Operators** shall control the use of the **Secondary Reserve** resources by means of an automatic **LFC** system. In case of full deployment of automatic **Secondary Reserve**, the further needs of **Secondary Reserve** can be activated manually. Hence **Grid Operators** shall adopt a coordinated **Automatic Generation Control (AGC)** system including a central regulator in the **SCADA**, telecommunication links between the central regulator and the regulators on board of the **Generation Unit**.

OC 8.3.6 The **LFC** shall be proportional-integral type driven, in input, by the **ACE** – i.e. a linear combination of system frequency bias and power deviation, according to the following:

$$ACE = \Delta P + k \Delta f$$

Where:

- a) $\Delta P = P_{\text{meas}} - P_{\text{prog}}$
- b) $\Delta f = f_{\text{meas}} - f_0$
- c) P_{meas} is the sum of the measured active power transfers on the tie-lines between adjacent **Control Areas**.
- d) P_{prog} is the **Control Area Program**.
- e) k is the **K-Factor** of the **Control Area** under consideration.
- f) f_{meas} is the measured **Power System** frequency
- g) f_0 is the set-point frequency (50 Hz)

OC 8.3.7 In thirty (30) seconds, the **LFC** must start to reduce till zero the **ACE** as soon as possible but no later than twenty (20) minutes without overshooting.

OC 8.3.8 The cycle time of the **LFC** shall be set between one (1) and five (5) seconds.

OC 8.3.9 **K-Factor** is calculated on regular basis (6 – 12 months), as a percentage of the **Overall Network Power Frequency Characteristic** of the **Synchronous Area**. The **Grid Operators** of the same **Synchronous Area** shall coordinate to share the algorithms to adopt data and calculations for approval. Unless the **Grid Operators** belonging to the same **Synchronous Area** agree on different calculation, the **K_i-Factor** for each **Control Area** is the product of the **Contribution Factor** (c_i) and the **Overall Network Power Frequency Characteristic** of the **Synchronous Area**.

OC 8.3.10 Different share and parameters of the **K_i-Factor** are subject to agreement among **Grid Operators** within **WG2** or **Synchronous Area**.

OC 8.3.11 To allow the continuous monitoring of the quality of **Secondary Control**, the frequency deviation and active power deviations are evaluated statistically each month by determining the standard deviation. The following shall also be measured and monitored:

- a) Frequency deviations > 200 mHz
- b) Proportion of time during which the frequency deviation exceeds 200 mHz

OC 8.3.12 The quality of **Secondary Control** must be monitored per **Synchronous Area** by measuring and analysing control in individual **Control Areas** after losses of **Generation** or **Load** exceeding the value determined by the **SMO** on yearly basis. The exact size of the loss shall be provided by the **LFC Area Operator** concerned to the **SMO**. The following **Information** is required for this purpose:

- a) the location of the disturbance, date, and time of the disturbance,
- b) the amount of **Generation/Load** lost or added **Load** during the disturbance

OC 8.3.13 The **SMO** shall investigate, prepare report, and communicate to all interconnected **Parties**.

OC 8.3.14 The **AGC** shall allow the following special control modes (in accordance with **UCTE** policies):

- a) *Frequency Control Mode*, that is the **Grid Operator** does not activate the ΔP component of **ACE**;
- b) *Tie-Line Control Mode*, that is the frequency control error Δf is not included in the **ACE**;
- c) *Frozen Control State*, that is, no set points of the **Secondary Control** are activated, and no **ACE** is controlled till the normal functioning mode is re-activated;
- d) *Stopped Control State*, that is in extreme conditions the **AGC** system is disabled and the set points are reinitialized.

OC 8.4 Tertiary Reserve

OC 8.4.1 **Tertiary Reserve** size is the same order of magnitude of the **Secondary Reserve** (at least the largest loss of power), being used for replacement when **Generation Outages** and/or forecast errors last more than a given time and **ACE** cannot be reduced to zero. The **Tertiary Reserve** is activated by rescheduling the production in a **Control Area** where regulating resources are exhausted, or **Load** has been cut. **Tertiary Reserve** can be partially or totally supplied by non-spinning **Generation Units**. For non-spinning **Generation Units** a mix of **Generation Units** with start-up times between thirty (30) minutes and six (6) hours is recommended.

OC 9. REAL-TIME MONITORING AND CONTROL

OC 9.1 Monitoring and Control Standard tools

OC 9.1.1 The task of online monitoring and control is performed in real-time. In order to prevent systemic faults in the context of **LFC**, it is essential to check the **Region**-wide consistency of the input variables for online operation used by the **Entities** involved. This checking comprises the control deviation used as an input value for **Load Frequency Control** as well as the real-time observation of cross-border power exchanges among all **Control Areas** of the **WAPP Power System**.

OC 9.1.2 All **LFC Area Operators** shall have the responsibility to supply these input variables to the **SMO** to monitor the interconnection of the **WAPP Power System**.

OC 9.1.3 Monitoring and control shall be based on various layers of activities and require an efficient communication infrastructure. As far as this **Operation Code** is concerned, **Grid Operators** shall comply with a minimum standard capability to monitor and control the balancing and the flows. In this regard, they shall adopt the same solutions as far as the **Relevant Grid** is concerned.

OC 9.1.4 In case of a large disturbance which threatens the reliability of the **WAPP Interconnected Transmission System**, the **SMO** shall set up a procedure to collect from the **Grid Operators**, the

data needed to analyse the events and to produce a disturbance report that could be used later for post-event analysis.

OC 9.2 ICT Platform

OC 9.2.1 **Information and Communications Technology (ICT)** platforms shall be used for **Operational** coordination among the **Grid Operators** of a **Synchronous Area**, at least, for real-time supervision and **Outage Planning Coordination Business Process**.

OC 9.2.2 Considering the perspectives of expansion of the **Cross-Border Interconnection**, all **Grid Operators** shall adopt highly interoperable solutions according to the most recent technology and **Good Utility Practices**, upon confirmation by the **SMO**.

OC 9.2.3 **Grid Operators** shall:

- a) guarantee the widest interoperability at **WAPP Power System** level.
- b) adopt protocols in common and aligned to relevant **Good Utility Practices**.
- c) commit to cooperate for upgrading the **ICT** platform, whenever efficiency or interoperability is at stake.

OC 9.2.4 **Grid Operators** in **WG3** shall issue technical guidelines for harmonized solutions and for the day-to-day practices on the **ICT** platform. In this regard, active participation in the standardization bodies is recommended.

OC 9.2.5 The **ICT** platforms shall guarantee high dependability and redundancy. Communication part of this platform is the **Wide Area Network (WAN)** linking the **Control Centres** and dedicated to the **Operation Data Exchanges**.

OC 9.2.6 Only **Grid Operators** may have access to the **WAN** of the **WAPP Power System**. They are responsible for the protection of the **WAN** of the **WAPP Power System** against external intrusions and threats. **Grid Operators** shall ensure that their **WAN** comply with the security requirements and performance standards. **SMO** shall have the permission and the endorsement of **Grid Operators** to have access to their **WAN** and shall comply with the same protection standards.

OC 9.2.7 All **Grid Operators** and the **SMO** having access to the communication platform shall be subject to confidentiality obligations.

OC 9.2.8 **Grid Operators** and the **SMO** are not allowed to directly exchange **Information** with external networks, internet included. **Grid Operators** and the **SMO** shall interpose intermediate gateways to guarantee security, if **Information** with external networks is necessary.

OC 9.2.9 **Grid Operators** and the **SMO**, within **WG3** activities, shall agree on:

- a) Protocols (e.g. TASE.2, FTP, CIM).

- b) **ICT** system administration.
- c) Location of servers.

OC 9.2.10 To keep the **WAPP Power System WAN** dependable, each **Grid Operator** and the **SMO** shall be connected to the **ICT** communication system and host two connections for routing the Information from and to two different **ICT** network service provider of the **Interconnected Member States**. The connections shall consist of private links operable at 10-100 Mbit/sec.

OC 9.2.11 The dedicated and protected communication structure is required to exchange **Operational Data** and real-time **Information**. Voice IP and **Wide Area Protection System (WAPS)** signal are not allowed to be exchanged by means of the **WAPP Power System WAN**.

OC 9.2.12 **Real-Time Data Exchange** is the first priority. The **WAPP Power System WAN** shall be mostly dedicated to:

- a) The **Warning System**.
- b) All the measurements and signals of the **Relevant Grid**.
- c) The representation of the full topology of the **Relevant Grid**.

OC 9.2.13 The second priority is the **Data Exchange** typical of near real-time **Operation**, e.g. **Grid Models** for intraday activities, unpredicted unavailability of elements.

OC 9.2.14 The last priority is the exchange of data for **Outage Planning Coordination Business Process**, that is:

- a) **Individual Grid Models** and **Common Grid Model**;
- b) **NTC**;
- c) **Unavailability Plans**.

OC 9.3 SCADA

OC 9.3.1 The application component of the **ICT** platform shall encompass the **SCADA** and the **Energy Management System (EMS)**.

OC 9.3.2 **Grid Operators** and the **SMO** shall adopt an efficient, reliable, and dependable **SCADA** system.

OC 9.3.3 Regarding the **Cross-Border Interconnection**, the **SCADA** shall import and export the statuses of the switchgears to reproduce the topology and the associated tele-measures of the **Relevant Grid** to guarantee the most efficient visibility. This visibility of the actions on the **Relevant Grid** shall be considered vital for coordinated and individual emergency actions.

- OC 9.3.4 The general requirements of the **SCADA** shall concern:
- a) Sampling period, as much as possible uniform (e.g. 2-4 sec) in the same **Synchronous Area**;
 - b) **LFC** as specified in this **Operation Code**.
- OC 9.3.5 **SCADA** shall perform at least the following applications:
- a) Efficient human-machine interfaces and alarm systems;
 - b) Comparison forecast against actual, at 15-minute intervals, of mean powers regrouped at various internal zone levels, at **Bidding Zone** level and the whole **Control Area** level;
 - c) Dedicated displays for **RES** productions;
 - d) **State Estimator**.
- OC 9.3.6 **SCADA** systems shall be subject to cyber security guidelines and self-assessments, at least, to verify the security level and cyber risk across the **Grid Operators** connected in the **Information** exchange **WAN**.

OC 9.4 Energy Management System (EMS)

- OC 9.4.1 The **EMS** is the package of applications strongly connected to the **SCADA** system encompassing complex computer-based tools designed to support the decisions of the **Grid Operators** in the control rooms.
- OC 9.4.2 **Grid Operators** shall adopt efficient **EMS** according to the principle that the better they run their **Power System** the more secure is the **Functional Operation** of the whole **WAPP Power System**.
- OC 9.4.3 In addition to the applications for internal **Functional Operation** (e.g., real-time optimal power flow), it is recommended to include in the **EMS** package, at least, the following applications, with focus on **Cross-Border Interconnection** issues:
- a) **N-1 OSS** checks at time intervals between five (5) and fifteen (15) minutes;
 - b) The **Dynamic Security Assessment**;
 - c) Command systems to record the dispatching orders to the **Generation Units** and to the **Certified Traders**.
- OC 9.4.4 Concerning the **Cross-Border Interconnection**, the **EMS** shall also include a **Warning System (WS)** to simultaneously alert, in real-time, the **Grid Operators** of incoming or ongoing criticalities. The **WS** shall consist of a series of synoptic pages of displays representing the **Control Areas** of the **Synchronous Area**. These **Control Areas** are represented with frequency, amount of actual cross-border electricity exchanges compared with the exchange program and voltages in

the pivotal nodes of the **Transmission System**. Such synoptic pages of displays are the same for each **Grid Operator** and shall be used to immediately and simultaneously alert all the **Grid Operators** by means of different colour codes when security thresholds are violated.

OC 9.5 Recording of the Electrical Behaviour of the Assets

OC 9.5.1 To analyse the behaviour of the **Cross-Border Interconnections**, tie-lines shall, at least, be equipped with fault and event recorders associated with the protection system or the substations of the **Synchronous Area**.

OC 9.5.2 The tie-lines shall be equipped with fault locators, in order to immediately alert the crews on the side of the tie-line where the fault has occurred and accelerate the urgent repair activities.

OC 9.5.3 It is recommended to complement the conventional monitoring system with **PMUs** in such a way to build up an efficient monitoring network of the dynamic phenomena in **Synchronous Areas**. The collected data shall be shared among all **Grid Operators** of the **Synchronous Area** and shall feed the **DSA**.

OC 9.6 Control Room Activities in Control Centres

OC 9.6.1 Neighbouring **Grid Operators** shall constantly maintain contact to control their **Control Area** and the **Cross-Border Interconnection** 24 hours per day, 7 days per week. **Control Centres** are the corresponding **Entities** entitled to take coordinated decisions about the interconnected **Functional Operation**.

OC 9.6.2 Regarding real-time control, neighbouring **Grid Operators** shall:

- a) List, in written form, the most used and /or critical dispatch instructions with complete descriptions in English and French;
- b) Agree and adopt a common operational language;
- c) Have redundant hot lines between control rooms of the **Control Centres** and the **SMO**;
- d) Agree on protocols to perform complex activities in autonomy under specific conditions (e.g. **Restoration** sequences).

OC 9.6.3 Neighbouring **Grid Operators** shall reciprocally exchange their respective **Contingency List** and corresponding **Remedial Actions** available for the performance of **DSA**. These data shall also be supplied to the **SMO**.

OC 9.6.4 **Grid Operators** and the **SMO** shall guarantee the skills of their physical operators and their diligent and professional attitude.

OC 9.6.5 For the purpose of protecting the conduct of the physical operator, and without prejudice to the applicable national regulations, in particular on labour laws or the protection of personal

data, it is recommended to record the telephone calls between operators, protect them and retrieve them only in case of formal inquiries. Notwithstanding the applicable national regulations in each of the **Member States**, a procedure is needed to regulate the implementation of such measures.

OC 9.6.6 Regarding the routine applications that the operators in the **Control Centres** shall perform, the following rules apply:

- a) Provide the **SMO** with the data set describing the relevant characteristics of the **Power System** (**Generation**, **Demand** and **Grid** topology) and applicable rules for modifying these characteristics during the **NTC** calculation process, to create a **Common Grid Model** for **Networks** analysis;
- b) perform the security analysis at regular intervals and on demand when the operational conditions require it;
- c) manage the **LFC** and the balancing **Reserves**;
- d) warn, as soon as practicable, about criticalities arising within their **Control Area**;
- e) perform the **Restoration Plan** in cooperation with the neighbouring **Grid Operators** and the **SMO**.

OC 10. DATA, DOCUMENTS, AND INFORMATION EXCHANGE

OC 10.1.1 The exchanges of all the data, documents, and **Information**, among **Grid Operators**, the **SMO**, **WAPP**, **ERERA** and/or **National Regulatory Authorities**, are made according to the **Operational Procedures** set out by the **SMO**, adopted by **WAPP** and approved by **ERERA**. The mandatory data to be exchanged are presented in OC 10.2 to OC 10.5.

OC 10.2 Annual Operation Report

OC 10.2.1 The **Annual Operation Report** shall be used to promote, among **Member States** and external entities, the **Cross-Border Interconnection**, highlighting progress in **Functional Operation** and the market. It shall be **Published** annually by the **SMO**.

OC 10.2.2 Notwithstanding the policies and obligations on confidentiality, **Grid Operators** shall cooperate with the **SMO** to enable the **SMO** to regularly issue the **Annual Operation Report** with the details of **Synchronous Areas** and isolated **Grids**. With reference to year “Y”, the **Annual Operation Report** should be issued no later than the first quarter of Y+1.

OC 10.2.3 The **Annual Operation Report** shall, at the minimum, address the following topics:

- a) Main facts and figures;
- b) **Demand** in energy and power;

- c) Amount of cross border electricity exchanges, border-by-border;
- d) **Generation** per source;
- e) **RES** penetration progress;
- f) Relevant facts and events including major disturbances and crises;
- g) Any other topic that **Grid Operators** jointly decide to report.

OC 10.2.4 The **SMO**, with the support of **WG2**, shall coordinate the data collection and the drafting activity for issuing a quarterly report on frequency and power exchanges.

OC 10.2.5 Sensitive or confidential **Information** related to the **Annual Operation Report** shall be forwarded exclusively to the involved **Grid Operator** for actions pertaining to its **Grid**.

OC 10.3 Data for Fault Analysis

OC 10.3.1 Ordinary faults on the cross-border tie-lines shall be considered as routine activities regulated by the **Operation Agreements**.

In case of major disturbances involving more than one **Grid Operator**, the **SMO**, in consultation with **WG2**, shall appoint a technical investigation team to prepare a common shared report. For this purpose, **Grid Operators** shall exchange data for analysis in the format and detail requested by such a team. Such report should analyse at least:

- a) Pre-fault conditions;
- b) Inception of fault and its evolution;
- c) Protection and **Defence Plan** response;
- d) Operators' conduct;
- e) Root causes and lessons learned.

OC 10.4 Data for Statistics

OC 10.4.1 Data statistics shall be the basis of forecast both in **Functional Operation** and planning. Historical data shall be stored in the common database and maintained by the **Grid Operators**.

OC 10.4.2 The collection of statistical data shall be done regularly and verified by the **SMO**. Any change after collection shall be registered and verified by the **SMO**.

OC 10.5 Documentation

OC 10.5.1 The **Interconnection Agreement** shall be the main technical document necessary to safely manage the **Cross-Border Interconnection Facilities**. It shall be a formal and duly registered document. Any changes shall be agreed in advance and properly recorded.

OC 10.5.2 The **Interconnection Agreement** refers to a single **Cross-Border Interconnection Facility**. For each of them, the **Interconnection Agreement** shall include:

- a) all data on property and identification of the **Connection Point**, i.e. the interconnector including the sending and receiving substations;
- b) the physical (in terms of ownership) and **Operational** boundaries;
- c) the list of **Elements**;
- d) all nominal (physical) characteristics of each single **Element** in steady state and transient conditions;
- e) the certification of all tests passed at the acceptance of the **Facility**;
- f) the names and addresses of personnel, classified per position and role (e.g. responsible, operator in shift, etc.) attending to the substation and the same for the personnel of the **Control Centres**;
- g) single line diagram of the substations including positions of switchgears and **Instrument Transformers**;
- h) the full fault protection scheme;
- i) the settings of the fault protections;
- j) automation;
- k) **WAPS** (if any);
- l) the **Metering Equipment**;
- m) the safety rules and safety procedures;
- n) the maintenance responsibilities.
- o) the operation of **FACTS** or **HVDC Systems** in terms of control modes and the reactive power compensation.

OC 10.5.3 The full protection scheme setting coordination shall be carried out jointly, according to defined procedures such as:

- a) maintenance procedures (type, periodicity, repair and replacement of devices or their components).
- b) testing of all the protections on the interconnections.

OC 11. TESTING AND PERFORMANCE MONITORING

OC 11.1.1 The responsibilities and obligations of each **Grid Operator** towards other interconnected **Grid Operators** shall mostly relate to the efficiency of machinery, equipment, and procedure of the **Grid Users** of its **Control Area**. To support the **Grid Operators** in carrying out their own responsibility relating to the **Functional Operation** of the interconnected **Power System**, this **Operation Code** prescribes to rely on the performances of the **Grid Users** by means of regular periodic tests. The frequency of the periodic tests, the testing modalities and in general the performance control are regulated and organized by the **Grid Operators** according to the agreements in force.

OC 11.1.2 Notwithstanding the provisions of the respective **National Grid Codes** regarding performance control, **Grid Operators** are required to perform or cause **Grid Users** to perform periodic tests on:

- a) the **Restoration Plans**, including **Black-Start Capabilities** of **Generation Facilities** and reconnections of **Demand Facilities**;
- b) the **Emergency** procedures;
- c) the frequency regulation capabilities of **Generation Units**;
- d) the **UfLS** or **UVLS** relay operations;
- e) any other device, procedure or computer-based application according to a testing plan that **Grid Operators** consider vital for the **Security of Operation (SoO)**.

OC 11.1.3 Methods of testing shall be the sole decision and responsibility of the **Grid Operators** who periodically report to **WG2** on the status of such tests, according to the timeframe defined by the **SMO**.

OC 11.1.4 The **Grid Operators** shall maintain updated internal inventories of the **Generation Units** tasked to provide **Black-Start Capabilities** and other services in **Restoration**. **Grid Operators** should attach to the inventories, registers where the tests and their outcomes are recorded. **Grid Operators** shall limit the access to the **Information** of such registers.

OC 12. SYSTEM OPERATORS' TRAINING

OC 12.1.1 Provisions concerning training of the **System Operators** for **Operational** matters are regulated by the **Operators' Training Code**.

OC 13. CYBERSECURITY

OC 13.1.1 The bulk **Power System** shall be considered by the **Member States** as a mission critical infrastructure. As such the cybersecurity of each **Grid Operator** of the **Cross-Border**

Interconnection shall comply with the respective national policies and their confidentiality requirements.

OC 13.1.2 As far as the **ICT** infrastructure in common adopted for **Real-Time Data Exchange** and **Outage Planning Coordination Business Process** are concerned, the **SMO**, in consultation with **WG3**, shall issue cybersecurity guidelines which include:

- a) The self-assessment of the vulnerability and resilience capabilities proven by resilience tests;
- b) The analysis of cyber threat **Scenarios**, risk assessment and security plans;
- c) The organization of physical mitigation measures;
- d) Procedures of response to attacks.

OC 13.1.3 **Grid Operators**, in a holistic approach, shall self-certify the compliance with requirements about physical and functional segregation, and access control to structures, applications and infrastructure in common for **Functional Operation**.

OC 14.RECOMMENDATION ON SAFETY

OC 14.1.1 This **Operation Code** does not intend to replace safety rules, which are a set of approved rules for safe access to substations, switchyards and other **Elements** of the **Grid** and keep workers safe when they are exposed to the hazards on the **Transmission System**. Safety is the responsibility of the **Grid Operators**.

OC 14.1.2 Under no circumstances shall the **Operation Code**:

- a) be construed as replacing or modifying the safety rules in force within the jurisdiction of the **Grid Operators**.
- b) be a direct or indirect inducement to infringe the safety rules and procedures agreed at the time of any intervention on the interconnectors.

OC 14.1.3 Safety shall take precedence over any other issue relating to the **Functional Operation** of the interconnected **Power System**.

OC 14.1.4 Within the scope of the **Operation Code**, the recommendations of the **Operation Code** are limited to the safety of the **Cross-Border Interconnections** and shall apply to:

- a) Measures to safeguard against electrical hazard;
- b) the cross-border **Elements** of the **Transmission System** involving at least two **Grid Operators**;

- c) maintenance and / or testing activities.

OC 14.1.5 The neighbouring **Grid Operators** shall attach to the **Interconnection Agreement** the safety procedures and the reference safety rules adopted for each specific interconnector. The safety procedures for that specific interconnector shall be attached as well. Following any change of rules and layout of the assets, these documents shall be agreed upon, updated and notified to whom it may concern.

OC 14.1.6 This **Operation Code** recommends:

- a) The on-site availability of safety coordinators officially designated by each **Grid Operator** for all the sites where safety procedures have to be applied;
- b) The formal authorization of the safety coordinators;
- c) Coded recording and traceability of the **Safety Precautions** from the time of its request to cancellation, in the **Record of Inter System Safety Precautions** ;
- d) Unambiguous identification of the parts of the interconnector subject to **Safety Precautions**.

OC 15.REQUIREMENTS FOR SYNCHRONIZATION OF POWER SYSTEMS

OC 15.1 General Information

OC 15.1.1 This chapter OC 15 addresses requirements for synchronization of **AC-based Power Systems**. The synchronization refers to the activity required to make the previous **Asynchronous Areas** synchronous. The result is a **Synchronous Area** that is reliable and suitable for the purposes of the **Functional Operation**.

OC 15.1.2 The synchronization of two **AC-based Asynchronous Areas** into one **Synchronous Area** requires a set of actions when these areas are connected for the first time. This OC 15 outlines the main conditions to be fulfilled during the synchronization phases, including lists of studies and tests to be performed in each **Asynchronous Area** (before synchronization) and under interconnected **Operational** conditions (after synchronization).

OC 15.1.3 The synchronization is an event involving all the **Grid Operators** of the areas to be synchronized. The synchronization shall be accepted by all involved **Grid Operators** unless the interconnected operation in the **Synchronous Area** impacts the reliability and stability of the **Power System** of a **Grid Operator**.

OC 15.2 Harmonization of the Operational Procedures

OC 15.2.1 Prior to the implementation of a synchronous **Cross-Border Interconnection**, the **National Grid Codes** and the **Operational** practices of the involved **Grid Operators** shall be

assessed, harmonized and adapted to the requirements of the **REM Codes**. The assessment shall include selection of rules, obligations and procedures that are mandatory for compliance and the roadmap to achieve full compliance. This assessment process is supported and coordinated by the **Compliance Evaluation Group** set in the **Transitional Provisions Framework**, as ruled in the **General Conditions**.

OC 15.2.2 The harmonization process shall be concluded before the first commercial **Functional Operation** in the **Synchronous Area**.

OC 15.2.3 Final decision for synchronization and connection shall be taken unanimously by all **Grid Operators** involved in the expected **Synchronous Area** on the basis of the proposal of the **SMO**.

OC 15.3 Load-Frequency Control

OC 15.3.1 When connecting two (2) or more asynchronous **Power Systems**, each relevant **Grid Operator** shall guarantee to respect its own obligations concerning **LFC** within its **LFC Area** according to the requirements set in this **Operation Code** (see OC 8).

OC 15.3.2 Each **Grid Operator** shall be responsible for operating according to the **LFC** structure of its **Synchronous Area**.

OC 15.3.3 The principles and obligations to be defined in the agreement of **LFC** for each **Grid Operator** operating an **LFC Area** include:

- a) collection and calculation of the **Control Area Program** between the areas in accordance with the Scheduling and Dispatching in OC 7 of this **Operation Code**;
- b) measurement and monitoring of the energy transfers on tie-lines;
- c) calculation (or measurement) of the **Area Control Error (ACE)**; and
- d) operation of the frequency restoration process.

OC 15.3.4 The **Grid Operators**, under the coordination of the **SMO**, shall agree on the total amount of **Primary Reserve** and its allocation among **Interconnected Member States**, in particular:

- a) The basic dimensioning criterion of the **Primary Reserve** shall be based on the capacity to withstand the **Reference Incident** in the relevant **Synchronous Area** by containing the system frequency within the maximum instantaneous frequency deviation and stabilizing the system frequency within the maximum steady-state frequency deviation. The determination of the **Reference Incident** shall take into account the maximum expected instantaneous power deviation between **Generation** and **Demand** caused by a **Normal Contingency**. The **Reference Incident** shall be determined by taking into account, at least:
 - i. the loss of the largest **Generation Unit**;
 - ii. loss of a line section;

- iii. loss of a bus bar;
 - iv. the loss of the largest **Demand Facility**.
- b) The primary frequency control and minimum target performance shall include the definition of:
- i. the required accuracy of local frequency measurements;
 - ii. the **Frequency Response Deadband** of the governor of the regulating units;
 - iii. the minimum value of **Nominal Power** above which each **Generation Unit** shall be included in a group of regulating **Units**;
 - iv. the physical deployment time of the **Primary Reserve** at the occurrence of frequency deviation from its nominal value;
 - v. the minimum duration for the capability of **Primary Control** delivery;
 - vi. the frequency deviation for full activation of **Primary Reserve**;
 - vii. the cycle for measurements of the system frequency.

OC 15.3.5 To restore the frequency to its nominal value following a disturbance, the **Secondary Reserve** shall be activated. The **Grid Operators**, with support of the **SMO**, shall develop and agree upon the terms and conditions, or methodologies for the determination of the total amount of **Secondary Reserve** and its allocation among **Interconnected Member States**.

OC 15.3.6 The **Grid Operators** shall avoid manual procedures and shall implement an automatic control of frequency and energy transfers when operating in synchronous **Functional Operation** according to a power-frequency controller which considers deviations of power exchange as well as frequency from the corresponding set points. The automatic controller shall be integrated into an **Automatic Generation Control (AGC)** to achieve the following primary objectives:

- a) To maintain frequency at the nominal value.
- b) To maintain the **Control Area Program** with the neighbouring **Control Area** at the scheduled values.

OC 15.3.7 The control signal of **Automatic Generation Control (AGC)**, referred to as set-point, shall be divided among the **Generation Facilities** under control by using participation factors.

OC 15.3.8 In case of observed or expected sustained activation of **Secondary Reserve**, the **Tertiary Reserve** shall be activated. The **Grid Operators** shall develop and agree upon the terms and conditions or methodologies for the determination of the total amount of **Tertiary Reserve**. **Grid Operators** are responsible for making available the total amount of **Tertiary Reserve** within their **Synchronous Area**.

OC 15.4 Voltage and Reactive Power Control

OC 15.4.1 Within a **Synchronous Area**, each **Grid Operator** shall ensure reactive power reserve with adequate level and time response, in order to maintain the voltages on interconnectors and neighbouring busses within the ranges set out in the **National Grid Codes**.

OC 15.4.2 The **Control Centres** of the **Grid Operators** shall jointly define the adequate voltage control regime and determine the voltage control actions to ensure that the common **Security of Operation (SoO)** limits are adhered to and prevent a voltage collapse of the interconnected **Power System**.

OC 15.4.3 The **Control Centre** of each **Grid Operator** shall agree with the **Generation Facilities** connected to its **Grid** on the reactive power set points of **Generation Units**, power factor ranges, and voltage set points for voltage control at the **Connection Point**. The **Grid Operators** shall have the right to give voltage control instructions to **Generation Facilities** and each **Generation Facility** shall use its reactive power sources to ensure that the set points of those parameters are maintained.

OC 15.5 Interconnected Defence Plan

OC 15.5.1 The **Grid Operators** shall design a **Defence Plan** taking into account the **Security of Operation (SoO)** limits, the characteristics of their **Grids**, and the behaviour and capabilities of **Demand Facilities** and **Generation Facilities**.

OC 15.5.2 The **Defence Plan** shall include, at least, the following technical and organizational measures:

- a) System protection schemes including at least:
 - i. automatic under-frequency control scheme;
 - ii. automatic over-frequency control scheme;
 - iii. automatic voltage control scheme.
- b) System **Defence Plan** procedures, including at least:
 - i. frequency deviation management procedure.
 - ii. voltage deviation management procedure.
 - iii. interconnection power flow management procedure.
 - iv. manual **Load** disconnection procedure.

OC 15.6 Frequency limits

OC 15.6.1 The **Grid Operators** shall harmonize the limits of frequency deviations in **Normal State**, by identifying at least two sets of frequency deviations:

- a) The variation range under **Normal State** that shall be equal for the **Grids**.
- b) The upper and lower maximum values of frequency and the time duration of the frequency deviations in **Emergency State**.

OC 15.6.2 The acceptable lowest frequency values for each **Synchronous Area** shall be harmonized in order to determine a maximum instantaneous low frequency threshold common to the **Grids** based on an evaluation of a target minimum frequency at which the cascading failure, namely frequency collapse, begins. Reference values for each **Synchronous Area** are given in ANNEX A – FREQUENCY CONTROL REFERENCE VALUES. These reference values shall be periodically revised by the **SMO** based on the results of appropriate studies carried out by the relevant working group.

OC 15.6.3 The acceptable highest frequency values need to be harmonized and shall conform with the high frequency relay settings of **Generation Facilities** connected to the **Grids**.

OC 15.6.4 ***Underfrequency Load Shedding (UfLS)***

OC 15.6.4.1 Before operating the synchronous **Cross-Border Interconnection**, the **Grid Operators** shall conduct a dedicated study for a joint **UfLS** design for their **Power Systems**. The main objective of the study is to develop strategies for the coordinated **UfLS** plans to prevent frequency decays, to restore frequency in the interconnected **Grids** and to prevent unbalanced **UfLS**.

OC 15.6.5 ***Measures Against Voltage Drop or Increase***

OC 15.6.5.1 The **Grid Operators** shall have an agreement for the control of the voltage and reactive power on the tie-line with the objective of keeping the voltages within a narrow bandwidth as required by the **National Grid Codes** and a minimal reactive power flow across the tie-line.

OC 15.6.5.2 The **Grid Operators** shall conduct a dedicated study addressing the reactive power control of their **Power Systems'** operations in **Normal State** and in **Emergency State**. The study shall include at least the following:

- a) in **Normal State**, determination of the reactive power reserve requirements, distribution and dispatching of the reactive power, and possible issues due to reactive power imbalances in peak and off-peak **Demand** conditions.
- b) in **Emergency State**, development of a series of countermeasures to prevent violations of quality of power supply to **Demand Facilities**, loss of auxiliaries of **Generation Facilities**, **Facilities** trip leading to voltage collapse. The countermeasures may include on-load tap changer blocking scheme, and the implementation of system protection schemes for voltage management in form of undervoltage **Load Shedding** scheme.
- c) for the tie-line, determination of the main settings of an automatic protection for line trip in case of high or very low voltage levels. The setting of the automatic protection scheme of the **Cross-Border Interconnection** trip shall consider the amount of reactive power flow and its direction.

- d) evaluation of the possible overvoltages on the synchronous **Cross-Border Interconnection** and the overvoltage protection coordination, otherwise known as insulation coordination, in order to minimize the number of insulation failures and therefore the number of interruptions.
- e) determination of the settings of automatic overvoltage protection shall be provided at the substations of the synchronous **Cross-Border Interconnection** to prevent electric equipment damages.

OC 15.6.6 **Measures to Avoid Major Disturbances**

OC 15.6.6.1 The **Grid Operators** shall conduct a specific study for implementing the **WAPS** to protect their respective **Power Systems** in **Emergency State**.

OC 15.6.6.2 Before starting the test of the synchronisation of the **Cross-Border Interconnection**, the **Grid Operators** shall study the risk of appearance of both inter-area and local oscillations. The main objective of the study is the assessment of the steady state stability of the interconnected **Power System** by:

- a) assessing the risk of inter-area oscillations between the asynchronous **Power Systems** to be connected in interconnected operation, during all **Demand Scenarios** and cross-border electricity exchanges levels.
- b) identifying the inter-area and local electromechanical oscillations and corresponding worst (least-damped) modes.
- c) tuning **Power System Stabilizers (PSS)** of major **Generation Facilities** as the most important damping measure against the risk of inter-area oscillations.
- d) considering the determination of other preventive measures in order to ensure stable operation of the **Transmission System** after the synchronization of the **Cross-Border Interconnection**, in case of persistent stability problems due to poorly damped inter-area oscillations affecting the **Grids** even with the activation of the **PSS**.

OC 15.6.7 **Measures Against Loss of Synchronism**

OC 15.6.7.1 Before starting the operation of the synchronous **Cross-Border Interconnection**, the **Grid Operators** shall perform a **Dynamic Stability Assessment (DSA)** to identify the stability limits and possible stability problems in the interconnected **Transmission System**. The study shall use, in a complementary manner, small signal stability analysis in steady-state and transient stability analysis in dynamic state. Simulation studies shall assess and monitor the dynamic stability of the **Transmission System** in all system configurations that are likely to occur. When performing coordinated **DSAs**, both **Grid Operators** shall determine:

- a) scope of the coordinated **DSA** in terms of a **Common Grid Model**.
- b) list of agreed **Scenarios** concerning the coordinated **DSA**.
- c) list of agreed **Contingencies** or disturbances whose impact shall be assessed through the coordinated **DSA**.

- d) definition of preventive measures against loss of synchronism, such as the calculation of stability margins on the critical cut-sets. If the critical cut-set turns out to be the **AC** tie-line, these margins are to be included in the calculated maximum active power capacity over the **AC** tie-line.
- e) definition of **Remedial Actions** in order to avoid the consequences of the loss of synchronism. If the only feasible **Remedial Action** is the opening of the **AC** tie-line, the study should examine the consequences of the **Grids'** separation.

OC 15.7 Protection Systems

OC 15.7.1 **Transmission Systems** protection systems are critical to ensuring **Power System** reliability. Accordingly, independent primary and backup line protection systems shall be a requirement for the **AC** tie-line. The protection system to be applied must be capable of detecting all types of faults, including maximum expected arc resistance that may occur at any location on the protected line.

OC 15.7.2 The following protections shall be verified with particular attention to the **Relevant Grid**:

- a) Primary and back up network protection, which provide high-speed and selective fault clearing for all types of faults with and without ground.
- b) Coordination of the protection of the **Generation** against faults external to the **Generation Units** and their **Fault-Ride Through** capabilities.

OC 15.7.3 The minimal necessary defence measures shall include the installation of protections for the **AC** tie-line that can detect whether the power flow is attaining the maximum transmissible power or has already exceeded it, or can detect whether the **Power System** is evolving towards a dangerous **Operating Condition** in terms of voltage or phase angle difference. These protections can be based on a measurement of transferred power, voltage or impedance. The following system protection should be installed on both sides of the **AC** tie-line:

- a) Power flow protection based on measurement of the power flow amount and direction;
- b) Loss of synchronism tripping devices;
- c) Minimum frequency protection combined with a time delay, to ensure the **Grids** separation to restore the **Demand** and **Generation** balance in each of the separated **Power Systems** in an independent way.

OC 15.7.4 The **Grid Operators** shall determine the settings of system protection of the synchronous **Cross-Border Interconnection** through appropriate studies to ensure that the settings will not result in **Elements** tripping in case of recoverable **Operating Conditions**.

OC 15.8 Process of Synchronization

OC 15.8.1 For the synchronization process, the **Grid Operators** of the **WAPPITS** shall agree on the **Synchronization Leader** and define the procedures for the first trials or for synchronization actions to be performed after an emergency trip of the **AC** tie-line. This agreement shall describe the conditions under which synchronization shall take place.

OC 15.8.2 The **Synchronization Leader**, before closing the circuit breaker of the **Cross-Border Interconnection**, shall apply the required actions to carry out the synchronization under the following criteria :

- a) The **Power Systems** must be in a stable state and the frequencies shall be near to the nominal frequency, within a maximum tolerance agreed upon by the **Grid Operators**. A frequency difference between the **Asynchronous Areas** shall be below the value agreed upon by the **Grid Operators** before synchronizing the areas.
- b) The voltages shall be in the range agreed upon by the **Grid Operators** with respect to the nominal voltage. The difference in voltage across the open circuit breaker shall be below the value agreed upon by the **Grid Operators** before synchronizing the **Asynchronous Areas**.
- c) The voltage phase angle difference across the tie-lines shall guarantee the circuit breaker closure.
- d) The **Synchronization Leader** shall give orders to **Frequency Leaders** (i.e. dispatching operators at the **Control Centres**) for appropriate actions to minimize the frequency and voltage deviation between the **Asynchronous Areas** at the time of synchronization.

OC 15.9 Trial Period

OC 15.9.1 The trial period shall commence once the synchronous **Cross-Border Interconnection** has been energized.

OC 15.9.2 Before the energization, it is recommended to set special protection schemes able to separate the two areas in case of **Emergency State**. In this period, mutual support is not mandatory.

OC 15.9.3 The trial period shall be organized in two (2) successive phases:

- a) Phase “A”, lasting at least six (6) months, with **Control Area Program** limited below agreed thresholds. These thresholds shall not be influenced by commercial agreements and power market operation;
- b) Phase “B”, lasting at least six (6) months, with **Control Area Program** deriving from commercial agreements and power market operation.

OC 15.9.4 The **Grid Operators'** team shall propose an extension of the trial period where unsatisfactory performance of the interconnected **Power Systems** is detected. The **Grid Operators'** team could decide to interrupt the trial period in case of significant incidents.

OC 15.9.5 The trial period shall be characterized by an intense monitoring activity. Where an incident which shows serious noncompliance in the trial period, the phase of the trial period shall be extended for a duration necessary to solve the noncompliance.

OC 15.9.6 Monitoring shall focus at least on the following aspects:

- a) **Area Control Error (ACE)**;
- b) **Power System Stabilizer (PSS)** behaviour;
- c) Data recording at the occurrence of faults.

ANNEX A – FREQUENCY CONTROL REFERENCE VALUES

Without prejudice to the general principle of this **Operation Code**, the peculiarities of each **Synchronous Area** necessitate an agreement on quality targets, **Reserve** sizing and device settings among the **Grid Operators** of the same **Synchronous Area**. The agreements should take into consideration the current status of the interconnection and include transparent calculation practices.

The following considerations apply:

1. The **LFC** is the result of processes that are controlled and improved on a regular basis. They imply the regular and cooperative participation of the **Grid Operators** of the same **Synchronous Area**.
2. The technological evolution of the **Power Systems** resulting from the increasing size of the **Generation** (e.g. nuclear **Generation Facilities**), **HVDC Systems**, the ability to provide inertia (e.g. **Inverter-based Generation Units**) and the evolution of the **Load** have to be taken into consideration in sizing and setting the vital functions, that are the object of this Annex A.
3. The **UfLS** requires a strong coordination with the frequency control.

For these reasons, the **Operation Code** highlights principles and practices, supported by consolidated and affordable technologies. In this approach the **Operation Code** does not impose technical solutions which, among the others, would require more in-depth analysis for each of the **Synchronous Areas** and preliminary consensus.

Nevertheless, the intention of reference values is to trigger this process and enhance it towards further and operative decisions on this matter. The Table OC 1 and Table OC 2 are simplified excerpts of parameters adopted in **UCTE** and/or from previous studies conducted by **WAPP**, which can be considered as initial reference for the **WAPPITS**.

The values are indicated for a future synchronised **WAPP Power System**. Based on the peculiarities of the current system, these values can be disaggregated and defined for each **Synchronous Area**, and they shall be updated by the **SMO** from time to time, in coordination with the **Grid Operators**, based on the results of appropriate studies carried out by the relevant **Working Group**.

A.1 Frequency and Load Frequency Control

Table OC 1 identifies the minimum set of parameters that have to be defined and progressively adopted by the **Synchronous Areas** if different from the current ones.

Table OC 1 is structured in three (3) parts that report three (3) different sets of parameters:

1. The first one (Frequency Quality Targets) sets common objectives among the **Grid Operators** of the same **Synchronous Area**. It is recommended to consolidate them, being the guide for designing the **AGC** and for sizing the **Reserves**.
2. The second one (System Parameters) concerns the behaviour of the **Synchronous Area** translated in terms of parameters needed for sizing and sharing the participation to the regulation of the frequency and the control of the cross-border electricity exchanges.
3. The third one (Recommended Technical Standards) complements the second one with some technical characteristics to be controlled and taken into consideration.

Table OC 1. Reference values for main LFC parameters characterizing a Synchronous Area.

Notes	Parameters	Reference Values
	<i>Frequency Quality Targets</i>	
()	Standard Frequency Range [mHz]	±100
	Max Instantaneous Frequency Deviation [mHz]	800
()	Max Steady State Deviation [mHz]	200
()	Time to Restore Frequency [min]	15
	Max number of minutes outside the standard frequency range [min/year]	15000
	ACE - Average Zero Crossing Period [min]	10
	<i>System Parameters</i>	
§ £	Reference Incident [MW]	390 ⁷
§ £	Minimum Network Power Frequency Characteristic [MW/Hz]	1950
*	Average Network Power Frequency Characteristic [MW/Hz]	n.a.
*	Overall Network Power Frequency Characteristic [MW/Hz]	n.a.
£	Overall Primary Control Reserve [MW]	390
	Primary Control Time [sec]	30
	Activation of Primary Control (Deadband) ⁸ [mHz]	±20
	Secondary Reserve minimum duration [min]	20
	<i>Recommended Technical Standards</i>	
()	Accuracy of frequency measurement (for regulation) [mHz]	10
	Accuracy of MW measurement of the Tie lines (for ACE control) [%]	1-2

Notes:

§	To be updated when significant changes occur in the Synchronous Area .
*	To be calculated periodically on regular basis.
()	Values in brackets are taken from the National Grid Code of one of the Grid Operators of the Synchronous Area . They shall be considered as tentative values.
£	Values are taken from studies conducted by WAPP
[a]	Optional, to be defined and agreed upon by the Grid Operators of the same Synchronous Area
B	Terms in Bold are defined in the Glossary and Definitions

Table OC 2 reports the resulting primary reserve and network frequency characteristic taken from a study conducted by **WAPP**.

Table OC 2. Reference values for main LFC parameters characterizing a Synchronous Area.

Area	Contribution coefficient	Minimum Primary Reserve [MW]	Minimum Network Power Frequency Characteristic [MW/Hz]
TCN	53%	205	1025

⁷ As per OC 3.3.3, the **Reference Incident** is the maximum instantaneous power deviation between **Generation** and **Demand** that could happen in the un-split **Synchronous Area** to be handled by **Primary Control** starting from undisturbed **Functional Operation**. It shall be calculated for each **Synchronous Area** based on the results of appropriate studies, which shall be updated by the **SMO** from time to time.

⁸ See Connection Code 5.3.5 for requirements on power-frequency regulation for **Generation Units**.

CEB	3%	11	54
NIGELEC	1%	4	18
SOGEM	1%	4	19
GRIDCo	19%	75	375
CIE	14%	55	275
SONABEL	2%	8	38
EDM-SA	2%	8	38
SENELEC	6%	22	108
TOTAL	100%	390	1950

A.2 Under Frequency Load Shedding (UfLS)

Table OC 3 reports a typical **UfLS** plan.

Table OC 3. Reference values for Default UfLS plan.⁹

TYPICAL LOAD SHEDDING ARRANGEMENT				
49.8	Special threshold	Pumping Load only	Condition	Objective
49.2 (*)	Allowed first step	Pumping Load exhausted	No more pumping Load to be shed	
49.0 (**)	1 st Mandatory step	Shed 5% of total consumption at least		
48,8	2 nd step	Shed no more than 10% of total Load		Compensate loss of Generation
48,6	3 rd step	Shed no more than 10% of total Load		
48,4	4 th step	Shed no more than 10% of total Load		
48,2	5 th step	Shed no more than 10% of total Load		
48,0 (***)	6 th step	Shed no more than 10% of total Load		
< 48.0	Steps for national needs			

NOTES

(*) lower than the Max Instantaneous Frequency Deviation

(**) to be lower than the Max Instantaneous Frequency Deviation with sufficient margin.

(***) at the final mandatory level, the cumulative demand to be disconnected with the 6 steps shall be 45% of the total Load at national level.

Hypothesis at max step of 200 mHz

Max disconnection time: 350 milliseconds

No intentional delay should be set.

RECOMMENDED TECHNICAL STANDARDS

UfLS max limit of operation 120-140% of the nominal voltages (to avoid overvoltage)

UfLS min limit of operation 20-60% (to avoid unwanted shedding due to non-significant measures).

The underfrequency relay shall guarantee an accuracy equal or better than ± 10 mHz.

⁹ These are the values prescribed by the Central Europe Synchronous Area (ENTSO-E) under EU Operation Guidelines.

ANNEX B – PROPOSED TEST PROCEDURE FOR THE PRIMARY CONTROL OF THE GENERATION UNITS

The aim of these proposed procedural tests is to establish a rapid diagnosis of the contribution from the **Generation Units** to the **Primary Control**, using existing means at the level of the **Control Centres**. These tests should make it possible to classify the generating units into three (3) categories:

- a) Category 1: **Generation Unit**, which participates in the **Primary Control** and whose parameters comply with the **REM Codes**.
- b) Category 2: **Generation Unit**, which participates in the **Primary Control**, but whose parameters do not comply with the **REM Codes**.
- c) Category 3: **Generation Unit** which does not participate in **Primary Control**.

The necessary means are as follows:

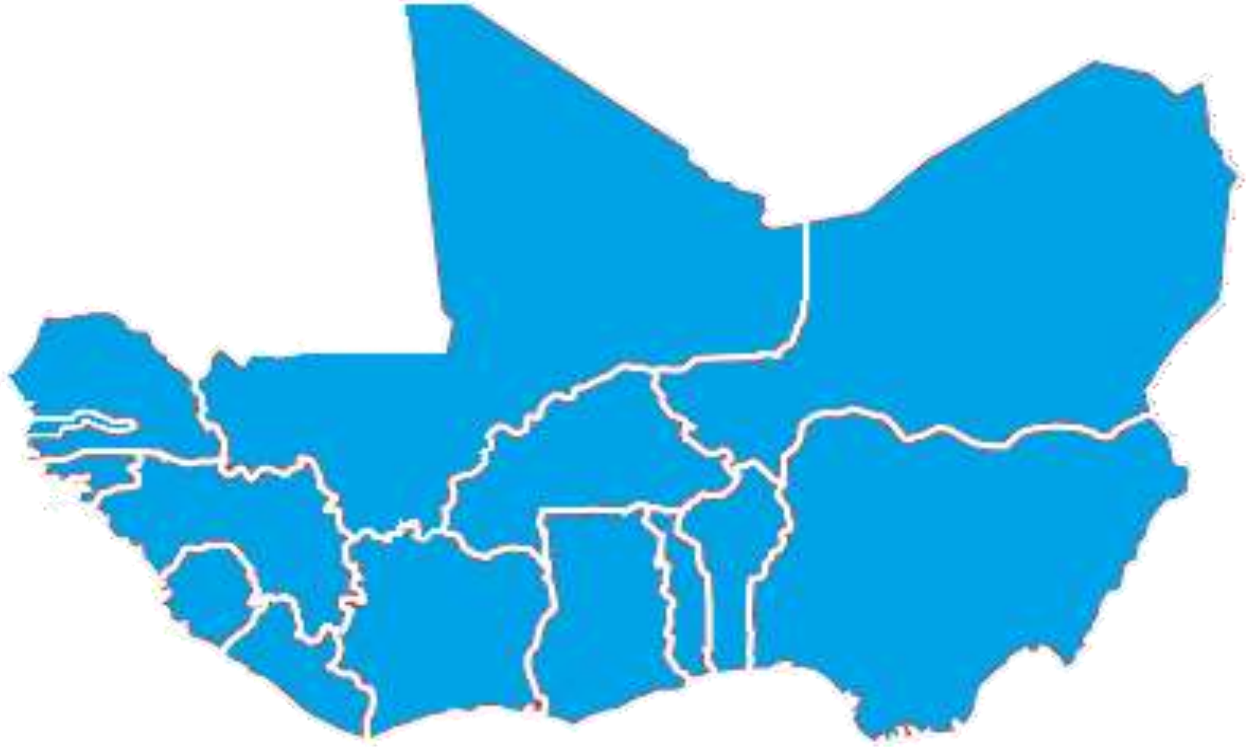
- a) At the **Control Centre** level:
 - i. The frequency measurement with an accuracy of 10 mHz and with a sampling of 1 second.
 - ii. The measurement of the active power (P) for the **Generation Unit** tests, with a precision in relation to the **Generation Capacity** of the **Generation Unit** and with a sampling of one (1) second preferably or less than or equal to five (5) seconds.
 - iii. The synchronisation of these measurements in order to be able to establish behavioural relationships.
 - iv. Data storage for a **Day** or at least for several hours.
 - v. The possibility of being able to record the variations in active power **Generation** of the **Generation Units**, the frequency and values of active power transmission on the International Interconnections lines for thirty (30) minutes, in the event of an incident in the interconnected **WAPP Power System**.
- b) The **Information** stored shall be provided in a standard format, such as Excel, so the available data can be easily analysed.

The data collected will make it possible, by comparing the active **Generation** of the **Generation Units** and the variation in frequency, to estimate the following quantities:

- a) The participation in **Primary Control**,
- b) The value of **Frequency Response Deadband**,
- c) The **Generation Unit** droop,
- d) The power frequency characteristic of the **Generation Unit**,
- e) The power frequency characteristic of the **Control Area**,
- f) The **Network Power Frequency Characteristic** of the entire **Synchronous Area**

Depending on the results, the **Generation Facility** shall correct the deficiency as per requirements of the **Connection Code**, unless it is a case subjected to any derogation, as per requirements reported in the **General Conditions** and/or **Connection Code**.

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



CC – CONNECTION CODE

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CC 1. SCOPE OF APPLICATION

CC 1.1.1 The rules and values of all the parameters set in this **Connection Code** are the result of a process of consultation among all the relevant stakeholders. Each **Grid Operator** shall ensure that the provisions of its **National Grid Code** comply with the **Connection Code**, in accordance with the compliance process set out in the **General Conditions**.

CC 1.1.2 The **Connection Code** shall apply to the following areas:

- a) the operational characteristics and performance of the **Grids** from HV inclusive upwards¹ at the **Connection Points** (CC 2);
- b) the procedure for the connection of **Generation Facilities**, **HVDC Systems**, and **Demand Facilities** to the **Grids** (CC 3);
- c) the connection requirements that are common for all **Generation Facilities**, **HVDC Systems** and **Demand Facilities** (CC 4);
- d) the minimum technical requirements necessary for the design criteria and operational capabilities of:
- e) **Generation Facilities** (CC 5);
- f) **HVDC Systems** (CC 6);
- g) **Demand Facilities** (CC 7);
- h) a set of guidelines for the definition of connection requirements for **Distributed Generation** (CC 8).

CC 1.1.3 It is hereby established that all the provisions set out in this **Connection Code** with reference to “**Generation Facilities**” include **Generation Facilities** using **Renewable Energy Sources (RESs)**. However, the specific requirements for **Generation Facilities** using **Variable Renewable Energy Sources (VRESs)** are specified as those for “**Inverter-based Generation Units**”, noting that **VRESs** are usually connected through power electronics to the **Network** (e.g., wind, solar). Table CC 1 outlines all the requirements included in this **Connection Code** that apply to **RES-based Generation Units** connected to the **Transmission System**.

CC 1.1.4 Specifically, the requirements of this **Connection Code** apply to the **Generation Facilities**, **HVDC Systems**, and **Demand Facilities** that meet the following criteria:

- a) **Facilities** that are not connected to the **Transmission System** as of the date of adoption of this **Connection Code**;
- b) **Facilities** subject to significant modifications or partial/total reconstruction after the date of adoption of this **Connection Code**.

¹ As per definition of the term **Network** in the **Glossary and Definitions**, it is considered HV any voltage above 35 kV, inclusive, as per analysis of the EN 50110-1 / EN 50160 / EN 60038 / IEC 60071-1 / EN 61936-1.

- CC 1.1.5 For existing **Generation Facilities**, **HVDC Systems**, and **Demand Facilities** which does not fall under the provisions of CC 1.1.4, each **Grid Operator**, in consultation with the **National Regulatory Authority (NRA)**, shall develop a methodology to enforce the requirements of this **Connection Code**.
- CC 1.1.6 The transition towards full compliance with this **Connection Code** shall be handled on a case-by-case basis by each **Grid Operator** in consultation with the **NRA**, based on the self-assessment of the **Grid Operator** as per Chapter GC 9 of the **General Conditions**, and monitored by the **SMO** and **WAPP**.
- CC 1.1.7 Each **Grid Operator** shall analyse the peculiarities of the **Facilities** connected to its **Power System** and agree with each **Facility Owner** a possible roadmap to achieve compliance with the requirements included in this **Connection Code**, taking into account the contracts in force, the technical capabilities of the **Facilities**, the results of a cost-benefit analysis, and the potential criteria to share the costs. The results of these roadmaps shall be reflected in the **Addendum to the Inter-Grid Operators Agreement**, in accordance with the provisions of the **General Conditions**. The derogation instrument, as per Chapter GC 9 of the **General Conditions**, can be considered in this process.
- CC 1.1.8 Each **Grid Operator** shall ensure that, the methodology developed pursuant to CC 1.1.5 as well as the criteria applied for the cost-benefit analysis are included in its **National Grid Code**.
- CC 1.1.9 With reference to CC 1.1.4b) , each **Grid Operator** shall, upon consultation with the **NRA**, develop a non-exhaustive list of modifications that shall be deemed significant², which shall be approved by **ERERA**. In the case of a **Facility** for which there are significant modifications or partial/total reconstruction, the **Grid Operator** shall evaluate the significance of a modification or reconstruction based on information that are communicated by the **Generation Facility Owner**, **HVDC System Owner** and **Demand Facility Owner** to the **Grid Operator**. The **Grid Operator**, upon consultation with the **NRA**, shall define a time period from receipt of the communication within which it will make a determination as to whether or not the modification constitutes a significant modification or reconstruction. After this period, in the absence of a communication from the relevant **NRA** or **Grid Operator**, the modification or reconstruction shall be considered not significant.
- CC 1.1.10 The cases in which, due to the modification to a **Facility**, it is necessary to update the contract referred-to in CC 3.2.5 between the **Grid Operator** and the **Facility Owner** shall be considered significant modifications, with consequent application of the rules as referred-to in this **Connection Code**.

² A non-exhaustive list of changes that shall be deemed as significant considers the following: for **Synchronous Generation Units**: replacement of synchronous machine, renewal of voltage and/or frequency control equipment and of protection or control systems, change/replacement of thermal or hydraulic components. For **Inverter-based Generation Units**: replacement of wind turbines or inverters for a cumulative power of at least 10% of **Nominal Power**, replacement of control equipment. For **HVDC Systems**: change in transfer capacity, technology or configuration (monopolar, bipolar).

CC 1.1.11 In relation to **Generation Facilities**, it is hereby specified that the relevant requirements apply directly to all the **Generation Units**, both **Synchronous Generation Units** and **Inverter-based Generation Units**, connected to the **Transmission System** with voltage levels equal or higher than 132 kV or having a **Nominal Power** equal to or higher than 10 MW. Requirements for **Generation Units** connected to the **Network** at a voltage level below 132 kV or having a **Nominal Power** below 10 MW and above 100 kW are specified in CC 8 for **Distributed Generation**. Each **Grid Operator**, in consultation with the **NRA**, may establish specific thresholds for **Nominal Power** and voltage levels, above which **Generation Facilities** connected to the national **Transmission System** shall be required to comply without prejudice to the provisions of this **Connection Code**.

CC 1.1.12 The requirements that govern the deployment of frequency and voltage regulation by the **Grid Operator** through the participation and contribution of **Generation Facilities** are stipulated in the **Operation Code**.

CC 1.2 Rules applicable to Renewable Energy Sources (RES)

CC 1.2.1 **RES-based Generation Units** may be divided into two main categories:

- (i) synchronous technologies usually programmable such as geothermal and some hydro **Units**;
- (ii) (ii) DC-connected technologies usually non-programmable such as photovoltaic or wind **Units**.

CC 1.2.2 In this **Connection Code**, **RES** based on synchronous technologies are considered in the category of "**Synchronous Generation Unit**". On the contrary, **RES** based on DC-connected technologies are included in the category of "**Inverter-based Generation Unit**", which, by definition, means a unit or ensemble of units which is either non-synchronously connected to the **Network** or connected through power electronics. The latter also include battery energy storage. Unless otherwise specified, as per CC 1.1.11, the requirements applicable to the **Facilities** mentioned as "**Generation Units/Generation Facilities**" include directly also all the **RES-based Generation Units**.

CC 1.2.3 For the sake of clarity, the following Table CC 1 outlines all the requirements included in this **Connection Code** that apply to **RES-based Generation Units** connected to the **Transmission System**.

Table CC 1. Summary of all the requirements that apply to RES-based Generation Units connected at the Transmission System.

Requirements		Ref. in Connection Code	Generator
ES	Frequency ranges	CC 5.1.1	
	Rate of change of frequency withstand capability	CC 5.2.2	
	Control of Target Active Power	CC 5.3.2	

	Limited frequency sensitive mode — over-frequency (LFSM-O)	CC 5.3.4	  
	Limited frequency sensitive mode — under-frequency (LFSM-U)	CC 5.3.4	  
	Frequency Sensitive Mode (FSM)	CC 5.3.5	  
	Frequency restoration control	CC 5.3.6	  
	Monitoring of FSM	CC 5.3.5.7	  
	Synthetic inertia capability	CC 5.3.7	 
VS	Voltage ranges	CC 5.1.2	  
	Fault Ride Through Capability	CC 5.2.1	  
	Reactive power capability at maximum capacity	CC 5.4.1.1	  
	Reactive power capability below maximum capacity (synchro)	CC 5.4.1.2.1	
	Supplementary reactive power capability	CC 5.4.1.3	  
	Reactive power capability below maximum capacity (inverter-based)	CC 5.4.1.2.2 to CC 5.4.1.2.4	 
	Voltage Control Modes (AVR)	CC 5.4.2.1 to CC 5.4.2.2	
	Voltage Control Modes (inverter-based)	CC 5.4.2.3	 
	Short Circuit Contribution	CC 5.4.3	 
MPS	Synchronization and Re-synchronization	CC 5.5.1	  
	Ramping Limits	CC 5.5.2	  
	Protection Systems	CC 5.5.3	  
	Control Systems	CC 5.5.4	  
	Priority Ranking of Control and Protection Actions	CC 5.5.5	  
	Priority to active or reactive power contribution	CC 5.5.6	 
	Power Quality	CC 5.5.7	  
	Simulation Models	CC 5.5.8	  
MES	Black Start	CC 5.6.1	  
	Load-rejection and Quick Re-Synchronization	CC 5.6.2	  
	Remote control for Defence Plan Participation	CC 5.6.3	  
IE	Monitoring and Information Exchange	CC 5.7	  

FS: Frequency Stability requirements

VS: Voltage Stability requirements

MPS: Management of the Power System requirements

MES: Management of Emergency Situation requirements

IE: Information Exchange requirements



= Hydroelectric Unit and any generic RES Unit synchronously connected to the Grid



= Photovoltaic (PV) and Wind Units, and any generic RES Unit not-synchronously connected to the Grid

CC 2. OPERATIONAL CHARACTERISTICS AND PERFORMANCE OF THE GRIDS AT THE CONNECTION POINTS

CC 2.1.1 The **Grid Operator**, in consultation with the **National Regulatory Authority**, shall define the operational characteristics and performance of the respective **Grid** at the **Connection Points**. Accordingly, on an annual basis, the **Grid Operator** shall review and publish information pertaining to the operational characteristics and performance of the respective **Grid**.

CC 2.1.2 The **Grid Operator** shall guarantee the operational characteristics and performance of the respective **Grid** at the **Connection Points** upon their definition. **Generation Facilities, HVDC Systems**, and **Demand Facilities** shall contribute to maintaining the performance of the **Grid** by complying with the technical rules of this **Connection Code**.

CC 2.2 Operating Condition

CC 2.2.1 Provisions concerning the **Operating Condition** are provided in the **Operation Code**.

CC 2.3 Frequency Ranges

CC 2.3.1 Each **Grid Operator** shall ensure that the nominal frequency in its **National Grid Code** is set at 50 Hz, consistent with the **WAPP Interconnected Transmission System (WAPPITS)**

CC 2.3.2 Each **Grid Operator** shall provide the **Grid Users** with any data and information on the frequency ranges within which the frequency can vary for each **Operating Condition**, based on the requirements stated in OC 3.4 of the **Operation Code**, and these values shall be indicated in its **National Grid Code**.

CC 2.4 Voltage Level

CC 2.4.1 Each **Grid Operator** shall declare the nominal and the operating voltage ranges within which the voltage can vary for each **Operating Condition** for each **Connection Point**, based on the requirements stated in OC 3.4 of the **Operation Code** and these values shall be indicated in its **National Grid Code**.

CC 2.5 Other Voltage Characteristics

CC 2.5.1 The **Grid Operator** shall define the following voltage characteristics applicable to the normal **Operating Conditions**:

- a) **Total Harmonic Distortion (THD):**

The **Grid Operator** shall define the maximum expected value of the **THD** expressed in percentage for each nominal voltage level of the respective **Grid**. The limits for **THD** shall be those specified on the standard given in ANNEX A – REFERENCE STANDARDS.

b) Unbalance of the three-phase voltages:

The **Grid Operator** shall define the maximum expected degree of unbalance of the three-phase voltages for each **Connection Point**. The degree of unbalance is usually defined by the ratio, in percentage, of the absolute value of the negative sequence voltage component to the absolute value of the positive sequence component, obtained by the transformation of the unbalanced 3 phase voltage quantities in the 3 symmetrical components (positive, negative, and zero sequences)³. The value of maximum unbalance shall be less than 1%.

Exceptional conditions that may result in higher values can be considered by the **Grid Operator** such as phase interruption.

c) Flicker:

The **Grid Operator** shall define the maximum value for short-term flicker severity (P_{st}) and long-term flicker severity (P_{lt}) of each nominal voltage level of its **Grid**. The standards for P_{lt} and P_{st} are given in ANNEX A – REFERENCE STANDARDS

d) Voltage sags and swells:

The **Grid Operator** shall define the maximum expected yearly number of voltage sag and swell events for each **Connection Point**. The parameters, such as a decrease/increase of Root Mean Square (RMS) voltage and duration, characterizing these events shall be in line with the up-to-date applicable standard. The number of voltage sags or swells occurring in each **Connection Point** may vary in the range of tens to hundreds in a year. Variability depends, among others, on the specific position of the **Connection Point**, on short-circuit current, and on voltage level.

CC 2.5.2 During **Planning** of their **Grids**, the **Grid Operators** shall coordinate to adopt the same limits of **THD**, unbalance and flicker based on the available reference technical documentation, being the technical reports, technical specifications, or international standards, issued by a recognized international standards organization.

CC 2.6 Short-Circuit Current

CC 2.6.1 The **Grid Operator** shall calculate and notify the **Grid User** the maximum and minimum expected values of short-circuit current for each **Connection Point**:

- a) during the connection process set out in CC 3.2, in order to identify and design the **Network System for the Connection**;
- b) periodically, on an annual basis, to assess and update these values.

³ The decomposition method is based on the Fortescue's Theorem.

CC 2.6.2 The procedure for the computation of the maximum and minimum short-circuit current shall be published by the **Grid Operator**, according to the standard given in ANNEX A – REFERENCE STANDARDS.

CC 2.6.3 The approach for determining the maximum and minimum values of short-circuit current shall be harmonized among **Grid Operators** within the same **Synchronous Area**.

CC 3. CONNECTION PROCESS

CC 3.1 General Conditions for Connection

CC 3.1.1 Any **Entity** that proposes to interconnect a **Facility** to the **Grid** of a **Member State** or increase the capacity of an already-connected **Facility** shall request to be connected in accordance with the connection process indicated in this CC 3.

CC 3.1.2 Each **Grid Operator** shall incorporate the requirements included in this connection process in a dedicated procedure for connecting **Generation Facilities**, **HVDC Systems** and **Demand Facilities** to its **Transmission System**.

CC 3.1.3 At the effective date of the **REM Codes**, the procedure for requesting connection shall be made publicly available by the **Grid Operator**. Any updates to the procedure shall be made public prior to enforcement.

CC 3.1.4 The procedure for connection shall involve the following parties:

- a) the **Generation Facility Owner** or the **HVDC System Owner** or the **Demand Facility Owner**, as applicant for the connection;
- b) the **Grid Operator** according to the national regulation as:
 - i. the relevant **Entity** in charge of evaluating the applications for connection;
 - ii. the grantor of the authorization to connect;
 - iii. the **Entity** that defines, in cooperation with the relevant **Transmission Operator**, the techno-economic conditions for obtaining the access and interconnections to the **Relevant Grid**.
- c) **SMO**, as support provider to the **Grid Operator** upon request.

CC 3.1.5 The procedure shall detail the formal steps needed for being connected to the **Grid** of the **Grid Operator** and the related timing. The procedure shall cover the following phases:

- a) Authorization phase.
- b) Realization phase.

- c) Entry-into-service phase.

CC 3.2 Phase 1: Authorization

CC 3.2.1 The authorization phase shall commence with a request by an applicant which triggers a connection impact study by the **Grid Operator**. Prepayment for the study is required and is based on estimates by the **Grid Operator** on an individual request basis. The applicant may withdraw its request for connection at any time during the study process upon written notice to the **Grid Operator**; however, such withdrawal shall not relieve the applicant of study costs incurred or committed to be incurred by the **Grid Operator**. A request for connection shall be deemed complete once the completed application and appropriate prepayment have been received.

CC 3.2.2 Request for Connection

CC 3.2.2.1 At the time of submitting a request for connection, the applicant shall attach a connection study agreement form, which shall be made publicly available by the **Grid Operator**, pursuant to which the applicant agrees to reimburse the **Grid Operator** for the actual cost of the connection impact study. The request for connection shall include a list of documents that cover, but not limited to, the following information:

- a) the company profile of the applicant;
- b) the proposed **Connection Point** and details on the site of connection;
- c) the certified technical documentation and data related to the **Facility**, relevant to the connection to the **Grid**;
- d) the commencement and end date of the works to build the **Facility** and the expected date the said **Facility** will come into operation;
- e) the details of the technical capabilities of the **Facility**, relevant to the connection to the **Grid**;
- f) evidence of compliance with the connection requirements set out in the relevant **National Grid Code** and/or relevant national regulation and/or national standards.

CC 3.2.2.2 With reference to CC 3.2.2.1 b), the Table CC 2 below shall, based on **Good Utility Practices**, provide indicative **Nominal Power** ranges of **Generation Facilities** and **Demand Facilities** for connection to the **Transmission System** on the different voltage levels of the **Connection Point**.

Table CC 2. Indicative Nominal Power ranges for connection to the Transmission System on the different voltage levels of the Connection Point.

	Range of Nominal Power [MW]	Voltage level at the Connection Point [kV]
Generation	< 10	MV
	10 – 30	> 35 up to 90 (or the minimum HV level in the country)
	30 – 100	132 – 161
	100 – 350	225 – 330

	> 350	330 – 400
Demand	< 10	MV
	10 – 30	> 35 up to 90 (or the minimum HV level in the country)
	30 – 100	132 – 161
	> 100	225 – 330 – 400

CC 3.2.3 **Connection Impact Study**

CC 3.2.3.1 The **Grid Operator** shall conduct the connection impact study upon receipt of:

- (i) an application for connection;
- (ii) the signed connection study agreement, which specifies the **Grid Operator's** estimated cost of the connection impact study and the applicant's cost share for that study;
- (iii) the required prepayment for the estimated connection study cost by the applicant.

CC 3.2.3.2 Each **Grid Operator** shall be responsible for conducting the connection impact study either by itself or by subcontract.

CC 3.2.3.3 For the purpose of conducting the connection impact study, the applicant shall provide any additional information as may be requested by the **Grid Operator**.

CC 3.2.3.4 The **Grid Operator** shall conduct the connection impact study within ninety (90) business days from the date of signature of the connection impact study agreement, and it shall determine, at least, the following conditions:

- a) the technical feasibility of interconnecting the proposed **Facility** to the **Grid** at the selected **Connection Point**;
- b) identification of any network reinforcements and/or expansions that would be required in the **Grid** to make the integration of the **Facility** feasible at the identified **Connection Point**;
- c) all the infrastructure that would be required to connect the proposed **Facility** to the **Grid**;
- d) switchgear rating for the **Facility** at the **Connection Point** and the coordination of protections;
- e) the estimates of the total cost and the cost to be allocated to the applicant for the infrastructure, network reinforcements and/or expansions needed to accommodate the connection request evaluated in the connection impact study.

CC 3.2.4 **Comprehensive Facility Study**

CC 3.2.4.1 Where the connection impact study finds that the impact on the **Grid** is acceptable, the **Grid Operator** shall, through a facility study agreement, authorise the comprehensive facility study which shall determine at a minimum:

- a) the conditions of acceptance by the **Grid Operator**;
- b) the necessary modifications to the original connection project, if any;
- c) the general technical solution for the connection, constituting the **Network System for the Connection**.
- d) the timeline to develop and provide the applicant with the **Network System for the Connection** including the executive design phases for the work.
- e) technical specifications on **Metering**, specifying the responsibilities pertaining to the **Metering** service of the electricity produced, input and withdrawn;
- f) technical specifications on the communication and monitoring system such as the **Remote Terminal Unit (RTU)** and any other device for remote monitoring to be implemented by the applicant at its expense as per request of the **Grid Operator**;
- g) any activity that must be carried out parallel to the connection;
- h) the estimate of the connection costs for the **Network System for the Connection** and system upgrades needed to accept power into the **Grid** at the **Connection Point** that are necessary to accommodate connection of the **Facility** evaluated in the study;
- i) the preliminary completion date by which the **Facility** and **Network System for the Connection** are expected to be ready for connection to the **Transmission System**.

CC 3.2.4.2 To retain the assigned priority of its connection request, the applicant shall execute and return the said facility study agreement within fifteen (15) days, by which the applicant shall accept or reject the connection estimate or request changes and agree to reimburse the **Grid Operator** for the actual cost of the detailed facility study. In the absence of any acceptance or request of changes by the applicant within the aforementioned period, the connection application shall be considered automatically expired.

CC 3.2.4.3 The **Grid Operator** shall, within ninety (90) business days from the receipt of the Facility Study Agreement, develop and provide to the applicant the detailed facility study, which shall include the **Network System for the Connection**, the related connection costs with a complete breakdown of cost components as well as the indication of the cost, calculated according to the criteria set by the **Grid Operator** and made publicly available, and the time required to complete the construction of the **Network System for the Connection** .

CC 3.2.4.4 The detailed technical solution for the connection shall be the reference document for the executive planning and construction of the **Network System for the Connection**.

CC 3.2.5 **Connection Contract**

CC 3.2.5.1 Upon completion of the detailed facility study, the **Grid Operator** shall offer to the applicant a connection contract, to be executed by the applicant and the **Grid Operator**. The connection contract shall:

- a) include the results of the detailed facility study;
- b) specify the terms and conditions regarding the connection of the **Facility** or any equipment to the new **Connection Point** in the **Grid**;
- c) indicate whether the construction of the **Network System for the Connection** will be handled by the **Grid Operator** or by the applicant;
- d) set out the expected connection date;
- e) define the **Metering** scheme to be used to **Meter** the **Facility**.

CC 3.2.5.2 To retain the priority assigned to its connection request, an applicant shall execute and return the connection contract to the **Grid Operator** within sixty (60) days of the receipt of the contract. During this time period, the approved connection application and related connection estimate with general technical solution for the connection elaborated by the **Grid Operator**, as referred to in CC 3.2.4.1, shall remain valid and the **Grid Operator** shall book and assign to the **Facility** its hosting **Grid** capacity.

CC 3.2.5.3 Within sixty (60) days from the date the connection contract was offered by the **Grid Operator**, the applicant shall submit a social and environmental impact assessment for the proposed **Facility** and obtain all permits necessary for the construction of the **Facility**. Depending on the local regulatory framework, the characteristics of the **Facility** and the primary energy source, the procedures for permits may involve one or more stakeholders and the applicant shall ensure that all permits necessary for the building, installation and operation of the **Facility** are obtained.

CC 3.2.5.4 At the time the applicant submits to the **Grid Operator** the executed connection contract referred to in CC 3.2.5.2, an acceptable environmental and social impact assessment report, and the proof that all the necessary permits for the construction have been obtained, the applicant shall provide the **Grid Operator** with a form of financial security acceptable to the **Grid Operator**. Such financial security shall be in an amount equivalent to the estimated costs determined by the **Grid Operator** in the connection contract.

CC 3.2.5.5 Where an applicant fails to timely execute the connection contract or provide the financial security prescribed in CC 3.2.5.4, its connection request shall be deemed to have lapsed or been withdrawn. A lapse or withdrawal of a connection request shall not relieve the applicant of the obligation to reimburse the **Grid Operator** for the actual costs incurred prior to such lapse or withdrawal.

CC 3.3 Phase 2: Realisation

CC 3.3.1 Upon the execution of the connection contract referred to in CC 3.2.5 by the parties, and the payment of the connection charges, construction of the **Network System for the Connection** may commence. The construction works shall be completed within the time frame specified in the connection contract.

CC 3.3.2 Once all the civil and electrical works of the **Facility** and the **Network System for the Connection** have been completed and the **Facility** is ready for entry-into-service, the **Grid Operator** shall perform an on-site inspection to check that the **Facility** has been constructed and installed according to the documentation provided by the **Facility Owner** in phase 1 of the connection process, in compliance with this **Connection Code** and applicable standards.

CC 3.3.3 In case of **Generation Facilities**, in addition to the on-site inspection as per CC 3.3.2 above, the **Grid Operator** shall request the **Generation Facility Owner** to submit a compliance study, which shall include:

- a) Load flow study to demonstrate the capacity of the installation vis-à-vis the requirements of supply / absorption of reactive power;
- b) Short-circuit study to assess the contribution of the installation to short-circuit currents;
- c) Protection studies;
- d) **Fault-Ride-Through** capability dynamic studies to demonstrate the capacity of the production installation to remain connected to the **Grid** and to supply reactive current to the **Connection Point** during faults;
- e) Power quality studies to verify the potential transfer of disturbances affecting the power quality, as per CC 5.5.7;

CC 3.4 Phase 3: Entry-into-service

CC 3.4.1 The **Grid Operator** shall define an operational notification procedure that entitles a **Generation Facility Owner** or an **HVDC System Owner** or a **Demand Facility Owner** to start-up and operate its **Facility**. This procedure shall comprise the following stages:

- a) the definition and signing of the **Operational Agreement** with the **Grid Operator** for each new **Facility** to be connected to the **Grid**. The **Operational Agreement** shall:
 - i. define the respective responsibilities with regards to the operation and control of the **Facility** and system sections which are functional to the **Relevant Grid**;
 - ii. define the characteristics of the **Facility** and processes, as well as specific connection requirements, in addition to those given in this **Connection Code** and in the relevant national regulation, if deemed necessary;

- iii. define the relations between the **Grid Operator** operating units of the **Control Centre(s)** and the **Grid User's** personnel, and any third parties;
 - iv. consider any derogation to the requirements of this **Connection Code**, according to the rules stated in GC 9 of the **General Conditions**.
- b) Operational notification to authorise the relevant **Facility Owner** to energize its internal electrical network and auxiliaries and connect to the **Connection Point**.
 - c) Operational notification to authorise the relevant **Facility Owner** to operate its system connected to the **Grid** for a limited period as defined by the **Grid Operator**, necessary to assess at least the technical data of the system and the compliance with requirements.
 - d) Operational notification to authorise the relevant **Facility Owner** to operate its system connected to the **Grid** at the **Connection Point**. This operational notification shall be issued by the **Grid Operator** upon prior removal of all incompatibilities identified for the purpose of CC 3.4.1 c) above.

CC 4. GENERAL REQUIREMENTS

CC 4.1.1 The general requirements shall apply, without discrimination, to **Generation Facilities, HVDC Systems** and **Demand Facilities** as per CC 1. The specific requirements for **Generation Facilities, HVDC Systems** and **Demand Facilities** are given in CC 5, CC 6, and CC 7, respectively.

CC 4.2 Preliminary Provisions

CC 4.2.1 The connection of the **Generation Facilities, HVDC Systems** and **Demand Facilities** to the **Grid** shall not cause any degradation in the performance or reliability of the **Grid** and shall contribute to the safety and quality of the service according to the capabilities of the **Facility** and the **Power System** and in the modalities detailed in each relevant chapter of this Connection Code.

CC 4.2.2 The design of the **Network System for the Connection** shall be executed such that it shall not adversely affect the operation of the **Grid** or damage the other **Facilities**.

CC 4.2.3 Respective materials and components of **Generation Facilities, HVDC Systems** and **Demand Facilities** shall be designed and manufactured in compliance with the prevailing national and international standards on safety and protection of people and properties.

CC 4.3 Facility and Connection Site Documentation

CC 4.3.1 For each **Connection Site**, the technical reference documentation shall be prepared by the applicant and the **Grid Operator** for the appropriate management of the **Connection Site**.

CC 4.3.2 The **Generation Facility Owner**, the **HVDC System Owner**, and the **Demand Facility Owner** shall be responsible for the drafting, updating and formal communication to the **Grid Operator** of the technical documentation for its **Facility** that shall comprise:

- a) single-line diagram and layout plan;
- b) technical specifications, manuals and test data for each equipment;
- c) schemes and descriptions of control, operation, metering and protection equipment and systems.

CC 4.3.3 Upon request, the **Facility Owner** shall provide the **Grid Operator** with the technical plant documentation, in electronic format and in formats defined by the **Grid Operator**, limited to those parts of the plant that have influence on the **Functional Operation** of the **Grid**.

CC 4.3.4 For every **Connection Site**, the **Grid Operator** shall keep the list of the technical characteristics of the site. The **Grid Operator** shall be responsible for the development and update of the list, based on the information provided by the **Grid User**. The main subjects covered by the documentation of the technical characteristic of the **Connection Site** are the following:

- a) Indicative performance of the **Grid** at the **Connection Point** as per CC 2.
- b) Characteristics of **Facilities**:
 - i. **Grid Facilities**:
 - coordination of the insulation relating to the delivery substation;
 - characteristics of the protection system at the delivery substation.
 - ii. **Grid User's Facility**:
 - list and location of the circuit breakers controlled remotely by the protection systems of the **Grid** or by the **Grid Operator's** devices;
 - characteristics of the tap changers of the HV/MV or EHV/MV transformers of the **Grid User**;
 - deployment and location of devices for load reduction, if any;
 - deployment of automatic devices for introducing and removing reactive power compensation reserves, if any;
 - a list of any **Element** belonging to the **Grid Operator** which are installed in the **Grid User's Facility**.
 - iii. Connection lines:
 - coordination of insulation;
 - characteristics of circuit breakers and disconnectors;
 - **Metering System** and protection systems.
- c) Operation, management and control of the **Facilities** as referred to in CC 4.3.4.b):

- i. management of multiple **Connection Points** and the emergency power supplies which involve the parallel connection of distinct parts of the **Grid**;
- ii. characteristics of the telecommunication systems;
- iii. any certification for the **Facility** to participate in the provision of **Ancillary Services**;
- iv. choice of unavailability periods of parts of the **Facility**;
- v. access to the **Facility** and procedures for carrying out works;
- vi. Safety for people and property during maintenance interventions.

CC 4.3.5 All the technical documentation, data and information referenced herein, including remote signals, remote metering, remote controls, remote regulations, and operational relations shall be cohesively included in the **Operational Agreement**, together with the information concerning the performance of the **Facilities** and the processes of electricity production.

CC 4.4 Schemes for Connection to the Grid

CC 4.4.1 The **Grid Operator**, shall ensure that the procedure for the identification of the technical solution for the connection of the **Generation Facility**, the **HVDC System** and the **Demand Facility** to the **Grid** is included in its **National Grid Code**.

CC 4.4.2 As a minimum, the procedure shall consider the following steps:

- a) admission of connection to the **Grid** based on the size of the **Facility** and definition of the connection voltage level;
- b) identification of the **Connection Point** and technical configuration of the insertion in the **Grid**;
- c) definition of switching devices and the **Network System for the Connection**;
- d) definition of functional and property limits.

CC 4.5 Protection Systems

CC 4.5.1 The design and operation of **Generation Facilities**, **HVDC Systems** and **Demand Facilities** shall take into account the technical features and performance of the **Grid** protection system. Accordingly, the **Operational Agreement** shall report the requirements for the protection system.

CC 4.5.2 The protection system for **Generation Facilities**, **HVDC Systems** and **Demand Facilities** shall:

- a) guarantee the following general criteria:
 - i. coordination with **Grid** protection system;

- ii. backup protection where needed;
 - iii. monitoring;
 - iv. contribution to identification of faults.
- b) be organized according to:
 - i. protection at **Connection Point**;
 - ii. protection against faults that are outside the **Generation Facility, HVDC System and Demand Facilities**;
 - iii. protection against faults that are inside the **Generation Facility, HVDC System and Demand Facilities**;
 - iv. protection of connection lines between **Connection Point** and the **Grid** (when present).

CC 4.5.3 The **Operational Agreement** shall define the settings of protection equipment.

CC 4.6 Communication System

CC 4.6.1 The **Generation Facility, HVDC System and Demand Facility** shall be integrated into the **SCADA**, both in real-time and in deferred time, of the **Grid**. This is achieved by exchanging data and information between the **Generation Facility, HVDC System, Demand Facility** and the **Facilities** owned and controlled by the **Grid Operator**.

CC 4.6.2 The **Generation Facility Owner**, the **HVDC System Owner**, and the **Demand Facility Owner** are required to provide measurements and signals to the **Grid Operator** and to the **SMO** through the **Grid Operator**, to ensure:

- a) the real-time observability of the **Facility** itself and the functions of **Physical Operation** of the **Power System**, as per details in articles CC 5.3.5.7, CC 5.3.6.2 and CC 5.7.1 for **Generation Facilities**, in article CC 6.8.3 for **HVDC Systems**, and in article CC 7.6.2 for **Demand Facilities**; and,
- b) the availability of historical operation data and performance of the **Facility** itself in deferred time.

CC 4.6.3 The **Grid Operators** shall be equipped with the appropriate devices capable of transferring the measurements and signals provided by **Facility Owners** to the **SMO** as per Article CC 4.6.2.

CC 4.6.4 The **Grid Operator** shall:

- a) define the detailed list of data, data formats, communication protocols and interfacing modes that must be compatible with its own control system; and,
- b) guarantee the compatibility of their own control systems to standard products such as standard formats, protocols and interfacing modes.

CC 4.6.5 **Grid Users** shall comply with the requirements set by the **Grid Operators** as per CC 4.6.4.a) concerning the communication system. Further details on information exchanges between the **Grid Operator** and **Generation Facilities**, **HVDC Systems**, and **Demand Facilities** are in CC 5.7, CC 6.8, and CC 7.6 respectively.

CC 4.6.6 The **Grid Operator** may require the **Generation Facility Owner**, the **HVDC System Owner**, and the **Demand Facility Owner** to install dedicated equipment for remote control. Such request shall be evaluated on a case-by-case basis by the **Grid Operator**, and agreed upon with the **Facility Owner** during the authorization phase of connection process specified in CC 3.2.4.1 and reported in the **Operational Agreement**.

CC 4.7 **Derogation**

CC 4.7.1 The **Grid Operator** may, upon the request of a **Generation Facility Owner**, an **HVDC System Owner** or a **Demand Facility Owner**, grant derogations from specific provisions of the **Connection Code** in accordance with its **National Grid Code**. Such derogations may apply to existing or prospective **Generation Facility**, an **HVDC System** or a **Demand Facility** in accordance with the compliance and monitoring process set out in GC 9 of the **General Conditions**, and the criteria for granting derogations published by the **Grid Operator** on its website.

CC 4.7.2 Where a **Generation Facility Owner**, an **HVDC System Owner** or a **Demand Facility Owner** is unable to comply with any provision of the **Connection Code**, it shall, without delay, report such non-compliance to the **Grid Operator** and request for a derogation from such provision.

CC 4.7.3 Each **Grid Operator** shall set a procedure to govern the process for request, analysis and evaluation of a derogation in accordance with its national regulatory framework.

CC 4.7.4 A derogation to the **Connection Code** relating to any provisions contained therein shall be approved by the relevant **National Regulatory Authority** based on a proposal by the **Grid Operator**. The **Grid Operator** has the right to grant only temporary derogations to certain provisions of the **Connection Code** only if the operational security of the national **Power System** will be compromised by the application of the same provisions.

CC 4.7.5 In the procedure referred to in CC 4.7.3, the **Grid Operator** shall define the list of minimum information that a **Facility Owner** shall include within its request for derogation. The information to be provided by the **Facility Owner** shall identify at least the provision which the **Facility Owner** is unable to comply with, the technical reason(s) for the non-compliance requiring derogation, and the expected effect on the **Relevant Grid** and cross-border electricity exchanges.

CC 4.7.6 The derogation procedure shall define:

- a) the process to be followed by the **Grid Operator** in evaluating the derogation requests and issuing the decision;

- b) the timeline for the process; and,
- c) the conditions under which a decision granting a derogation may be revoked.

CC 4.7.7 The **Grid Operator** shall:

- a) keep a register of all derogations which have been granted.
- b) on request from a **Facility Owner**, provide a copy of the register limited to the **Facility Owner's** own derogation requests.

CC 5. REQUIREMENTS FOR GENERATION FACILITIES

CC 5.1 Operating Ranges

CC 5.1.1 *Frequency Ranges*

CC 5.1.1.1 All **Generation Units** shall be designed, built and operated to be capable of remaining connected to the **Grid** within the frequency ranges, and minimum duration specified in Table CC 3 according to the following scheme:

- a) one range around the nominal frequency of the **Synchronous Area** with unlimited duration of operation;
- b) one or more ranges with frequency below the nominal frequency of the **Synchronous Area** with limited duration of operation as per Table CC 3;
- c) one or more ranges with frequency above the nominal frequency of the **Synchronous Area** with limited duration of operation as per Table CC 3.

CC 5.1.1.2 In defining the duration referenced in Table CC 3 in the **National Grid Code**, the **Grid Operator** and its **National Regulatory Authority** shall consider the applicable international standards for products on frequency-related capabilities.

CC 5.1.1.3 The **Grid Operator** and the **Generation Facility Owner** may mutually agree on wider frequency ranges, longer minimum duration of operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a **Generation Unit**, if it is needed to preserve or to restore **Grid** security. The **Generation Facility Owner** shall not unreasonably withhold consent to such request(s) provided it is economically and technically feasible.

Table CC 3. Minimum duration for which a Generation Unit must be capable of operating for frequency deviating from the nominal value of the Synchronous Area without disconnecting from the Grid.

Frequency range	Duration of operation
47.5 Hz – 48.5 Hz	≥ 30 minutes

48.5 Hz – 49.0 Hz	≥ 30 minutes and not less than the period for the range 47.5 Hz – 48.5 Hz
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	30 minutes
51.5 Hz – 52.5 Hz	≥ 1 second

CC 5.1.2 **Voltage Ranges**

CC 5.1.2.1 All **Generation Units** shall be designed, built and operated to be capable of remaining connected to the **Grid** within the ranges of the voltage at the **Connection Point** in accordance with the following scheme:

- a range around the nominal voltage with unlimited duration of operation;
- one or more ranges with voltage below the nominal value with limited duration of operation as defined in Table CC 4.
- one or more ranges with voltage above the nominal value with limited duration of operation as defined in Table CC 4.

CC 5.1.2.2 The **Grid Operator** and the **Generation Facility Owner** may mutually agree on wider voltage ranges, longer minimum duration of operation or specific requirements for combined frequency and voltage deviations (simultaneous overvoltage and underfrequency or simultaneous undervoltage and over-frequency) to ensure the best use of the technical capabilities of a **Generation Unit**, if it is needed to preserve or to restore **Grid** security. The **Generation Facility Owner** shall consent to such request(s) provided it is economically and technically feasible.

CC 5.1.2.3 For the **Generation Units** with a **Nominal Power** higher than 10 MW and connected to the **Transmission System** with a voltage lower than 132 kV – i.e. 90 kV, 69 kV, 66 kV, 63 kV, 55 kV, 36 kV –, each **Grid Operator** shall agree, with the **Generation Facility Owner**, on voltage ranges at the **Connection Points** at which the **Generation Unit** shall be designed, built and operated to be capable of remaining connected to, if those voltage ranges are relevant for maintaining **Operational Limits**.

Table CC 4. Minimum duration for which a Generation Unit must be capable of operating for voltages deviating from the reference 1 pu value (Nominal Voltage for pu calculation is given in the first column) at the Connection Point without disconnecting from the Grid.

Nominal value [kV]	Voltage range [p.u.]	Duration of operation
132, 150, 161, 225	0.85 pu – 0.90 pu	60 minutes
	0.90 pu – 1.118* pu	Unlimited
	1.118 pu – 1.15 pu	[20 - 60] minutes
330, 400	0.85 pu – 0.90 pu	60 minutes

	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	[20 - 60] minutes

*But not beyond 245 kV as per IEC 60038

CC 5.2 Immunity to Grid Disturbances

CC 5.2.1 *Fault-Ride-Through Capability*

CC 5.2.1.1 In case of transient voltage variations due to faults on the **Grid**, **Generation Units** shall be capable of remaining connected to the **Grid** and continue to operate in a stable manner, in the following conditions during a symmetrical fault:

- a) Over a low-voltage **Fault-Ride-Through** voltage-against-time profile for **Synchronous Generation Units**. The **Grid Operator** shall specify the parameters that define each point of the low-voltage **Fault-Ride-Through** within the ranges set out in Table CC 5 valid for **Synchronous Generation Units**. The area above the low-voltage **Fault-Ride-Through** profile represents the minimum area in which the **Synchronous Generation Unit** shall guarantee the connection to the **Grid** in a stable manner. In the area below the low-voltage **Fault-Ride-Through** profile, the disconnection of the **Synchronous Generation Units** due to the intervention of the protection system as referred-to CC 5.5.3 is acceptable.
- b) In-between a low voltage and high-voltage **Fault-Ride-Through** voltage-against-time profiles for **Inverter-based Generation Units**. The **Grid Operator** shall specify the parameters that define each point of the low- and high-voltage **Fault-Ride-Through** profiles within the ranges set out in Table CC 6 valid for **Inverter-based Generation Units**. The area in-between the low- and high-voltage **Fault-Ride-Through** profiles represents the minimum area in which the **Inverter-based Generation Unit** shall guarantee the connection to the **Grid** in a stable manner. In the area below the low-voltage **Fault-Ride-Through** profile and above the high-voltage **Fault-Ride-Through** profile, the disconnection of the **Inverter-based Generation Units** due to the intervention of the protection system as referred-to CC 5.5.3 is acceptable.

Table CC 5. Low-voltage Fault-ride-through profile and parameters of a Synchronous Generation Facility. It is expressed as the phase-to-phase voltages on the Transmission System voltage level at the Connection Point during a fault as a function of time before, during and after the fault.

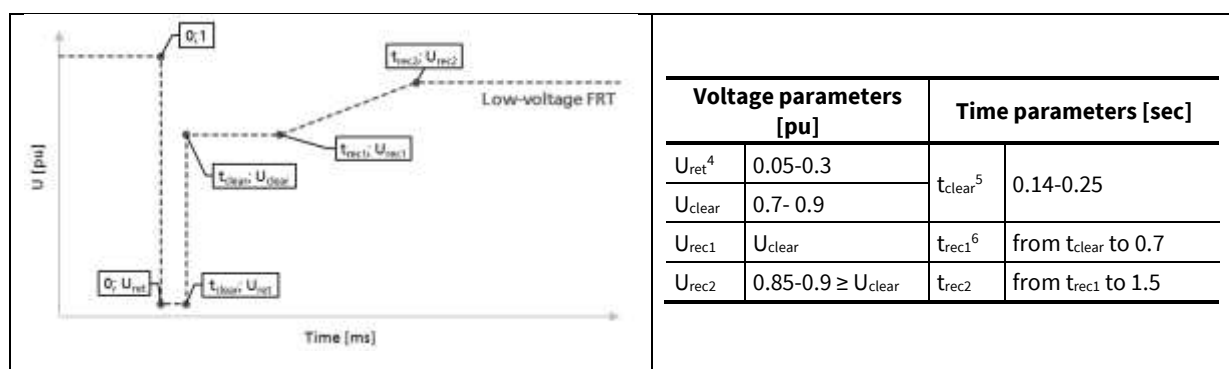
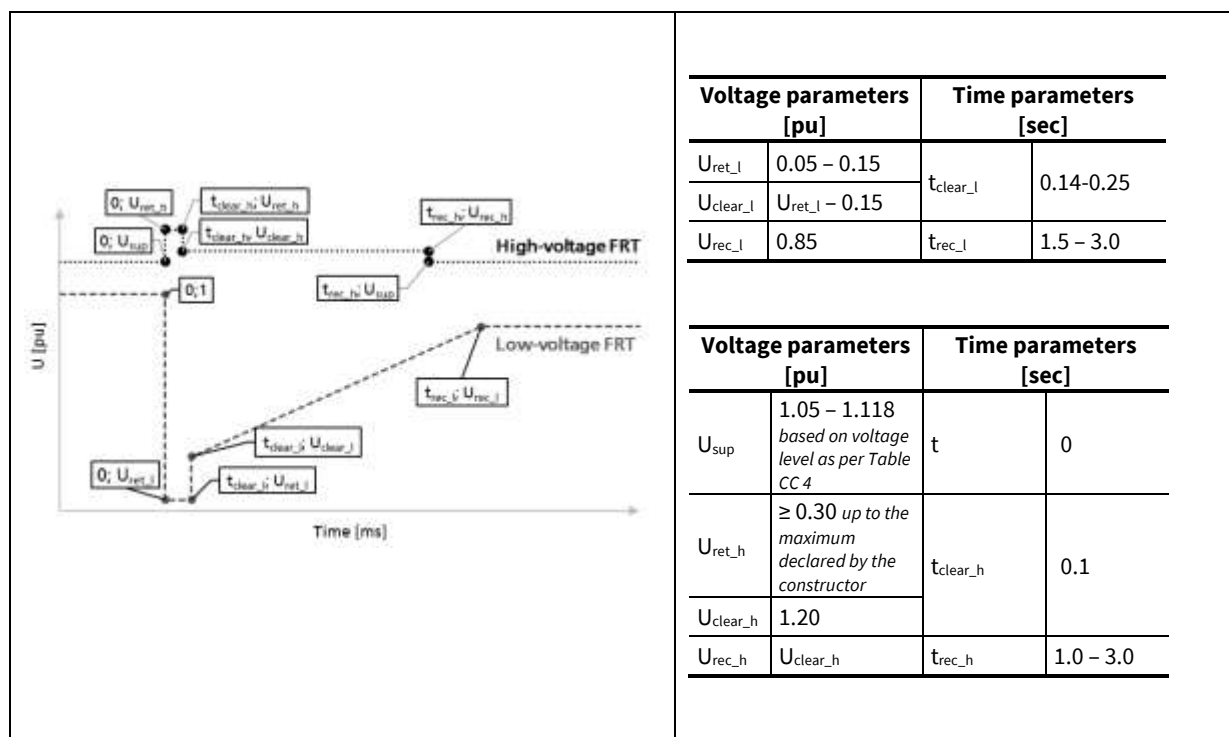


Table CC 6. Low- and high-voltage Fault-ride-through profiles and parameters of an Inverter-based Generation Facility. It is expressed as the phase-to-phase voltages on the Transmission System voltage level at the Connection Point during a fault as a function of time before, during and after the fault.



CC 5.2.1.2 The installation of ad-hoc undervoltage protection devices that traces and implements the described **Fault-Ride-Through** voltage-against-time profiles shall not be permitted. In

⁴ U_{ret} is the retained voltage at the Connection Point during a fault.

⁵ t_{clear} is the instant when the fault has been cleared.

⁶ the subscript “rec” stands for “recovery”, and it identifies certain points of lower limits of voltage recovery after fault clearance.

particular, the under-voltage protection shall be set by the **Generation Facility Owner** according to the technical limits of the **Generation Units**, unless the **Grid Operator** requests other settings.

CC 5.2.1.3 **Generation Units** shall comply with the **Fault-Ride-Through** voltage-against-time profiles for any pre-fault or post-fault value of short-circuit power between the minimum and maximum values of the short-circuit current expected at the **Connection Point**⁷.

CC 5.2.1.4 The **Fault-Ride-Through** requirement shall not apply to the disconnection from the **Transmission System** imposed by operating conditions and/or **Transmission System** protection that shall be implemented through equipment and related parameters defined by the **Grid Operator**.

CC 5.2.1.5 In case of asymmetrical faults, the **Fault-Ride-Through** capabilities shall be specified by each **Grid Operator**. A criterion may follow the one-out-of-three logic: the disconnection for asymmetrical faults can be performed when one of the three voltage levels exceeds the same permitted voltage limits displayed in the profile of Table CC 5 and Table CC 6 defined for symmetrical faults.

CC 5.2.2 ***Rate-of-change-of-frequency withstand capability***

CC 5.2.2.1 A **Generation Unit** shall be capable of staying connected to the **Transmission System** and operating at rates of change of frequency up to 2.5 Hz/s computed over a 5 cycle-time window, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection.

CC 5.3 **Stability and Control of the System Frequency**

CC 5.3.1 This section CC 5.3 of the **Connection Code** provides rules on the technical capabilities and related requirements that each **Generation Unit** shall guarantee to the **Grid Operator** on the matter of frequency regulation. The definition of **Primary Reserve**, **Secondary Reserve**, and **Tertiary Reserve** and related frequency control management obligations are detailed in OC 8 of the **Operation Code**, being operational areas to be coordinated at regional level.

CC 5.3.2 ***Control of Target Active Power***

CC 5.3.2.1 A **Generation Unit** shall have the capability to maintain a constant output at any value of target active power according to the instructions issued by the **Grid Operator** between the declared minimum and maximum active power output, except where the power output follows the changes specified in CC 5.3.3, CC 5.3.4, and CC 5.3.5 of this **Connection Code**.

CC 5.3.2.2 The values of maximum error within which the control system of **Generation Units** shall control the active power with respect to constant target values and during changes in the target value shall not be higher than $\xi_1=1\%$ and $\xi_1=5\%$, respectively, as displayed in Figure CC 1.

⁷ Refer to CC 2.6 for short-circuit current values.

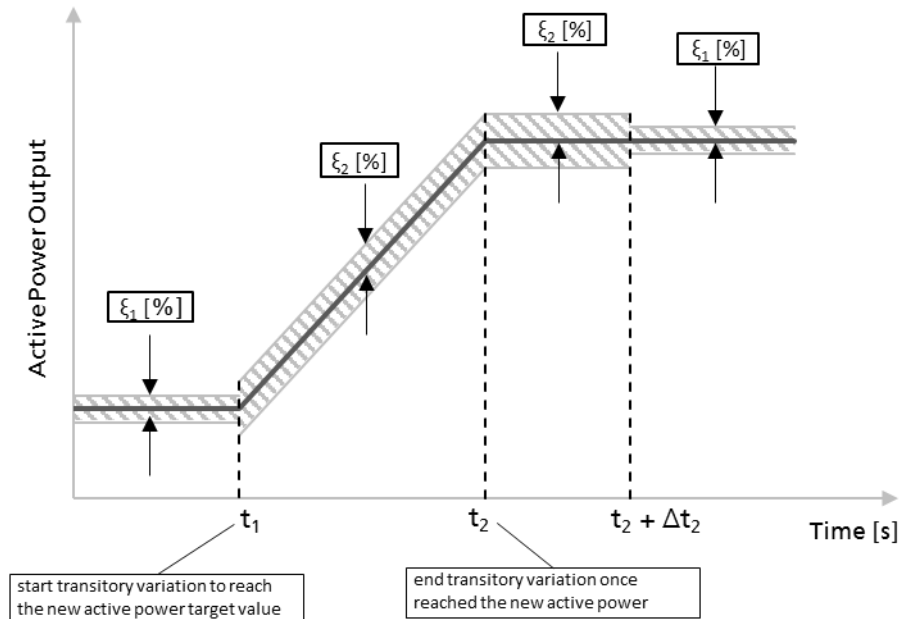


Figure CC 1. Representation of admissible tolerance between the actual active power of the Generation Unit measured as average per second and the reference target value. The parameters ξ_1 and ξ_2 values of maximum error within which the control system of Generation Units must control the active power with respect to constant target values (ξ_1) and during changes in the target value (ξ_2).

CC 5.3.3 Effects of Ambient and Operating Conditions on the Active Power Capability

CC 5.3.3.1 When a **Synchronous Generation Unit** is operating in under-frequency condition, a reduction in the maximum active power declared to the **Grid Operator** is allowed provided such reduction is supported by proven technical justifications.

CC 5.3.3.2 In compliance with the limits provided in article CC 5.3.3.4, each **Grid Operator** shall define the maximum admissible reduction of active power output for under-frequency conditions in its **LFC Area** expressed as a percentage of the **Generation Capacity** of the **Synchronous Generation Unit**. The **Generation Capacity** of the **Synchronous Generation Unit** minus this defined maximum admissible percentage reduction gives the lower limit on the active power capability above which the maximum active power that can be supplied by **Generation Units** must always remain.

CC 5.3.3.3 The admissible active power reduction from the maximum output may vary from **Generation Unit to Generation Unit**, for instance gas-turbine or combined cycle **Synchronous Generation Units** are more sensitive to operation on underfrequency conditions than the other **Synchronous Generation Units**). Therefore, in defining the admissible active power reduction from the maximum output, the **Grid Operator** shall:

- specify the ambient conditions applicable; and,
- take into account the technical capabilities of **Synchronous Generation Units**.

CC 5.3.3.4 The admissible active power reduction from maximum output in under-frequency conditions to be specified by each **Grid Operator** for each **Synchronous Generation Units** category shall fall within the limits illustrated in Figure CC 2, according to the following specifications:

- a) For frequencies below 49 Hz falling by a reduction rate of $\Delta P/P_{MAX}$ equal to 2% of the **Generation Capacity**, for instance the maximum active power output, at 50 Hz per 1 Hz of frequency drop;
- b) For frequencies below 49.5 Hz falling by a reduction rate of $\Delta P/P_{MAX}$ equal to 10% of the **Generation Capacity**, for instance the maximum active power output, at 50 Hz per 1 Hz of frequency drop;

CC 5.3.3.5 These limit specifications shall be interpreted as follows: for frequency in the range 49.5 Hz-50 Hz, a **Synchronous Generation Unit** shall not show any reduction in maximum power output. With frequency below 49.5 Hz, the area within which the **Grid Operator** can define the capability is given between the two solid curves displayed in the Figure CC 2.

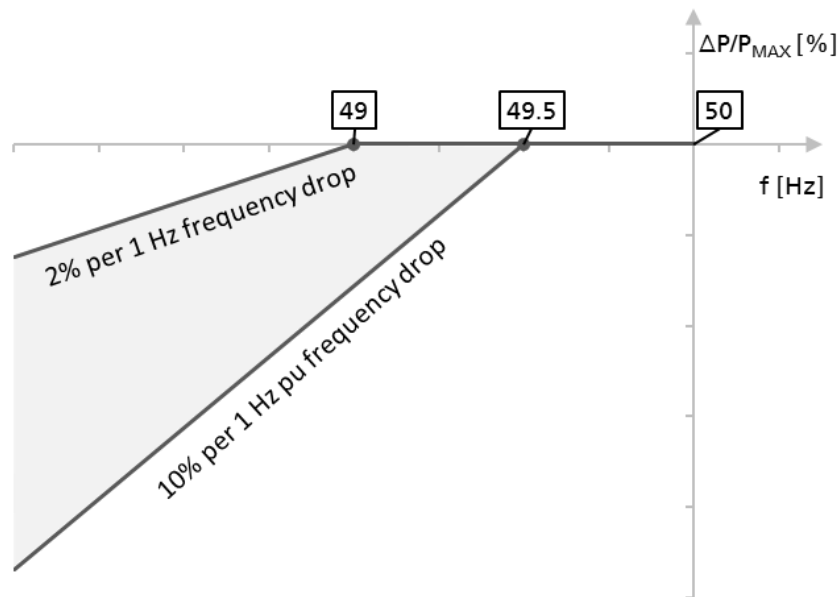


Figure CC 2. Maximum power capability reduction with falling frequency. The percentage value of the reduction refers to the maximum active power of Synchronous Generation Unit.

CC 5.3.4 **Active Power Regulation at Abnormal Over-frequency and Underfrequency**

CC 5.3.4.1 **Generation Units** shall be capable of regulating the active power output in response to wide variations of the frequency in over- and underfrequency according to operating modes referred to as **Limited Frequency Sensitive Mode - Over-frequency (LFSM-O)** and **Limited Frequency Sensitive Mode - Underfrequency (LFSM-U)**.

CC 5.3.4.2 The **Grid Operator** shall define the frequency threshold and droop that characterize **LFSM-O** and **LFSM-U** operating modes in accordance with Figure CC 3 and Figure CC 4 respectively:

- a) P_{ref} is differentiated for **Synchronous Generation Units** and **Inverter-based Generation Units**:
 - i. For **Synchronous Generation Units**, $P_{ref}=P_{MAX}$, which is the **Generation Capacity** of the **Generation Unit**.

- ii. For **Inverter-based Generation Units**, $P_{ref}=P_{MAX}$ or the active power output that is generated by the **Generation Unit** at the moment the **LFSM-O** or **LFSM-U** is reached, as defined by the relevant **Grid Operator**.
- b) ΔP is the variation in the active power production of the **Generation Unit**. f_n is the nominal frequency of the **Transmission System** equal to 50 Hz and $\Delta f = f - f_n$ is the frequency deviation occurring in the **Transmission System**.
- c) in **LFSM-O** as illustrated in Figure CC 3, at over-frequencies where f is greater than f_1^{LFSM-O} , the **Generation Unit** shall provide a negative variation of active power production according to a droop setting equal to s_2 . The **Grid Operator** shall specify the frequency threshold f_1^{LFSM-O} between 50.2 Hz and 50.5 Hz inclusive, and the droop s_2 setting between 2% and 12%. The **Generation Facility Owner** shall set its **Generation Unit** accordingly.
- d) in **LFSM-U** as illustrated in Figure CC 4, at under-frequencies where f is lower than f_1^{LFSM-U} , the **Generation Unit** shall provide a positive variation of active power production according to a droop equal to s_2 . The **Grid Operator** shall specify the frequency threshold f_1^{LFSM-U} between 49.8 Hz and 49.5 Hz inclusive, and the droop s_2 setting between 2% and 12%. The **Generation Facility Owner** shall set its **Generation Unit** accordingly.

CC 5.3.4.3 The “ANNEX B – FURTHER SPECIFICATIONS ON LFSM-O/LFMS-U CALCULATION” provides further specifications and an example of the calculation of **LFSM-O** and **LFSM-U**.

CC 5.3.4.4 The accuracy of frequency measurement by the **Generation Unit** shall comply with the applicable standard in the **Electricity Supply Industry (ESI)** and in any case not greater than 1/100th of Hz (± 0.01 Hz or 10 mHz).

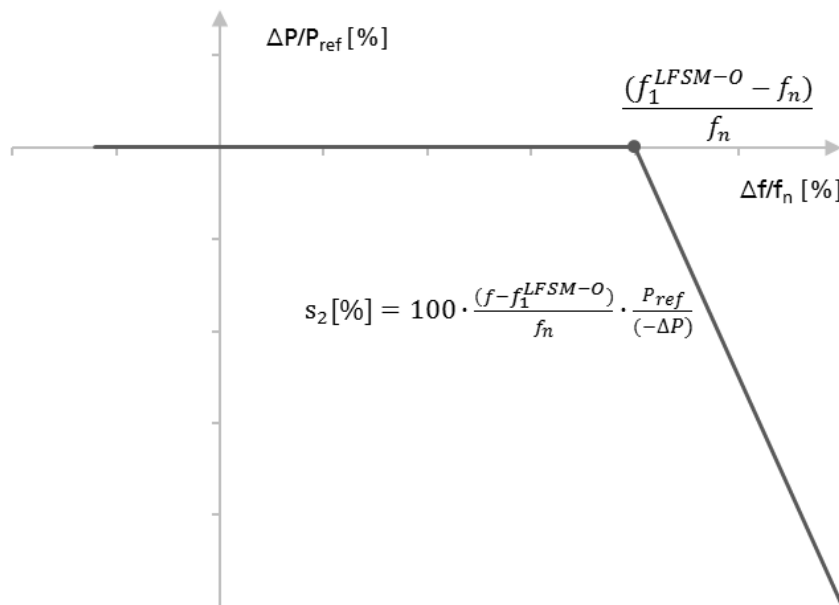


Figure CC 3. Active power frequency response capability of Generation Units in LFSM-O mode.

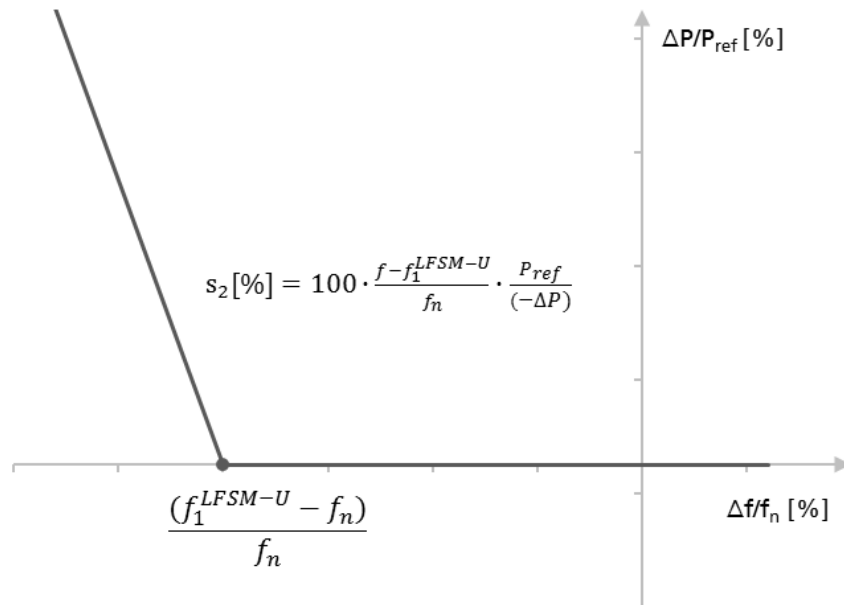


Figure CC 4. Active power frequency response capability of Generation Units in LFSM-U mode.

- CC 5.3.4.5 A **Generation Unit** shall be capable of activating the power frequency response as fast as technically feasible with an initial delay that shall not be greater than two (2) seconds. The **Generation Facility Owner** shall justify any larger delay by providing technical evidence to the **Grid Operator**. For **Inverter-based Generation Units**, the **Grid Operator** can specify a shorter time than two (2) seconds based on the type of technology, such as Photovoltaic (PV), wind and batteries.
- CC 5.3.4.6 The **Generation Units** shall be capable of operating stably during **LFSM-O** and **LFSM-U** operation.
- CC 5.3.4.7 With reference to the operation in **LFSM-O** mode:
- Generation Units** shall be capable of either continuing operation at the minimum regulating level, or alternatively further decreasing active power output according to the request of the **Grid Operator** until its minimum active power capacity is reached.
 - The **LFSM-O** setpoint shall prevail over any other active power setpoints.
- CC 5.3.4.8 With reference to the operation in **LFSM-U** mode:
- Generation Units** shall be capable of providing a power increase up to their **Generation Capacity**.
 - The actual delivery of active power frequency response shall consider:
 - the operating conditions of the **Generation Unit**, in particular limitations on operation near **Generation Capacity** at low frequencies and the impact of ambient conditions according to CC 5.3.3; and,
 - the availability of the primary energy sources.
 - The **LFSM-U** setpoint will prevail over any other active power setpoints.

CC 5.3.4.9 The active power variation to be supplied by **Generation Units** within the downwards and upwards margins available for frequency regulation, as per articles CC 5.3.4.7 and CC 5.3.4.8, shall be performed with the maximum admissible gradient for continuous operation of the **Generation Unit**. This gradient shall not compromise the stability of the fuel supply system, thermal processes, or electromechanical cycle of the **Generation Unit**.

CC 5.3.4.10 With reference to article CC 5.3.4.9, each **Grid Operator** shall define the lower threshold beyond which the maximum gradient of active power variation shall be guaranteed by each **Generation Unit**. The thresholds shall be expressed as a percentage of the **Generation Capacity** variation per unit of time and may vary between different **Generation Units**. Table CC 7 contains indicative threshold values based on **Good Utility Practices**.

Table CC 7. Indicative lower threshold values above which the maximum gradient of active power variation should be guaranteed by Generation Units.

Type of Generation Unit	Lower threshold
Conventional steam Generation Unit	Such that it guarantees continuous operation of the Generation Unit and therefore avoids blocking/tripping of the boiler/turbine system
Gas-turbine or combined cycle Generation Unit	13 % of Nominal Power / min
Other Synchronous Generation Units	3 % of Nominal Power / min
Photovoltaic Generation Units	≤ 2 s for supplying all the available reserve margin in that moment
Wind Generation Units	• ≤ 10 s for supplying all the available reserve margin in that moment, if the latter is lower than 50% of the Nominal Power • ≤ 30 s for supplying all the available reserve margin in that moment, if the latter is higher than 50% of the Nominal Power

CC 5.3.4.11 **LFSM** operating mode requirements may be adapted to such **Generation Units** that do not have the intrinsic capability of regulating the power output with regards to frequency variations due to technology limitations such as **VRESs**-based **Generation Units** not coupled with battery storage systems. Such technology limitations shall be demonstrated by the relevant **Generation Facility Owner** to the **Grid Operator** during the authorization phase of the connection process provided in CC 3. The relevant **National Regulatory Authority** may grant this derogation based

on the communication from the **Grid Operator** and the validity of the demonstration provided by the **Generation Facility Owner**, and in accordance with the rules stated in GC 9 of the **General Conditions**.

CC 5.3.5 **Active Power Response to Normal Frequency Variations**

CC 5.3.5.1 **Generation Facilities** shall have the capability to operate in the **Frequency Sensitive Mode (FSM)**, which determines a variation in the active power output with respect to the programmed value of target active power in response to normal frequency variations of the **Transmission System**.

CC 5.3.5.2 Where a **Generation Unit** does not have the capability to regulate the power output in response to frequency variations due to technology limitations, the relevant **Generation Facility Owner** shall indicate such limitations to the **Grid Operator** during the authorization phase of the connection provided in CC 3. The **Grid Operator** shall thoroughly evaluate the connection of the **Generation Unit** with technology limitation to provide **FSM**, especially when the lack of **FSM** for a **Generation Unit** may be critical for the purpose of maintaining the stability of the **Transmission System** in case of a **Contingency**.

CC 5.3.5.3 The **Grid Operator** shall define the parameters that characterize the **FSM** in accordance with Figure CC 5 and within the ranges shown in Table CC 8, considering that:

- a) P_{ref} is differentiated for **Synchronous** and **Inverter-based Generation Units**:
 - i. For **Synchronous Generation Units**, $P_{ref}=P_{MAX}$, which is the **Generation Capacity** of the **Unit**.
 - ii. For **Inverter-based Generation Units**, $P_{ref}=P_{MAX}$ or the active power output that is generated by the **Generation Unit** at the moment the **FSM** threshold is reached, as defined by the relevant **Grid Operator**.
- b) ΔP is the variation in the active power production of the **Generation Unit**. f_n is the nominal frequency of the **Transmission System** equal to 50 Hz and $\Delta f = f - f_n$ is the frequency deviation occurring in the **Transmission System**.
- c) The **Generation Unit** shall be insensitive to frequency variations in the range of the **Frequency Response Deadband**. In case of frequency variation above the **Frequency Response Deadband**, the contribution of active power not supplied must be recovered according to one of the three coloured schemes represented in Figure CC 5.
- d) The accuracy of frequency measurement shall be compliant with the applicable standard in the **Electricity Supply Industry (ESI)**, and in any case not greater than 1/100th of the Hz (± 0.01 Hz or 10 mHz).
- e) For power levels between the minimum regulating level and the **Generation Capacity** of the **Generation Unit**, the active power variation required by the **Frequency Sensitive Mode (FSM)** shall not be limited in its amplitude unless the **FSM** limit $\Delta P_1/P_{MAX}$ indicated in Table CC 8 or the minimum or maximum active power **Operational Limits** of the **Generation Unit** are reached.
- f) In respecting the previous article CC 5.3.5.3.e), the actual delivery of active power frequency response shall also consider:

- i. the operating conditions of the **Generation Unit**, in particular, limitations on operation near maximum capacity at low frequencies and the impact of ambient conditions according to article CC 5.3.3; and,
- ii. the availability of the primary energy sources.

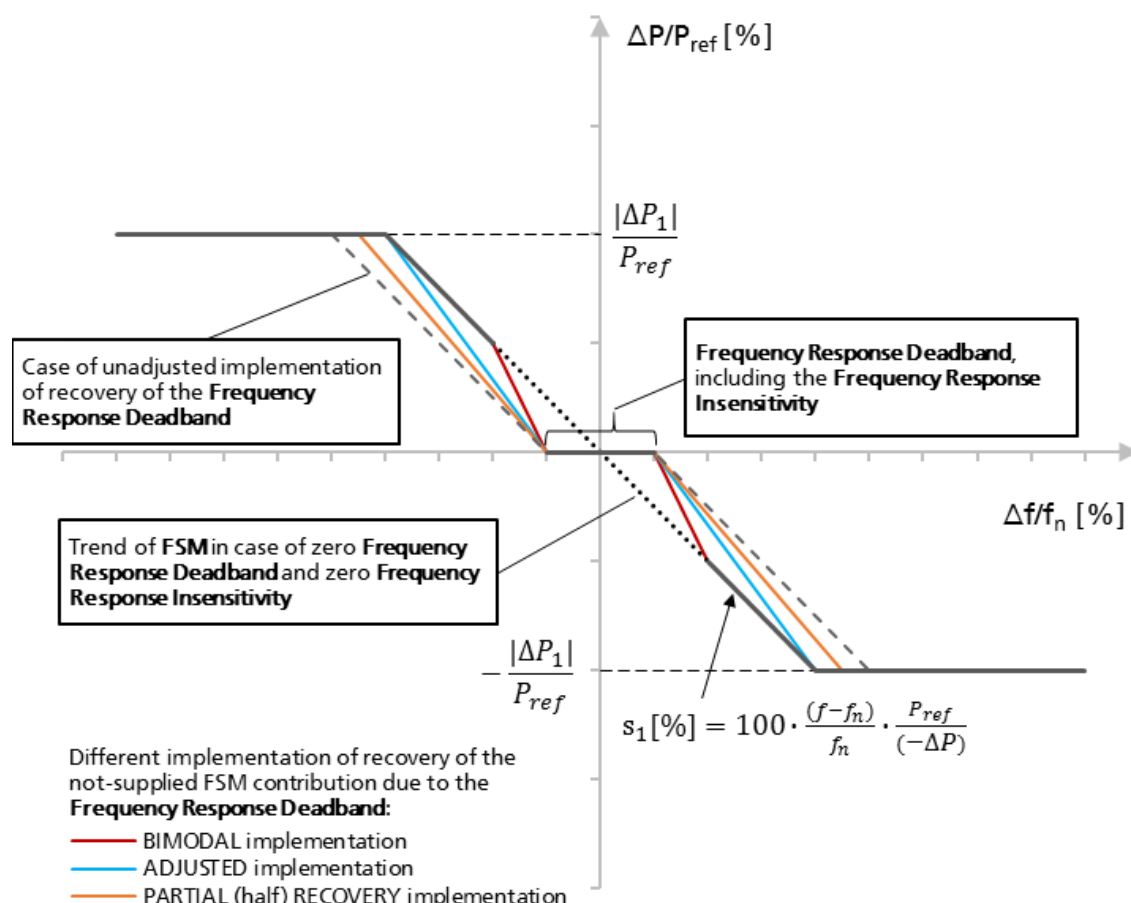


Figure CC 5. Active power frequency response capability of Generation Units in FSM. The figure represents the changes in active power output that a Generation Unit shall be capable of provide according to frequency variations.

Table CC 8. Parameters for active power frequency response in FSM (explanation for Figure CC 5).

Parameters	Ranges
Active power range related to maximum capacity ($\Delta P_1/P_{MAX}$)	1.5 – 10%
Frequency Response Insensitivity of the regulators Δf_i	±10 mHz
Frequency Response Deadband	0 – 500 mHz
Droop s_1	2 – 12%

CC 5.3.5.4 A **Generation Unit** shall have the capability of sustaining the provision of full active power frequency response in a stable manner for a period of between fifteen (15) and thirty (30) minutes consecutively in the absence of further frequency changes, as specified by the **Grid Operator**. In the event of further frequency changes, the **Generation Unit** shall continue to increase or

decrease the power issued on the basis of the frequency deviation Δf occurring in the **Transmission System** and the droop s_1 set.

CC 5.3.5.5 In specifying the period as referred to in article CC 5.3.5.4, the **Grid Operator** shall consider the available active power margin and primary energy source of the **Generation Unit**.

CC 5.3.5.6 In the event of frequency step changes, the **Frequency Sensitive Mode (FSM)** shall be activated by the **Generation Unit** according to a curve in Figure CC 5 or at most in correspondence with the line shown in Figure CC 6 and in accordance with the parameters specified by the **Grid Operator** based on the technology-dependent limitations of the **Generation Units** within the ranges given in Table CC 9. The parameter $\Delta P_1/P_{MAX}$ is same as the one indicated in Table CC 8 to be defined by the **Grid Operators**.

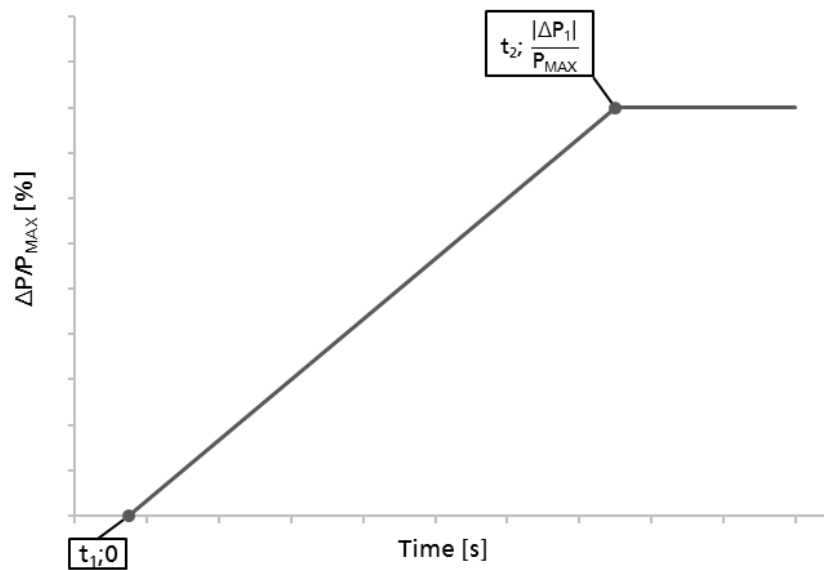


Figure CC 6. Active power frequency response capability of Generation Units the event of frequency step changes.

Table CC 9. Parameters for full activation of active power frequency response resulting from frequency step change (explanation for Figure CC 6).

Parameters	Synchronous Generation Units	Inverter-based Generation Units
t_1 : the maximum admissible initial delay t_1 unless justified otherwise	2 sec	0 sec (intentional)
t_2 : Maximum admissible choice of full activation time t_2 , unless longer activation times are allowed by the Grid Operator for reasons of system stability	30 sec	30 sec

CC 5.3.5.7 In order to monitor the operation of **FSM**, the **Generation Units** shall be capable of transferring, in real-time and in a secured manner, at least the following signals to the **Control Centre** of the **Grid Operator**:

- g) status signal of **FSM** (on/off);
- h) scheduled active power output;

- i) actual value of the active power output;
- j) actual parameter settings for active power frequency response; and,
- k) droop and **Frequency Response Deadband**.

CC 5.3.5.8 The **Grid Operator** shall have the right to request additional data and signals. This request shall be evaluated on a case-by-case basis by the **Grid Operator**, and agreed upon with the **Facility Owner** during the authorization phase of connection process provided in article CC 3.2.4.1 and reported in the **Operational Agreement**.

CC 5.3.6 **Frequency Restoration (or Secondary Control)**

CC 5.3.6.1 All **Generation Units** shall be capable of providing **Secondary Reserve** that is, the **Ancillary Service** that aims at restoring the frequency to its nominal value and at maintaining the **Scheduled Energy Exchanges** of a **Synchronous Area**. The modalities for providing this **Ancillary Service** shall be regulated by the **Grid Operator** during **Functional Operation**.

CC 5.3.6.2 All **Generating Units** participating in the **Secondary Control** shall comply with the following minimum requirements, which may be further specified by the **Grid Operators**:

- l) The speed control devices, in addition to the compliance with the requirements in CC 5.3.4 and CC 5.3.5, shall be capable of receiving the remote command to vary the power reference signal from the centralized **Automatic Generation Control (AGC)** of the **Grid Operator**^{8,9}.
- m) The maximum duration by which **Generation Units** shall be able to provide the full **Secondary Reserve**, shall be less than two hundred (200) seconds.
- n) The definition and communication of the lower threshold above which the gradient of active power variation shall be guaranteed by each **Generation Unit** and calculated as a function of the time constant set in the **AGC** to reduce the **Area Control Error (ACE)** to zero¹⁰, as defined in the **Operation Code**.
- o) The duration for which a **Generation Unit** shall be capable of sustaining the provision of **Secondary Reserve** in a stable manner shall be a minimum of two (2) hours.

CC 5.3.6.3 The **Grid Operators** within the same **Synchronous Area** shall harmonize the requirements of **Secondary Control** functionalities for **Generation Units** under the coordination of the **SMO**.

⁸ The variation is expressed as a percentage value, variable between 0% and 100%, referred to the **Secondary Reserve** available.

⁹ In case of **Generation Facilities** comprising more than one **Generation Unit**, the centralised **AGC** must be equipped with a device capable of sharing the power variations among the regulated **Generation Units**.

¹⁰ For the supply of the secondary reserve to zero the ACE, the central secondary controller of the **Grid Operator** (i.e. the **AGC**) works according to a behaviour over time obtained by assigning a proportional-integral characteristic (PI) to control circuits. The integral part depends on an integration time constant T set in the **AGC**. This requirement **Error! Reference source not found..n**) requires that the power variation gradient of each generator must be not less than the variation speed of the remote control level signal, which is defined by each **Grid Operator** as a function of such integration time constant T set in the **AGC**.

CC 5.3.7 **Synthetic Inertia for Inverter-based Generation**

CC 5.3.7.1 The **Grid Operator** may require that an **Inverter-based Generation Unit** be capable of providing **Synthetic Inertia** in response to rapid frequency deviations.

CC 5.3.7.2 The **Grid Operator** shall specify the operating principle of control systems installed to provide **Synthetic Inertia** and the associated performance parameters.

CC 5.4 **Stability and Control of the System Voltage**

CC 5.4.1 **Reactive Power Capability**

CC 5.4.1.1 *Reactive power capability at **Generation Capacity***

CC 5.4.1.1.1 With regards to reactive power capability at **Generation Capacity**, the **Grid Operator** shall define the $U-Q/P_{MAX}$ -profile, which sets the boundaries within which a **Generation Unit** shall be capable of providing reactive power at its **Generation Capacity**. The $U-Q/P_{MAX}$ -profile shall be defined in accordance with the following principles and in consistence with Figure CC 7:

- a) the dimensions of the $U-Q/P_{MAX}$ -profile envelope shall be within the Q/P_{MAX} range and voltage range specified by the **Grid Operator** within the limits defined in Table CC 10.
- b) the position of the $U-Q/P_{MAX}$ -profile envelope shall be defined by the **Grid Operator** within the limits of a fixed outer envelope defined in Table CC 10.
- c) the **Grid Operator** shall define the above-mentioned profiles for both **Synchronous Generation Units** and **Inverter-based Generation Units**.

CC 5.4.1.1.2 The **Grid Operators** within the same **Synchronous Area** shall harmonize the dimensions of the inner envelope of **Synchronous Generation Units** and **Inverter-based Generation Units** within the limits defined in Table CC 10.

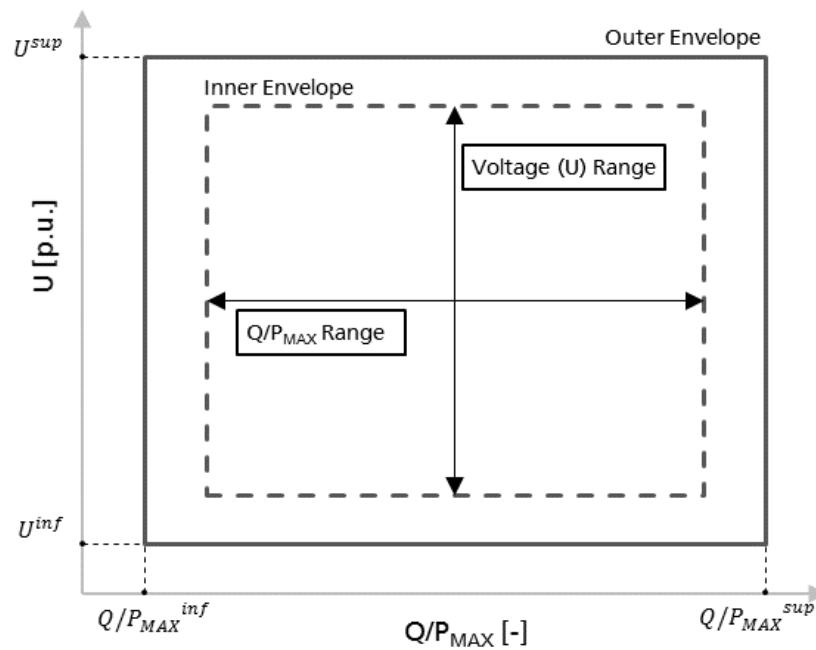


Figure CC 7. U- Q/P_{MAX} -profiles to be defined by the **Grid Operator**.

Table CC 10. Parameters for the inner and outer envelopes in Figure CC 7.

Parameters	Synchronous Generation Units	Inverter-based Generation Units
Definition of Inner Envelope		
Q/P_{MAX} Range [-]	0.95 – 1.08	0.66 – 0.95
Voltage (U) Range [p.u.]	0.150 – 0.225	0.150 – 0.225
Definition of Outer Envelope		
U^{sup} [p.u.]	1.100	
U^{inf} [p.u.]	0.875	
Q/P_{MAX}^{inf} [-]	- 0.500	
Q/P_{MAX}^{sup} [-]	+ 0.650	

CC 5.4.1.1.3 A **Generation Unit** shall be capable of moving to any operating point on the surface within its U- Q/P_{MAX} profile in appropriate timescales to target values requested by the **Grid Operator**.

CC 5.4.1.2 *Reactive power capability at active power below **Generation Capacity***

CC 5.4.1.2.1 **Synchronous Generation Units** shall be capable of operating at every possible operating point in the P - Q -capability diagram of the alternator of **Synchronous Generation Units**, at least down to a minimum stable operating level when operating at an active power output below the **Generation Capacity** ($P < P_{MAX}$).

CC 5.4.1.2.2 With regard to **Inverter-based Generation Units**, the **Grid Operator** shall define a P - Q/P_{MAX} -profile, which sets the boundaries within which an **Inverter-based Generation Unit** shall be capable of providing reactive power below its **Generation Capacity**. The

P - Q/P_{MAX} -profile shall be defined according to the following principles and consistent with Figure CC 8 and Table CC 11:

- the dimensions of the P - Q/P_{MAX} -profile envelope shall be within the Q/P_{MAX} range specified in Table CC 11.
- the active power range of the P - Q/P_{MAX} -profile envelope at zero reactive power shall be 1 p.u. where the reference for the p.u. is the **Generation Capacity** of the **Generation Unit**.
- the P - Q/P_{MAX} -profile can be of any shape and shall include conditions for reactive power capability at zero active power.
- the position of the P - Q/P_{MAX} -profile envelope shall be within the limits of a fixed outer envelope specified in Table CC 11.

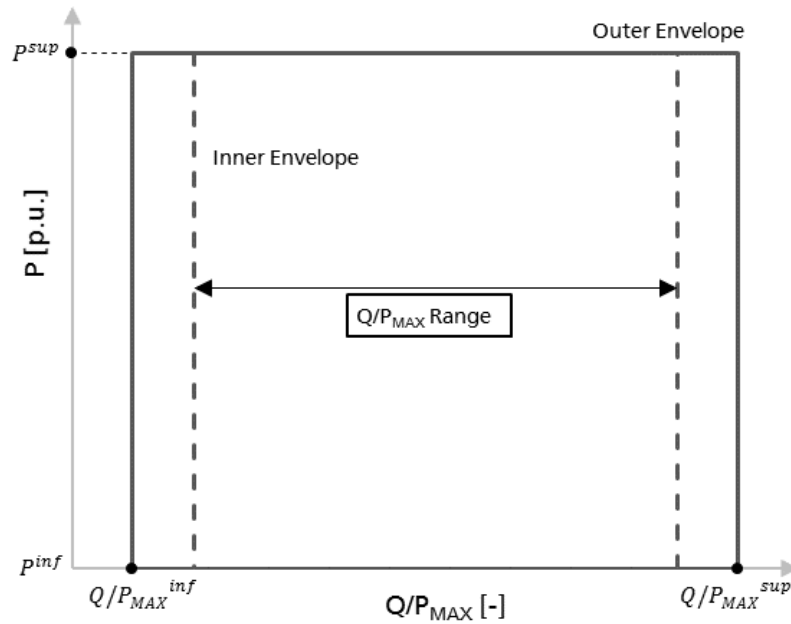


Figure CC 8. P - Q/P_{MAX} -profile to be defined by the **Grid Operator** for Inverter-based Generation Units.

Table CC 11. Parameters for the inner and outer envelopes in Figure CC 8.

Parameters	Inverter-based Generation Units
Definition of Inner Envelope	
Q/P_{MAX} Range [-]	0.66 – 0.95
P Range [p.u.]	1
Definition of Outer Envelope	
p^{sup} [p.u.]	1.000
p^{inf} [p.u.]	0.000
Q/P_{MAX}^{inf} [-]	- 0.500
Q/P_{MAX}^{sup} [-]	+ 0.650

CC 5.4.1.2.3 When operating at an active power output below **Generation Capacity** ($P < P_{MAX}$), the **Inverter-based Generation Unit** shall be capable of providing reactive power at any operating point inside its P - Q/P_{MAX} -profile.

CC 5.4.1.2.4 An **Inverter-based Generation Unit** shall be capable of moving to any operating point on the surface within its P - Q/P_{MAX} profile in appropriate timescales to target values requested by the **Grid Operator**.

CC 5.4.1.3 *Reactive power compensation*

CC 5.4.1.3.1 Where there is a line or a cable connection between the **Connection Point** of the **Generation Facility** and the high-voltage terminals of the step-up transformer, if requested by the **Grid Operator**, the **Generation Facility Owner** shall compensate the reactive power demand of the line or cable connection.

CC 5.4.2 **Voltage Control Modes**

CC 5.4.2.1 **Synchronous Generation Units** shall be equipped with an excitation control system, namely the **Automatic Voltage Regulator (AVR)**, that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of the **Generation Unit**.

CC 5.4.2.2 The parameters and settings of the **AVR** shall be agreed upon by the **Synchronous Generation Facility Owner** and the **Grid Operator**. These parameters shall include:

- a) bandwidth limitation of the output signal;
- b) under- and over-excitation limiter;
- c) a stator current limiter;
- d) a **Power System Stabilizer (PSS)** function to attenuate power oscillations, which includes the specifications on the damping coefficients to be harmonized through dedicated power system studies within the same **Synchronous Area**.

CC 5.4.2.3 **Inverter-based Generation Units** shall contribute to the voltage control through the implementation of the following control modes:

- a) Voltage control mode:
 - i. the **Generation Unit** shall be capable of contributing to voltage control at the **Connection Point** by providing reactive power exchange with the **Transmission System** with a setpoint voltage covering a range [$U_{REG\_MIN} = 0.95$ p.u.; $U_{REG\_MAX} = 1.05$ p.u.] in steps not greater than $\Delta U_{REG} = 0.01$ p.u..
 - ii. The reactive power output shall be zero when the voltage value of the **Transmission System** at the **Connection Point** equals the voltage setpoint.
 - iii. The setpoint may be operated with or without a deadband selectable in a range to be defined by the **Grid Operator**.

iv. Achieving 90 % and 100 % of the change in reactive power output requested by the **Grid Operator** within times $t_{REG\_90\%}$ and $t_{REG\_100\%}$, respectively, to be specified by the **Grid Operator**, with an accuracy of 5 % of the value of the maximum reactive power that can be delivered by the **Generation Units**. The values of $t_{REG\_90\%}$ and $t_{REG\_100\%}$ shall lie within the ranges of [1 – 5 sec] and [5 – 60 sec], respectively.

b) Reactive power control mode:

The **Generation Unit** shall be capable of setting the reactive power setpoint anywhere in the given reactive power range, with setting steps defined by the **Grid Operator** not greater than 5 MVar or 5 % of full reactive power, whichever is smaller, by controlling the reactive power at the **Connection Point** to an accuracy defined by the **Grid Operator** within plus or minus 5 MVar or plus or minus 5 % of the full reactive power, whichever is smaller;

c) Power factor control mode:

The **Generation Units** shall be capable of controlling the power factor at the **Connection Point** within the required reactive power range, specified by the **Grid Operator** according to article CC 5.4.1.1 for **Inverter-based Generation Units**, with a target power factor in steps not greater than ΔU_{REG} , as specified above in article CC 5.4.2.3.a). The **Grid Operator** shall specify the target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output. The tolerance of the target power factor shall be expressed through the tolerance of its corresponding reactive power. This reactive power tolerance shall be expressed by either an absolute value or by a percentage of the maximum reactive power of the **Inverter-based Generation Units**.

CC 5.4.2.4 The **Grid Operator** shall determine the applicable control modes and the channel and procedures for communicating the control reference values.

CC 5.4.3 **Short Circuit Contribution During Faults for Inverter-based Generation**

CC 5.4.3.1 The **Grid Operator** may require **Inverter-based Generation Units** to be capable of providing **Fast Fault Current** at the **Connection Point** in case of both balanced (three-phase) and unbalanced (single-phase or two-phase) faults.

CC 5.4.3.2 The **Grid Operator** shall define the requirements for **Fast Fault Current**. These requirements shall consider:

- a) the criteria and methodology for determining a voltage deviation, as well as the end of the voltage deviation;
- b) the characteristics of the **Fast Fault Current**; and,
- c) the accuracy and timing of injection of the **Fast Fault Current**.

CC 5.5 Management of the Power System

CC 5.5.1 *Synchronization and Re-synchronization*

CC 5.5.1.1 The synchronization of a **Generation Unit** or re-synchronization after a planned shutdown or following the intervention of the protection system, shall be permitted only under the following conditions:

- a) authorization by the **Grid Operator**;
- b) operating frequency and voltage at the **Connection Point** are within the ranges specified in CC 5.1.

CC 5.5.1.2 The conditions for synchronization or re-synchronization of a **Generation Unit** as per article CC 5.5.1.1 shall be agreed upon by the **Grid Operator** and the **Generation Facility Owner**, and shall be included in the **Operational Agreement**.

CC 5.5.1.3 The **Generation Unit** shall be equipped with synchronization devices. The settings related to these synchronization devices shall be agreed upon by the **Grid Operator** and the **Generation Facility Owner** and shall be included in the **Operational Agreement**. The settings shall include voltage, frequency, phase angle range, phase sequence, and deviation of voltage and frequency.

CC 5.5.1.4 Once synchronized to the **Grid**, the **Generation Unit** shall gradually increase its power output up to the target value following the ramping gradient agreed with the **Grid Operator**.

CC 5.5.1.5 Installation of automatic connection system shall be subject to prior authorization by the **Grid Operator**. The **Grid Operator** shall agree upon this capability with the **Generation Facility Owner** during the connection process set out in CC 3, and shall specify the conditions under which a **Generation Unit** is capable of connecting automatically to the network. The conditions shall include:

- a) frequency ranges within which an automatic connection is admissible, and a corresponding delay time; and,
- b) maximum admissible gradient of increase in active power output.

CC 5.5.2 *Ramping Limits*

CC 5.5.2.1 The rates of change of active power output, ramping limits, for a **Generation Unit** shall be controlled in both ramp-up and ramp-down directions and expressed in MW/min. The value of the minimum and maximum ramping limits shall be agreed upon with the **Grid Operator** and shall consider the specific characteristics of the **Generation Unit**, the prime mover technology, and the primary energy source. Typical values for ramping limits shall range from 1 % to 20 % of the **Generation Capacity** per minute.

CC 5.5.2.2 The above ramping limits do not apply in the following two (2) conditions:

- a) where the **Grid Operator** specifically requests a load variation with ramping other than that agreed in article CC 5.5.2.1 above;

- b) during the mandatory or optional provision of **Ancillary Services** that require load variations with ramping outside the range in article CC 5.5.2.1 above.

CC 5.5.3 **Protection Systems**

CC 5.5.3.1 The requirements stated in this CC 5.5.3 shall be complementary to the general requirements on the protection specified under CC 4.5.

CC 5.5.3.2 The protection schemes required for protecting the **Grid** shall be specified by the **Grid Operator**, taking into account the characteristics of each **Generation Unit**. The definition and modification of the protection schemes for both the **Generation Unit** and the **Grid**, as well as the settings relevant to the **Generation Unit** shall be coordinated and agreed upon between the **Grid Operator** and the **Generation Facility Owner**. These provisions shall be indicated in the **Operational Agreement** during the connection process.

CC 5.5.3.3 The protection system of a **Generation Unit** shall have priority over the operational controls due to its critical functions. The protection system ensures the security of the **Grid**, safeguard the health and safety of the working personnel and the public, and limits any potential damage to the **Generation Unit**.

CC 5.5.3.4 With reference to internal electrical faults, the protection schemes and settings shall include the following protections:

- a) external and internal short circuit;
- b) unbalanced load (negative phase sequence);
- c) stator and rotor overload;
- d) over-/under-excitation;
- e) over/under-voltage at the **Connection Point**;
- f) over/under-voltage at the alternator terminals;
- g) inter-area oscillations;
- h) asynchronous operation (pole slip);
- i) protection against inadmissible shaft torsions (for example, subsynchronous resonance);
- j) transformer protection;
- k) differential protection;
- l) restricted earth fault protection;
- m) neutral overcurrent protection;
- n) back-up against protection and circuit breaker malfunction;
- o) over fluxing (U/f);

- p) reverse power;
- q) inadvertent energization;
- r) rotor earth fault
- s) **Generation Unit** stator temperature;
- t) maximum speed;
- u) excitation system fault;
- v) **Generation Unit** rotor vibration;
- w) fault in the cooling system of the **Generation Unit**;
- x) under impedance protection;
- y) rate of change of frequency withstand capability; and,
- z) neutral voltage displacement.

CC 5.5.3.5 With reference to external electrical faults, a **Generation Unit** shall be equipped with a protection system capable of separating it from the **Grid** if the external fault cannot be correctly eliminated by **Grid** protection. The protections shall be limited to opening of the HV or EHV circuit breaker of the **Generation Unit**, in order to separate the **Generation Unit** and step-up transformer from the **Grid**. The protection schemes and settings of the **Generation Unit** shall therefore be coordinated with the **Grid** protection as determined by the **Grid Operator**. The protection schemes and settings may include, but not limited to, the following protections:

- a) maximum current relay;
- b) minimum voltage relay;
- c) maximum voltage relay
- d) distance protection;
- e) protection against unbalanced loads;
- f) maximum and minimum frequency relay;

CC 5.5.3.6 The protection schemes and settings shall be defined in such a way that, in accordance with article CC 5.6.2.4, the **Generation Unit** maintains the operation of its auxiliary services and remains in a state of readiness to resume parallel operation with the **Grid**.

CC 5.5.3.7 References to available international standards relating to protection schemes and settings are given in ANNEX A – REFERENCE STANDARDS):

CC 5.5.4 **Control Systems**

CC 5.5.4.1 The schemes and settings of the control devices of a **Generation Unit** shall be coordinated and agreed upon between the **Grid Operator** and the **Generation Facility Owner**, and shall be provided in the **Operational Agreement** during the connection process.

CC 5.5.4.2 A modification to the schemes and settings of the control devices after the first synchronization shall be agreed upon with the **Grid Operator**.

CC 5.5.5 ***Priority Ranking of Control and Protection Actions***

CC 5.5.5.1 The **Generation Facility Owner** shall organize the protection and the control devices of its **Generation Facility** in accordance with the following priority ranking, listing from highest to lowest:

- a) **Grid** and **Generation Unit** protection;
- b) **Synthetic Inertia**, where applicable;
- c) frequency control;
- d) power limitation; and,
- e) ramping limits.

CC 5.5.6 ***Priority to active or reactive power contribution for Inverter-based Generation Units***

CC 5.5.6.1 The **Grid Operator** shall determine whether active power contribution or reactive power contribution shall have priority during faults conditions requiring **Fault-Ride-Through** capability, taking into account the capabilities of **Inverter-based Generation Units** specified in accordance with this **Connection Code**. Where priority is given to active power contribution, its provision shall be established within a timeframe beginning from the inception of the fault, as specified by the **Grid Operator**, but no later than 150 ms.

CC 5.5.7 ***Power Quality***

CC 5.5.7.1 The **Generation Facility Owner** shall provide, before the initial synchronization, the data related to disturbances of the **Generation Unit**. Based on this data, the **Grid Operator** shall evaluate the effects on the **Grid**, considering the minimum short-circuit power on the **Grid**.

CC 5.5.7.2 The maximum permissible levels of disturbance emissions for a new **Generation Facility** to be connected to the **Grid** or an existing **Generation Facility** undergoing significant modifications, shall be set by the **Grid Operator**.

CC 5.5.7.3 Depending on the connection site and **Grid** conditions, the **Grid Operator** may, at any time following the initial synchronization, require the **Generation Facility Owner** to install additional compensation systems in order to guarantee the achievement of targeted quality standards.

CC 5.5.7.4 The criteria for evaluating the disturbance emission limits shall include the characteristics set out in CC 2.5.

CC 5.5.8 **Simulation Models**

CC 5.5.8.1 Upon the request of the **Grid Operator**, a **Generation Facility Owner** shall provide simulation models for its **Generation Units** with a level of detail adequate to reflect the behavior of each **Generation Unit** in:

- a) steady-state simulation;
- b) electromechanical simulation; and,
- c) electromagnetic transient simulation.

CC 5.5.8.2 The request for the simulation model shall include:

- a) the specification of the format in which models are to be provided by the **Generation Facility Owner**;
- b) the provision of documentation on a model's structure and its block diagrams;
- c) an estimate of the minimum and maximum short-circuit current capacity at the **Connection Point** expressed as a simplified equivalent of the **Transmission System**;
- d) the parameterizations and limitations of the model; and,
- e) the specific sub-models of the components.

CC 5.5.8.3 Upon request by the **Grid Operator**, the **Generation Facility Owner** shall provide measurement recordings of the **Generation Unit**'s performance in order to compare the response of the models with those recordings.

CC 5.6 **Management of Emergency Situations**

CC 5.6.1 **Black Start**

CC 5.6.1.1 A **Generation Unit** with **Black Start Capability** shall comply with the following requirements:

- a) be capable of starting from shutdown without any external electrical energy supply within a maximum period agreed with the **Grid Operator**. Indicative values of time frame can range from one (1) hour for a **Generating Unit** that is operating (hot start) to four (4) hours for a **Generating Unit** that is shutdown (cold start) at the time of the **Blackout State**
- b) with reference to frequency:
 - i. be able to synchronize within the limits defined in CC 5.1.1;
 - ii. be capable of operating in **LFSM-O** and **LFSM-U**, as specified in CC 5.3.4; and,
 - iii. be capable of controlling frequency in case of over-frequency and under-frequency within the whole active power output range between minimum

regulating level and the **Generation Capacity**, as well as at such level to continue to supply the in-house loads.

- c) with reference to voltage:
 - i. be able to synchronize within the limits defined in CC 5.1.2;
 - ii. be capable of automatically regulating dips in voltage caused by connection of **Demand Facilities**; and,
 - iii. control voltage automatically during the restoration phase of the **Grid**.
- d) be capable of operating in parallel with other **Generation Units** within an **Island**.

CC 5.6.2 *Load-rejection and Quick Re-Synchronization*

CC 5.6.2.1 In case of disconnection from the **Grid**, **Generation Units** shall be capable of performing the re-synchronization in accordance with the protection strategy agreed upon by the **Grid Operator** and the **Generation Facility Owner** in the **Operational Agreement**.

CC 5.6.2.2 Where the time for re-synchronization exceeds fifteen (15) minutes, the **Generation Unit** shall be capable of operating in **Load-rejection** and therefore, it shall guarantee stable operating conditions with disconnection of the **Generation Unit** from the **Grid**, and supplying its own auxiliary services from respective station service transformers.

CC 5.6.2.3 The identification of the operation in **Load-rejection** shall not be based exclusively on the switchgear position signals of the **Grid Operator**, but also on actual measures of the power production of the **Generation Unit**.

CC 5.6.2.4 **Generation Units** shall be capable of continuing operation in **Load-rejection**, regardless of any auxiliary connection to the **Grid**. The minimum time of operation in **Load-rejection** for thermal **Generation Units** shall be six (6) hours.

CC 5.6.3 *Remote control for Defence Plan Participation*

CC 5.6.3.1 During the connection process (see CC 3), the **Grid Operator** has the right to request a **Generation Facility Owner** to install remote monitoring and control devices on their **Generation Units** to provide special functions for preserving or restoring secure **Power System** operation, such as remote disconnection and/or remote control of **Generation Units** and/or disconnection of **Load**, and sending and receiving of data.

CC 5.6.3.2 Each **Grid Operator** shall ensure that the functional and technical characteristics of such additional devices are included in its **National Grid Code** or **Defence Plan**.

CC 5.7 *Monitoring and Information Exchange*

CC 5.7.1 **A Generation Facility** shall be capable of exchanging information with the **Grid Operator** in accordance with the following different specifications and purposes.

a) Real-time monitoring:

The **Generation Facility** shall be integrated into the control and operations procedures in real-time of the **Grid** by the **Grid Operator**. Accordingly, the **Grid Operator** can request the **Generation Facility Owner** to install a dedicated **Remote Terminal Unit (RTU)** equipment, during the connection process (CC 3.2.4.1) to perform remote control, remote monitoring, and remote operations actions.

The technical specifications of the **RTU** shall be defined by the **Grid Operator** and indicated in the **Operational Agreement** during the connection process. Among the specifications, the details on the remote measures required to monitor the response of **Generation Units** to frequency variations shall be clearly indicated.

The installation of **RTU** can also be requested of existing **Generation Facilities** in the event of significant changes or partial/total reconstruction of the existing **Generation Facilities** as per CC 1.1.4.b) or as per direct request of the **Grid Operator** towards full compliance with this **Connection Code** in the modalities indicated in CC 1.1.5.

b) Fault recording and monitoring:

To provide recording and monitoring of dynamic system behaviour during faults, **Generation Facilities** shall be equipped with dedicated equipment which meets the following requirements:

- i. the capability to record voltage, current, active power, reactive power, and frequency;
- ii. the technical characteristics agreed upon by the **Generation Facility Owner** and the **Grid Operator**.

c) Information exchange for quick return into service:

Following an outage, the **Generation Facility Owner** shall notify the **Grid Operator** about:

- i. the availability of the **Facility** disconnected during the outage, the causes that led to the disconnection and those that prevented its return into service;
- ii. the time needed to return into service;
- iii. the recordings of the fault or disturbance which caused the outage.

d) Information exchange for fault reconstruction:

For the purpose of fault scenario reconstruction, the **Generation Facility Owner** shall provide the **Grid Operator** with the following:

- i. the recordings detected by disturbance recorders;
- ii. recordings of electromagnetic transients;
- iii. recordings of local signals.

CC 5.7.2 The detailed list of data and information with respective specifications, and the exchange methods for the elements mentioned in article CC 5.7.1, shall be agreed upon by the **Generation Facility Owners** and the **Grid Operator**, and they shall be indicated, for each **Generation Facility**, in the **Operational Agreement**.

CC 5.8 Compliance Monitoring

CC 5.8.1 The **Generation Facility Owner** shall ensure that each **Generation Unit** complies with the provisions of this **Connection Code** throughout its operational lifetime. In the event of a non-compliance, the **Generation Facility Owner** shall notify the **Grid Operator** about the detected non-compliance without delay.

CC 5.8.2 The **Generation Facility Owner** shall notify the **Grid Operator** of:

- a) any planned modification of the technical capabilities of a **Generation Unit** which may affect its compliance with this **Connection Code**, before initiating that modification.
- b) any operational incident or failure of a **Generation Unit** that affect its compliance with this **Connection Code**, without undue delay, after the occurrence of that incident or failure.
- c) the planned test schedules and procedures to be followed for verifying the compliance of the **Generation Unit** with this **Connection Code**, in due time and prior to the launch of the planned test schedules and procedures. The **Grid Operator** shall approve in advance the planned test schedules and procedures. Such approval by the **Grid Operator** shall be provided in a timely manner and shall not be unreasonably withheld.

CC 5.8.3 The **Grid Operator** shall evaluate the compliance of the **Generation Unit** and shall keep the **Generation Facility Owner** informed of the outcome. The compliance assessments shall include:

- a) information and documentations provided by the **Generation Facility Owner** to the **Grid Operator**;
- b) verification and compliance tests executed by the **Grid Operator**;
- c) compliance simulations.

CC 5.8.4 The **Grid Operator** may delegate compliance monitoring activities to third parties.

CC 5.8.5 The **Grid Operator** may consider self-certification tests executed by the **Generation Facility Owner** provided the **Grid Operator** defines the procedure for the self-certification tests.

CC 5.8.6 **Information and Documentation**

CC 5.8.6.1 The **Generation Facility Owner** shall provide the **Grid Operator** with information and documents that describe the characteristics of the **Generation Units** of the **Generation Facility**.

CC 5.8.6.2 The **Generation Facility Owner** shall provide the necessary information and documents to the **Grid Operator**:

- a) at the time of connection request in accordance with CC 3;
- b) following updates to the technical data of the **Generation Units** resulting from modifications in the technical capabilities or operational accidents or faults;
- c) upon request by the **Grid Operator**.

CC 5.8.6.3 The list of information and documentation shall be included amongst documents and information requested during the connection process and they shall be harmonized by the **Grid Operators** within the same **Synchronous Area**. The list of information and documentation shall, at least, include the following:

- a) General information about the **Facility**;
- b) Primary energy source, energy conversion process, the efficiency of each **Generation Unit** and the **Facility**;
- c) the technical constraints related to the conversion process which limit the performance of the **Generation Unit**, and any environmental constraints;
- d) the main characteristics for identifying flexibility in operation;
- e) the characteristics of the **Generation Unit** and **Facility** necessary to characterize the electrical behaviour. These are the characteristics needed to perform static and dynamic calculations such as short-circuit current values, load flow and electromechanical transients;
- f) the characteristics of the control systems and the capability curves. These are needed to characterize the capacity for providing **Ancillary Services**;
- g) data on failure rates;
- h) the capability to provide emergency related operations, such as capability to power isolated **Grid** portions and/or own auxiliary loads, capability to withstand **Load-rejection**, capability to provide restoration services.

CC 5.8.7 **Verification and Compliance Tests Executed by the Grid Operator**

CC 5.8.7.1 The **Grid Operator** shall execute verification and compliance tests to ascertain the validity of the declarations issued by the **Generation Facility Owner** and the compliance with the requirements set in this **Connection Code**.

CC 5.8.7.2 The **Grid Operator** shall communicate the annual plan for the implementation of the verification and compliance tests and the results of the tests to the **Generation Facility Owner**.

The **Grid Operator** may execute tests on the functionality of control systems and relative parameters at any time, using either its personnel or external consultants.

CC 5.8.7.3 The **Generation Facility Owner** shall demonstrate to the **Grid Operator** the reliability and accuracy of the test instruments and equipment.

CC 5.8.7.4 The **Grid Operator** shall define the standard procedures for executing the tests differentiating between **Synchronous Generation Units** and **Inverter-based Generation Units**. At a minimum, the procedures shall include the following:

- a) the level and control functions of the active and reactive power injected into the **Grid**;
- b) the performance of systems for frequency and voltage control in **Emergency State**;
- c) the functions of automatic disconnection of the **Generation Units**;
- d) the requirements pertaining to capabilities and actions required during **Emergency State** operation and **Restoration** actions;
- e) the functionality of the protection devices which need to coordinate with the protection devices installed on the **Grid**.

CC 5.8.7.5 Where a **Generation Unit** fails the compliance test, the **Generation Facility Owner** shall correct the deficiency within an agreed period to attain the relevant registered parameters for that **Generation Unit**. This period shall be agreed upon, based on a return to normalcy plan, between the **Generation Facility Owner** and the **Grid Operator**. The return to normalcy plan shall depend on the nature of the deficiency and the engineering solution that can be implemented. Once a **Generation Facility Owner** corrects the deficiency, it shall immediately notify the **Grid Operator**. The **Grid Operator** shall then require the **Generation Facility Owner** to conduct a new compliance test to verify that the appropriate parameter has been restored to its registered value.

CC 5.8.8 **Compliance Simulations**

CC 5.8.8.1 In addition to the verification of the information and the compliance tests as per CC 5.8.7 above, the **Grid Operator** may assess the compliance of a **Generation Facility** with the requirements set forth in this **Connection Code**, by relying on the simulations of the performance of **Generation Facility** carried out by the **Generation Facility Owner** using the simulation models as referred-to in CC 5.5.8.

CC 5.8.8.2 The **Grid Operator** shall provide the **Generation Facility Owner** with the technical data and **Grid** simulation model, as required for carrying out the required simulations.

CC 5.8.8.3 Generally, the required simulations shall cover the verification of conditions that are difficult to check via compliance testing, such as:

- a) Operation in **LFSM-O** and **LFSM-U**;
- b) Operation in **FSM**;
- c) **Fault-Ride-Through** capability;

- d) **Restoration** of active power after a fault;
- e) **Island** operation;
- f) Reactive power capability;
- g) Correct attenuation of power oscillations.

CC 5.8.8.4 The **Grid Operator** may require the **Generation Facility Owner** to perform supplementary or additional simulations where the information provided in relation to the simulations described in article CC 5.8.8.1 is not sufficient to demonstrate compliance with the technical requirements reported in this **Connection Code**.

CC 6. REQUIREMENTS FOR HIGH-VOLTAGE DIRECT CURRENT SYSTEMS

CC 6.1 General Requirements

CC 6.1.1 The provisions of CC 6 apply to the following **HVDC Systems**:

- a) **HVDC Systems** connecting **Synchronous Areas** or **LFC Areas**, including back-to-back schemes;
- b) **HVDC Systems** embedded within one **LFC Area** and connected to the **Transmission System**; and
- c) **HVDC Systems** embedded within one **LFC Area** and connected to the **Distribution Network** when the **Grid Operator** demonstrates a cross-border impact. The **Grid Operator** shall consider the long-term development of the **Network** in this assessment.

CC 6.1.2 **RES-based Generation Units** connected to the **Grid** through **HVDC Systems** shall be designed with the same requirements valid for **Inverter-based Generation Units** defined in CC 5 of this **Connection Code**, applicable at the **HVDC Interface Point** of the **RES-based Generation Units**.

CC 6.2 Operating Ranges

CC 6.2.1 *Frequency Ranges*

CC 6.2.1.1 All **HVDC Systems** shall be designed, built and operated to be capable of remaining connected to the **Grid** within the frequency ranges, and minimum duration specified in Table CC 12 and according to the following scheme:

- a) one range around the nominal frequency of the **Synchronous Area** or of the connected **Asynchronous Areas** with unlimited duration of operation;

- b) one or more ranges with frequency below the nominal frequency of the **Synchronous Area** or of the connected **Asynchronous Areas** with limited duration of operation as per Table CC 12;
- c) one or more ranges with frequency above the nominal frequency of the **Synchronous Area** or of the connected **Asynchronous Areas** with limited duration of operation as per Table CC 12.

CC 6.2.1.2 In defining the duration referenced in Table CC 12 in the **National Grid Code**, the **Grid Operator** and its **National Regulatory Authority** shall consider the applicable international standards for frequency-related capabilities of **HVDC Converter Units**.

CC 6.2.1.3 The **Grid Operator** and the **HVDC System Owner** may mutually agree on wider frequency ranges, longer minimum duration of operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of an **HVDC System**, if it is needed to preserve or to restore **Grid** security. The **HVDC System Owner** shall not unreasonably withhold consent to such request(s) provided it is economically and technically feasible.

CC 6.2.1.4 **HVDC Systems** shall be capable of automatic disconnection at frequencies specified by the **Grid Operator**. Terms and settings for automatic disconnection shall be agreed between the **Grid Operator** and the **HVDC System Owner**.

Table CC 12. Minimum duration for which an HVDC Converter Station must be capable of operating for frequency deviating from the nominal value of the Synchronous Area without disconnecting from the Grid.

Frequency range	Duration for operation
47.0 Hz – 47.5 Hz	60 sec
47.5 Hz – 48.5 Hz	≥ 30 minutes
48.5 Hz – 49.0 Hz	≥ 30 minutes and not less than the duration for 47.5 Hz – 48.5 Hz range
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 52Hz	30 minutes

CC 6.2.2 **Voltage Ranges**

CC 6.2.2.1 An **HVDC Converter Station** shall be designed, built and operated to be capable of remaining connected to the **Transmission System** within the ranges of the voltage at the **Connection Point** and minimum duration specified in Table CC 13 and in accordance with the following scheme:

- a) one range around the nominal voltage with unlimited duration of operation;
- b) one or more ranges with voltage above the nominal value with limited duration of operation as defined in Table CC 13.

CC 6.2.2.2 The **Grid Operator** and the **HVDC System Owner** may mutually agree on wider voltage ranges, longer minimum duration of operation or specific requirements for combined frequency and voltage deviations (simultaneous overvoltage and underfrequency or simultaneous undervoltage and over-frequency) to ensure the best use of the technical capabilities of an **HVDC System**, if it is needed to preserve or to restore **Grid** security. The **HVDC System Owner** shall not unreasonably withhold consent to such request(s) provided it is economically and technically feasible.

CC 6.2.2.3 **HVDC Converter Stations** shall be capable of automatic disconnection at voltages specified by the **Grid Operator**. Terms and settings for automatic disconnection shall be agreed between the **Grid Operator** and the **HVDC System Owner**.

Table CC 13. Minimum duration for which an HVDC Converter Station must be capable of operating for voltages deviating from the reference 1 pu value (Nominal Voltage for pu calculation is given in the first column) at the Connection Point without disconnecting from the Grid.

Nominal value [kV]	Voltage range [p.u.]	Duration of operation
132, 150, 161, 225	0.85 pu – 1.118 pu	Unlimited
	1.118 pu – 1.15 pu	20 minutes
330, 400	0.85 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	60 minutes

CC 6.3 Immunity to Grid Disturbances

CC 6.3.1 *Fault-Ride-Through Capability*

CC 6.3.1.1 **HVDC Converter Stations** shall be capable of remaining connected to the **Transmission System** and shall continue to operate in a stable manner in the following conditions:

- when the actual course of the phase-to-phase voltages at the **Connection Point** during a symmetrical fault is maintained over a **Fault-Ride-Through** voltage-against-time profile to be specified by the **Grid Operator** according to Figure CC 9; and,
- unless the protection scheme for internal faults requires the disconnection of the **HVDC Converter Station** from the **Transmission System**, the undervoltage protection schemes shall be set by the **HVDC System Owner** to the widest possible technical capability of the **HVDC Converter Station**.

CC 6.3.1.2 The **Grid Operator** shall specify:

- The parameters that define each point of **Fault-Ride-Through** voltage-against-time profile of Figure CC 9, and within the ranges set out in Table CC 14.

- b) voltage level (U_{block}) at the **Connection Points** under specific conditions of the **Transmission System** whereby the **HVDC System** is allowed to block, that is remaining connected to the **Transmission System**, with no active and reactive power contribution for a time frame that shall be as short as technically feasible, and which shall be agreed upon between the **Grid Operators** and the **HVDC System Owner**.

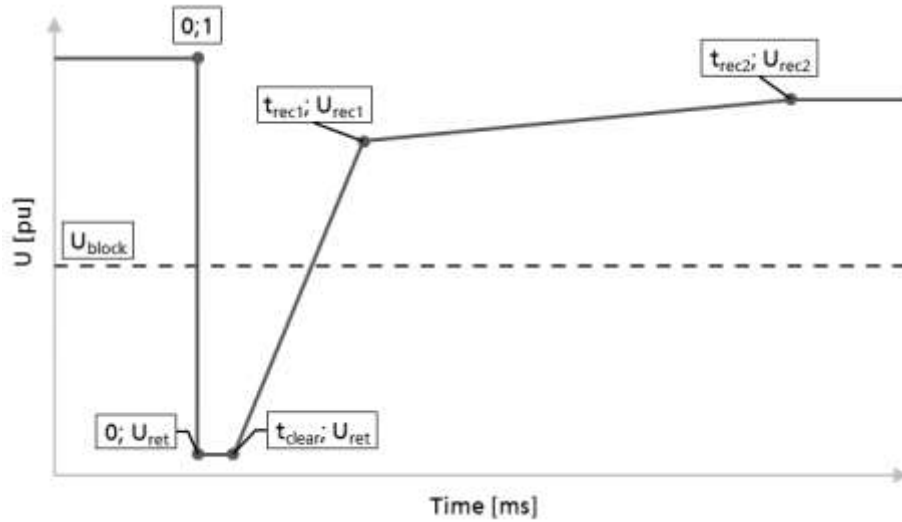


Figure CC 9. Fault-ride-through profile of an HVDC Converter Station.

Table CC 14. Parameters for Figure CC 9 for fault-ride-through capability of HVDC Converter Stations.

Voltage parameters [pu]		Time parameters [sec]	
U_{ret}^{11}	0.00 – 0.3	t_{clear}^{12}	0.14-0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85-0.9	t_{rec2}	from t_{rec1} to 10.0

CC 6.3.1.3 **HVDC Systems** shall comply with the **Fault-Ride-Through** voltage-against-time profile for any pre-fault and post-fault value of short-circuit power between the minimum and maximum values of the short-circuit power expected in the **Connection Point**. In this regard, the **Grid Operator** shall specify and make publicly available such minimum and maximum values of short-circuit power expected in each node of the **Transmission System**.

CC 6.3.1.4 In the area below the **Fault-Ride-Through** voltage-against-time profile, the disconnection of the **Generation Units** due to the intervention of the protection system as referred-to in CC 6.6.4 is acceptable.

CC 6.3.1.5 The installation of ad-hoc undervoltage protection that traces and implements the described **Fault-Ride-Through** voltage-against-time profile is not permitted. In particular, the under-voltage protection shall be set by the **HVDC System Owner** according to the technical limits of the **HVDC Converter Stations**, unless the **Grid Operator** requests other settings.

¹¹ U_{ret} is the retained voltage at the connection point during a fault.

¹² t_{clear} is the instant when the fault has been cleared.

CC 6.3.1.6 In case of asymmetrical faults, the **Fault-Ride-Through** capabilities shall be specified by each **Grid Operator**. A criterion may follow the one-out-of-three logic: the disconnection for asymmetrical faults can be performed when one of the three voltage levels exceeds the same permitted voltage limits displayed in the profile of Figure CC 9 defined for symmetrical faults.

CC 6.3.2 ***Rate of Change of Frequency Withstand Capability***

CC 6.3.2.1 An **HVDC System** shall remain connected to the **Transmission System** and operating if the frequency in the **Network** changes at a rate between – 2.5 and + 2.5 Hz/s, measured at any point in time as an average of the rate of change of frequency for the previous one second (1 s).

CC 6.4 **Stability and Control of the System Frequency**

CC 6.4.1 ***Control of target active power***

CC 6.4.1.1 Following an instruction from a **Grid Operator**, an **HVDC System** shall be capable of adjusting the transmission of active power in each direction of the power flow up to its maximum active power transmission capacity. The detailed technical specifications of control of target active power shall be defined during the connection process in CC 3 of the **HVDC System** and reported in the **Operational Agreement** defined in the connection process as per article CC 3.4.1.a), and they shall at least include the following elements:

- a) minimum values of the active power for each power flow direction through the **HVDC System**, below which the transmission capability active power is not requested;
- b) maximum and minimum power step size for adjusting the transmitted active power;
- c) maximum delay within which the **HVDC System** shall be capable of adjusting the transmitted active power upon receipt of request from the **Grid Operator**.

CC 6.4.1.2 The **Grid Operator** shall also specify:

- a) how a **HVDC System** shall be capable of modifying the transmitted active power injected in case of disturbances into one or more of the **AC Networks** to which it is connected. The delay should not be higher than ten (10) milliseconds.
- b) the capability of the **HVDC System** to perform a fast active power reversal, from its maximum transmission capacity in one direction to its maximum transmission capacity in the opposite direction, in accordance with the applicable rules, conditions, and implementation requirements. The reversal time shall not exceed two (2) seconds.
- c) control functions enabling the **Grid Operators** to modify the transmitted active power for the purpose of cross-border balancing among different **LFC Areas**;

CC 6.4.1.3 An **HVDC System** shall be capable of adjusting the ramping rate of active power variations within its technical capabilities in accordance with instructions from **Grid Operators**. In case of modification of active power according to points a) and b) of article CC 6.4.1.2, there shall be no adjustment of ramping rate.

CC 6.4.1.4 A **Grid Operator**, in coordination with adjacent **Grid Operators**, may specify whether the control functions of an **HVDC System** shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking **FSM**, **LFSM-O**, **LFSM-U** and frequency control. The triggering and blocking criteria shall be specified by the **Grid Operator** and subject to notification to the **National Regulatory Authority**.

CC 6.4.2 **Maximum Loss of Active Power**

CC 6.4.2.1 An **HVDC System** shall be configured in such a way that its loss of active power injection in the same **Synchronous Area** shall be limited to a value specified by the **Grid Operators** for their respective **LFC Area**, based on the **HVDC System's** impact on the **Power System**.

CC 6.4.2.2 Where an **HVDC System** connects two or more **LFC Areas**, the **Grid Operators** shall consult each other in order to set a coordinated value of the maximum loss of active power injection, considering common mode failures.

CC 6.4.3 **Participation in Frequency Control**

CC 6.4.3.1 The **Grid Operator** may require the **HVDC Systems** to be equipped with the facilities to provide **Synthetic Inertia** during fast frequency deviations, by rapidly adjusting the active power injected or withdrawn from the **AC** side of the **Transmission System**.

CC 6.4.3.2 The **Grid Operator** and the **HVDC System Owner** shall agree upon the performance parameters of the control systems installed to provide **Synthetic Inertia**.

CC 6.4.3.3 **HVDC System** shall be capable of operating in the **FSM** which determines a variation in the adjustment of active power with respect to the programmed value of target active power in response to contained variations in the frequency of the **Transmission System**.

CC 6.4.3.4 The **Grid Operator** shall define the parameters that characterize the **FSM** for the **HVDC System** connected to their **Grids** in accordance with Figure CC 10 and within the ranges shown in Table CC 15, and considering that:

- a) P_{MAX} is the maximum active power transmission capacity of the **HVDC System** to which ΔP refers, and it coincides with the maximum continuous active power, which the **HVDC System** can exchange with the **Transmission System(s)** at each **Connection Point**. ΔP is the variation in the active power output from the **HVDC System**. f_n is the nominal frequency in the **AC**-side of the **Transmission System** where the **FSM** is provided and Δf is the frequency deviation in the **AC**-side of the **Transmission System** where the **FSM** is provided.
- b) The **HVDC Converter Station** shall be irresponsive to frequency variations in the range of the **Frequency Response Deadband**, that shall be possible to be set in the range defined by the **Grid Operator(s)** according to the limits reported in Table CC 15.
- c) The variation in power (ΔP) required by the **FSM** is proportional to the frequency deviation (Δf), according to the s_1 and s_2 droop values to be set by the **Grid Operator(s)** according to the limits reported in Table CC 15.

- d) The active power variation required by **FSM** shall be limited by the minimum and maximum active power transmission capacity, that represents the continuous active power which the **HVDC System** can exchange with the **Transmission System** at each **Connection Point** as agreed between the **Grid Operator** and the **HVDC System Owner**.

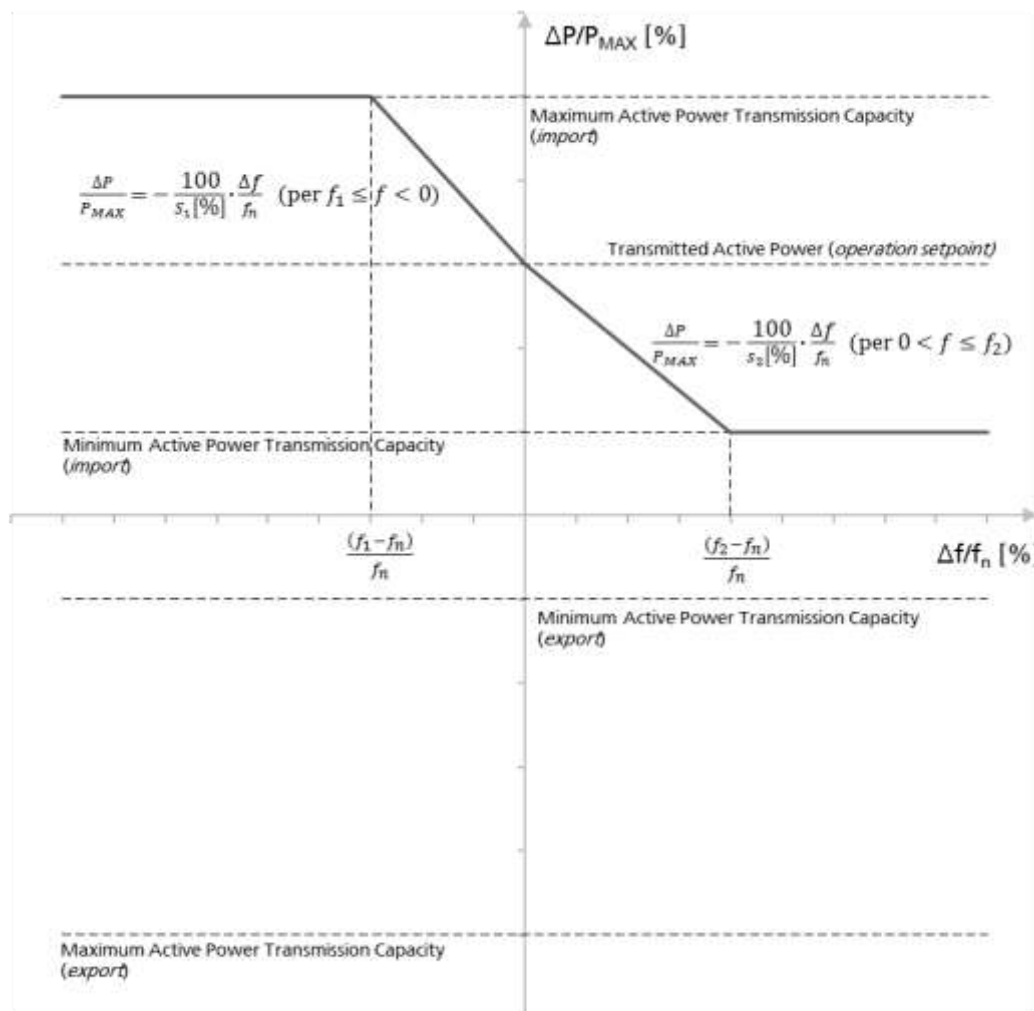


Figure CC 10. Active power frequency response capability of HVDC System in FSM illustrating the case of zero Frequency Response Deadband and insensitivity with a positive active power setpoint.

Table CC 15. Parameters for active power frequency response in FSM (explanation for Figure CC 10).

Parameters	Ranges
Frequency Response Insensitivity of the regulators Δf_i	± 10 mHz
Frequency Response Deadband	$0 - \pm 500$ mHz
Droop s_1	min 0.1%
Droop s_2	min 0.1%

CC 6.4.3.5 In case an **HVDC System** connects two or more **Control Areas** or **Synchronous Areas**, in **FSM** operation the **HVDC System** shall be capable of adjusting the full active power frequency response at any time and for a continuous period.

CC 6.4.3.6 In the event of frequency step changes, the power frequency response of the **Frequency Sensitive Mode (FSM)** shall be activated by the **HVDC System** in such a way it is able to adjust active power output ΔP up to the limit of the active power range requested by the **Grid Operator** (i.e. $\Delta P_1/P_{MAX}$) with a response that is at or above the solid line shown in Figure CC 11, and in accordance with the parameters specified by the **Grid Operator** based on the technology-dependent limitations of the **HVDC System** within the ranges given in Table CC 16.

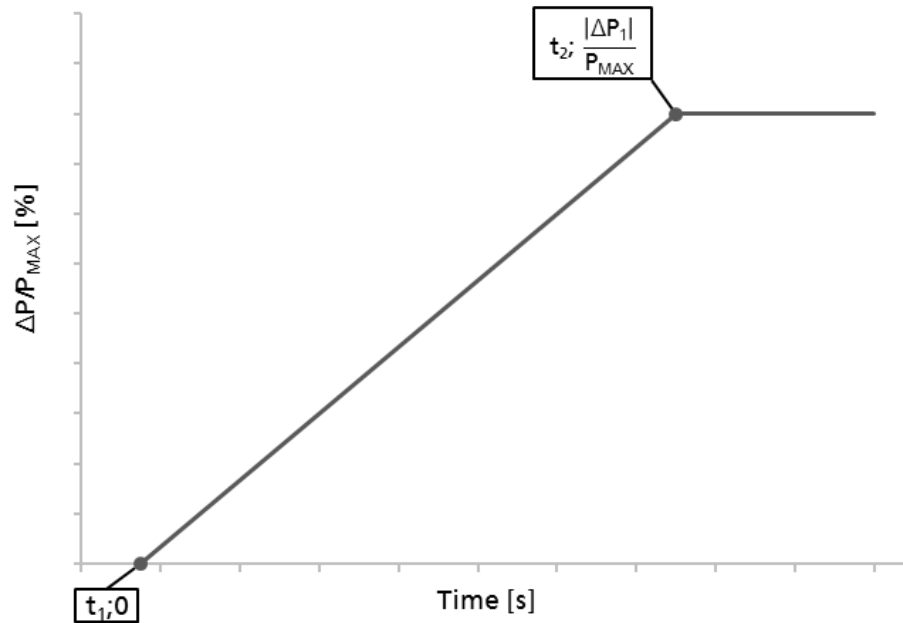


Figure CC 11. Active power frequency response capability.

Table CC 16. Parameters for full activation of active power frequency response resulting from frequency step change (explanation for Figure CC 11).

Parameters	Values
t_1 : Maximum admissible initial delay t_1	0.5 sec
t_2 : Maximum admissible choice of full activation time t_2 , unless longer activation times are allowed by the Grid Operator .	30 sec

CC 6.4.3.7 **HVDC Systems** shall regulate the active power exchanged with the **Transmission System** with respect to the programmed target value, in response to the **AC**-side of the **Transmission System(s)**. This requirement applies during both import and export, with the modes of operation referred to as **LFSM-O** and **LFSM-U**.

CC 6.4.3.8 The **Grid Operator** shall define the actual frequency threshold and droop that characterize the **LFSM-O** and **LFSM-U** or the **HVDC System** connected to their **Grids** in accordance with Figure CC 12 and Figure CC 13 respectively:

- P_{MAX} is the maximum active power transmission capacity of the **HVDC System** to which ΔP refers, and it coincides with the maximum continuous active power, which

the **HVDC System** can exchange with the **Transmission System** at each **Connection Point**. ΔP is the variation in the active power output from the **HVDC System**. f_n is the nominal frequency in the **AC-side** of the **Transmission System** where the **FSM** is provided and Δf is the frequency deviation in the **AC-side** of the **Transmission System** where the **FSM** is provided.

- b) In **LFSM-O**, the values for the frequency threshold f_1^{LFSM-O} shall be set by the **Grid Operator** between 50.2 Hz and 50.5 Hz inclusive, and the droop s_3 adjustable from 0.1% upwards.
- c) In **LFSM-U**, the values for the frequency threshold f_1^{LFSM-U} shall be set by the **Grid Operator** between 49.8 Hz and 49.5 Hz inclusive, and the droop s_3 adjustable from 0.1% upwards.

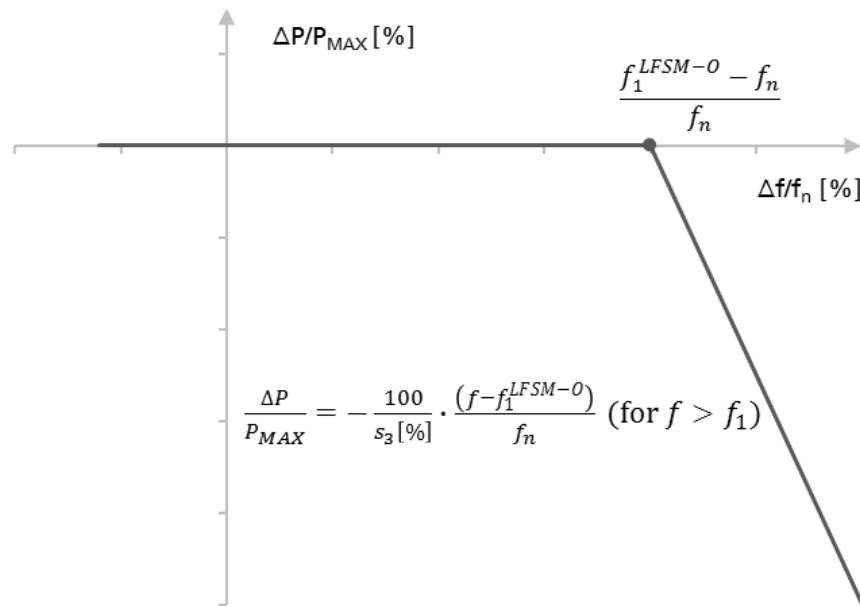


Figure CC 12. Active power frequency response capability of HVDC System in LFSM-O.

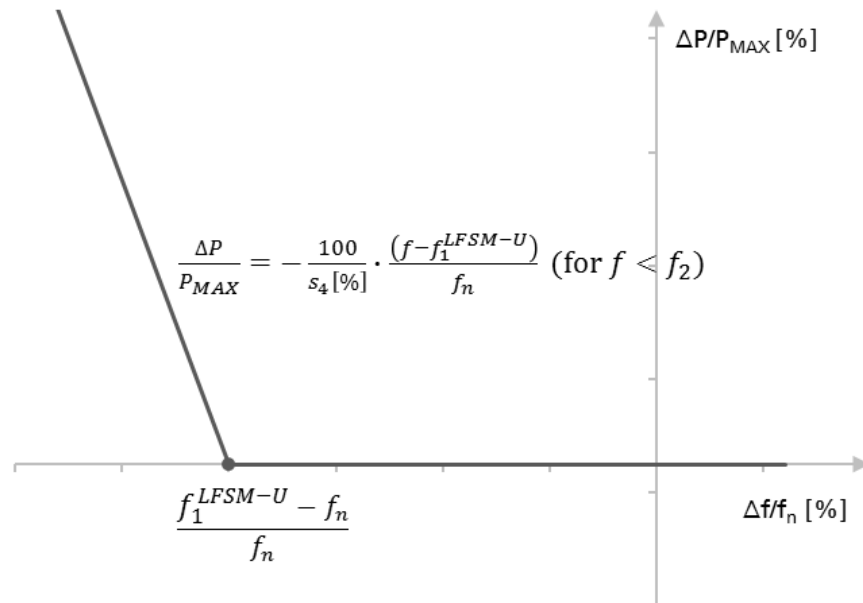


Figure CC 13. Active power frequency response capability of HVDC System in LFSM-U.

CC 6.4.3.9 An **HVDC System** shall be capable of activating the active power frequency response as fast as technically feasible with an initial delay for full activation determined by the **Grid Operator**.

CC 6.4.3.10 With reference to the operation in:

- LFSM-O**, the **HVDC System** shall be capable of adjusting active power down to the minimum active power transmission capacity of the **HVDC System**.
- LFSM-U**, the **HVDC System** shall be capable of adjusting active power up to the maximum active power transmission capacity of the **HVDC System**.
- both **LFSM-O** and **LFSM-U**, the **HVDC System** shall be capable of maintaining stable operation.

CC 6.4.3.11 **HVDC Systems** adopted to connect distant **Loads** to the main **Grid** shall be able to:

- perform a fixed frequency control strategy to maintain the frequency at its nominal value in the **AC Network** containing only **Loads**. This strategy is applied when the frequency control is only performed by the **HVDC Converter Station**. Frequency control shall be achieved by supplying a fixed frequency to the output voltage of the **HVDC Converter Station**. Any change in the **Demand** shall be reflected as an error in the frequency controller, which in turns shall bring the frequency back into its nominal value;
- support passive network that is, to generate **AC** voltages without the need to rely on an **AC** system. This allows for independent rapid control of both active and reactive power and **Black Start Capability**.

CC 6.5 Stability and Control of the System Voltage

CC 6.5.1 Reactive Power Capability

CC 6.5.1.1 The **Grid Operator** shall specify reactive power capability at maximum capacity and reactive power capability below maximum capacity at the **Connection Points**, considering variations in system voltage.

CC 6.5.1.2 Reactive power capability at maximum capacity

CC 6.5.1.2.1 With regard to reactive power capability at maximum capacity, the **Grid Operator** shall define the U - Q/P_{MAX} -profile, which sets the boundaries within which an **HVDC Converter Station** shall be capable of providing reactive power at the maximum active power transmission capacity of the **HVDC System**. The U - Q/P_{MAX} -profile shall be defined according to the following principles and in consistence with Figure CC 14:

- the dimensions of the U - Q/P_{MAX} -profile envelope shall be within the Q/P_{MAX} range and voltage range specified by the **Grid Operator** within the limits defined in Table CC 17.
- the position of the U - Q/P_{MAX} -profile envelope shall be defined by the **Grid Operator** within the limits of a fixed outer envelope defined in Table CC 17.

CC 6.5.1.2.2 The **Grid Operators** within the same **Synchronous Area** shall harmonize the dimensions of the inner envelope of **HVDC Converter Stations** within the limits defined in Table CC 17.

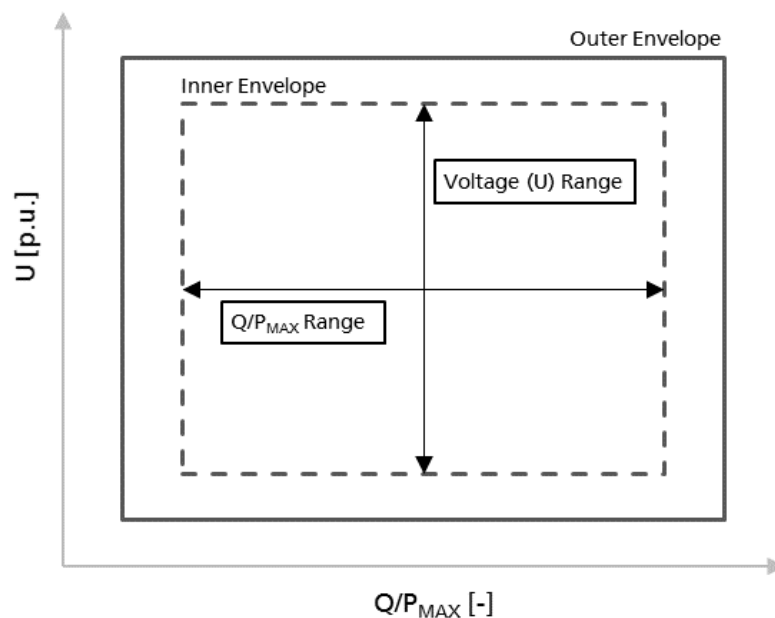


Figure CC 14. U - Q/P_{MAX} -profiles to be defined by the **Grid Operator**.

Table CC 17. Parameters for the inner and outer envelopes in Figure CC 14

Parameters	HVDC Systems
Definition of Inner Envelope	
Q/P_{MAX} Range	0.95 – 1.08

Voltage Range	0.150 – 0.225
Definition of Outer Envelope	
U^{sup}	1.150
U^{inf}	0.850
Q/P_{MAX}^{inf}	- 0.500
Q/P_{MAX}^{sup}	+ 0.650

CC 6.5.1.2.3 An **HVDC System** shall be capable of moving to any operating point on the surface within its U - Q/P_{MAX} profile in appropriate timescales to target values requested by the **Grid Operator**.

CC 6.5.1.3 *Reactive power capability below maximum capacity*

CC 6.5.1.3.1 When operating at an active power output below the maximum active power transmission capacity of the **HVDC System** ($P < P_{MAX}$), the **HVDC Converter Station** shall be capable of operating in every possible operating point, as specified by the **Grid Operator**, and in accordance with the reactive power capability set out by the U - Q/P_{MAX} profile specified in CC 6.5.1.2.

CC 6.5.2 **Voltage Control Modes**

CC 6.5.2.1 **HVDC Systems**, through their **HVDC Converter Stations** shall contribute to the voltage control. The following control modes shall be implemented:

a) Voltage control mode:

- i. the **HVDC Converter Station** shall be capable of contributing to voltage control at the **Connection Point** by providing reactive power exchange with the **Transmission System** to achieve a setpoint voltage covering a range [$U_{REG\_MIN} = 0.95$ p.u.; $U_{REG\_MAX} = 1.05$ p.u.] in steps no greater than $\Delta U_{REG} = 0.01$ p.u.
- ii. The setpoint may be operated with or without a deadband selectable within a range defined by the **Grid Operator**.
- iii. Achieving 90 % and 100 % of the change in reactive power output requested by the **Grid Operator** within time $t_{REG\_90\%}$ and $t_{REG\_100\%}$, respectively, to be specified by the **Grid Operator**, with an accuracy of 5 % of the value of the maximum reactive power that can be delivered by the **HVDC System**. The values of $t_{REG\_90\%}$ and $t_{REG\_100\%}$ shall lie within the ranges of [0.1 – 10 sec] and [1 – 60 sec], respectively.

b) Reactive power control mode:

The **HVDC Converter Stations** shall be capable of setting the reactive power setpoint anywhere in the given reactive power range defined in MVar or in % of maximum reactive power, with setting steps defined by the **Grid Operator**, by controlling the reactive power at the **Connection Point** to an accuracy defined by the **Grid Operator** as a percentage of the full reactive power. The specification of the reactive power range defined by the **Grid Operator** shall consider the capabilities of the **HVDC System**, while complying with CC 6.5.1.

- c) Power factor control mode:

For the purposes of power factor control mode, the **HVDC Converter Station** shall be capable of controlling the power factor to a target at the connection point, while complying with CC 6.5.1. The available setpoints shall be available in steps not greater than a maximum allowed step specified by the **Grid Operator**.

CC 6.5.2.2 The **Grid Operator** shall define the principles and performance governing the switching between control modes as well as conditions and procedures for communicating the voltage reference values.

CC 6.5.3 ***Short Circuit Contribution During Faults***

CC 6.5.3.1 The **Grid Operator** may require **HVDC Systems** to be capable of providing **Fast Fault Current** at the **Connection Point** in case of both balanced (3-phase) and unbalanced (single-phase or two-phase) faults.

CC 6.5.3.2 The **Grid Operator** shall define the requirements for **Fast Fault Current**. These shall consider:

- a) criteria and methodology for determining a voltage deviation;
- b) the characteristics of the **Fast Fault Current**; and,
- c) the accuracy and timing of injection of the **Fast Fault Current**.

CC 6.6 **Management of the Power System**

CC 6.6.1 ***Energization and synchronization of converter stations***

CC 6.6.1.1 The energization or synchronization of an **HVDC Converter Station** to the **AC Transmission System** or the connection of an energized **HVDC Converter Station** to an **HVDC System** shall be performed to limit any voltage transient at the **Connection Point** and its propagation across the **Transmission System**.

CC 6.6.1.2 The **Grid Operator** shall specify the maximum magnitude, duration and measurement window of the voltage transients for the **HVDC Converter Station** within its **Control Area**.

CC 6.6.2 ***Interaction between HVDC systems***

CC 6.6.2.1 Where an **HVDC Converter Station** is located in close electrical proximity with other **HVDC Converter Stations** or other **Facilities**, the **Grid Operator** may require the **HVDC System Owner** to conduct a dedicated study demonstrating that no adverse interactions will occur. The **Grid Operator** shall define the scope and extent of this study. If adverse interactions are identified, the study shall propose appropriate mitigating measures to be implemented to ensure compliance with this **Connection Code**.

CC 6.6.2.2 The **Grid Operator** and the parties identified by the **Grid Operator** as relevant to each **Connection Point**, shall contribute to the study referred to in article CC 6.6.2.1 and shall provide all relevant data and models as reasonably required to meet the purpose of the study. The **Grid Operator** shall collect these inputs from such identified parties.

CC 6.6.2.3 The **Grid Operator** shall assess the result of the study referred to in article CC 6.6.2.1 and may, where necessary, review or reperform the study.

CC 6.6.2.4 Any necessary mitigating actions identified by the study referred to in article CC 6.6.2.1 and reviewed by the **Grid Operator** shall be undertaken by the **HVDC System Owner** as part of the connection of the new **HVDC Converter Station**.

CC 6.6.3 ***Damping Capability for Power Oscillations and Subsynchronous Torsional Interactions***

CC 6.6.3.1 The **HVDC System** shall be capable of contributing to the damping of power oscillations in connected **AC Networks**. The control system of the **HVDC System** shall not reduce the damping of power oscillations. Based on dynamic stability assessment studies undertaken by a relevant **Grid Operator** to identify the stability limits and potential stability problems in its **Transmission System**, the **Grid Operator** shall specify a frequency range of oscillations that the control scheme shall positively damp and the **Network** conditions when this occurs. The selection of the control parameter settings shall be agreed between the **Grid Operator** and the **HVDC System Owner** and defined in the **Operational Agreement** during the connection process referred to in CC 3.

CC 6.6.3.2 Regarding subsynchronous torsional interaction damping control, the **HVDC System** shall be capable of contributing to electrical damping of torsional frequencies. The **HVDC System Owner** shall provide subsynchronous torsional interaction studies to identify the conditions, if any, where subsynchronous torsional interaction exists and propose any necessary mitigation procedure. The **Grid Operator**, and the parties identified by the **Grid Operator** as relevant to each **Connection Point**, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. The **Grid Operator** shall collect these inputs from such identified parties.

CC 6.6.4 ***Protection Systems***

CC 6.6.4.1 The requirements stated in this CC 6.6.4 shall be complementary to the general requirements on the protection specified under CC 4.5.

CC 6.6.4.2 The protection system of an **HVDC System** shall have priority over operational controls due to its critical functions. The protection system ensures the security of the **Power System**, safeguards the health and safety of working personnel and public and limits any potential damage to the **HVDC System**.

CC 6.6.4.3 The protection schemes required for protecting the **Grid** shall be specified by the **Grid Operator**, taking into account the characteristics of each **HVDC System**. The definition and modification of the protection schemes for both the **HVDC System** and the **Grid** as well as the settings relevant to the **HVDC System** shall be coordinated and agreed upon between the **Grid**

Operator and the **HVDC System Owner**. These provisions shall be indicated in the **Operational Agreement** during the connection process in CC 3.

CC 6.6.4.4 The protection system of an **HVDC System** shall be organized according to the following categories:

- a) Protection against internal faults, which shall comply with the following conditions:
 - i. Each component of an **HVDC System** shall be protected against stresses caused by failures not eliminated by the protection system of the **Transmission System** or not covered by it.
 - ii. Each component, subsystem, **HVDC Converter Station** and the entire **HVDC System** shall be protected with coordinated systems that shall be capable of supporting and counteracting any abnormal operating conditions and any fault event. In particular, the protection systems shall maintain their safety measures in the event of any failure to the telecommunications system.
 - iii. The design of the protection system shall take into account the complete redundancy of the protection devices.
- b) Protection of the **Transmission System** which shall comply with the following conditions:
 - i. Each **HVDC System** and its **HVDC Converter Units** shall be equipped with a protection system capable of disconnecting from the **Transmission System** in the event of faults in the **Transmission System** which have not been correctly eliminated.
 - ii. The diagrams and settings of these protection systems shall be coordinated with those of the protection systems of the **Transmission System** and shall be established by the **Grid Operator**.
- c) Additional specific protection systems, which include:
 - i. Protection systems against power oscillations that cannot be controlled by the **HVDC System**.
 - ii. Protection systems that prevent an **HVDC System** to entry into service in the absence of the minimum conditions for the **Transmission System** operation, and that disconnect the **HVDC System** if the last power link connecting the **HVDC System** to the **Transmission System** is opened.

CC 6.6.4.5 Any modification to the protection systems (schemes and / or settings) shall be subject to prior agreement between the **HVDC System Owner** and the **Grid Operator**. The procedures for modifying the protection systems shall be specified in the **Operational Agreement**.

CC 6.6.5 **Control Systems**

CC 6.6.5.1 An **HVDC System** shall be equipped with a control system capable of managing and controlling all the **HVDC Converter Units** of the **HVDC System** in a coordinated manner.

CC 6.6.5.2 During the authorization phase of the connection process in CC 3, the requirements, parameters, and settings of the main control functions of an **HVDC System** shall be agreed upon and formalized between the **HVDC System Owner** and the **Grid Operator**, and shall be provided in the **Operational Agreement**.

CC 6.6.5.3 The parameters and settings of the main control functions of an **HVDC System** shall be implemented within such a control hierarchy that allows their modification, where necessary. The main control functions shall include:

- a) **Synthetic Inertia**, if applicable as referred-to in CC 6.4.3.
- b) **FSM**, **LFSM-O**, and **LFSM-U** as referred-to in CC 6.4.3
- c) reactive power control mode, if applicable as referred-to in CC 6.5.1;
- d) power oscillation damping capability, if applicable as referred-to in CC 6.6.7;

CC 6.6.5.4 For **HVDC Systems** connecting various **Control Areas** or **Synchronous Areas**, the **HVDC System** shall be equipped with control functions enabling the **Grid Operators** to modify the transmitted active power for the purpose of cross-border balancing.

CC 6.6.5.5 The development and design of the control system of an **HVDC Converter Station** shall be based on the principle of redundancy and shall consider the complete duplication of the equipment. Such redundancy shall include:

- a) the measurement circuits, at least from the side of the transducer;
- b) the systems for signal acquisition;
- c) the telecommunication system;
- d) the main processing units and all the equipment necessary for the command, control and protection of the **HVDC Converter Stations**.

CC 6.6.6 ***Priority Ranking of Control and Protection Actions***

CC 6.6.6.1 The **HVDC System Owner** shall organize the protection and the control devices of its **HVDC System** in accordance with the following priority ranking from highest to lowest:

- a) **Transmission System** and **HVDC System** protection;
- b) active power control for emergency assistance;
- c) **Synthetic Inertia**, if applicable;
- d) automatic remedial actions, as specified in CC 6.4.1;
- e) **LFSM-O/U**;
- f) **FSM** and frequency control; and,
- g) power gradient constraint.

CC 6.6.7 ***Power System Stabilizers***

CC 6.6.7.1 The **HVDC System** shall be capable of contributing to the damping of power oscillations occurring in the **AC-side** of the **Transmission System** to which it is connected. The control system of the **HVDC System** shall not reduce the damping of power oscillations. The **Grid Operator** shall specify a frequency range of oscillations that the control scheme shall positively damp and the conditions of the **Transmission System** when this occurs. The selection of the control parameter settings shall be agreed upon between the **Grid Operator** and the **HVDC System Owner** and indicated in the **Operational Agreement**.

CC 6.6.8 ***HVDC System Robustness***

CC 6.6.8.1 The **HVDC System** shall be capable of finding stable operating points with a minimal variation in active power flow and voltage level, during and after any planned or unplanned changes in the **HVDC System** or the **AC Transmission System** to which it is connected.

CC 6.6.8.2 Each **Grid Operator** shall provide detailed information to the **HVDC Facility Owner** during the connection request in accordance with CC 3 based on the data of the **HVDC System** and the **Connection Point**.

CC 6.6.8.3 The following list suggests the minimum conditions in which the stability of the **HVDC System** shall be verified:

- a) opening and closing of the **Elements** of the **Grid** adjacent to the connection;
- b) energizing and tripping of the harmonic filters;
- c) energizing the transformers near the **HVDC Converter Station** or another pole of the same connection;
- d) variation in over and under voltage due to faults;
- e) loss of portions of the **Grid**;
- f) longitudinal failures in the **Grid**.

CC 6.6.9 ***Priority to active or reactive power contribution***

CC 6.6.9.1 Considering the capabilities of the **HVDC System** as defined in this **Connection Code**, the **Grid Operator** shall determine whether priority is given to active power contribution or reactive power contribution during low- or high-voltage conditions and during faults requiring **Fault-Ride-Through** capability. Where priority is assigned to active power contribution, its delivery shall be ensured within a period from the fault inception as specified by the **Grid Operator**.

CC 6.6.10 ***Power Quality***

CC 6.6.10.1 The **HVDC System Owner** shall ensure that the connection of its **HVDC System** to the **Transmission System** does not cause any distortion or fluctuation of the supply voltage on the **Transmission System**, at the **Connection Point**, exceeding the level specified by the **Grid Operator**.

CC 6.6.10.2 For evaluating the impact on the **HVDC System** connection on the **Grid**, the **HVDC System Owner** shall provide, at the time of connection request, all the project data relating to the emission of disturbances. Based on the data provided, the **Grid Operator** evaluates the effects on the **Grid** in conditions of minimum short-circuit power on the **Grid**.

CC 6.6.10.3 The maximum emission levels of distortion or fluctuation of the supply voltage granted to the **HVDC System** are set by the **Grid Operator** in accordance with the expected **Network** performances (see CC 2). They are set by taking into account the planning values adopted by the **Grid Operator**, the short-circuit power at the **Connection Point**, the characteristic data of the **HVDC System**, the emissions of other **Facilities** already connected to the same **Grid**, the emissions transferred from the rest of the **Grid**, and the forecast future emissions of new **Facilities** that have already commenced the connection process under CC 3.

CC 6.6.11 *Simulation models*

CC 6.6.11.1 Upon the request of the **Grid Operator**, an **HVDC System Owner** shall provide simulation models of its **HVDC System** with a level of detail adequate to reflect the behavior of the **HVDC System** in:

- a) steady-state simulation;
- b) electromechanical simulation; and,
- c) electromagnetic transient simulation.

CC 6.6.11.2 The request for the simulation model shall include:

- a) the specification of the format in which models are to be provided by the **HVDC System Owner**;
- b) the provision of documentation on a model's structure and block diagrams;
- c) the specific sub-models of the components, including where applicable:
 - i. **HVDC Converter Stations** models;
 - ii. **AC** component models;
 - iii. models of the **HVDC** line;
 - iv. Voltage and power controller;
 - v. Special control features, if applicable e.g. power oscillation damping function, subsynchronous torsional interaction control;
 - vi. Multi terminal control, if applicable;
 - vii. **HVDC System** protection models as agreed between the **Grid Operator** and the **HVDC System Owner** and indicated in the **Operational Agreement**.

CC 6.6.11.3 The **HVDC System Owner** shall verify the models against the results of compliance tests carried out according to CC 6.9, and a report of this verification shall be submitted to the **Grid Operator**. The models shall then be used for the purpose of verifying compliance with the

requirements of this **Connection Code** including, but not limited to, compliance simulations as provided for in CC 6.9.2 and used in studies for continuous evaluation in **Power System** planning and operation.

CC 6.6.11.4 Upon request of the **Grid Operator**, the **HVDC System Owner** shall provide measurement recordings of the **HVDC System**'s performance in order to compare the response of the models with those recordings.

CC 6.7 Management of Emergency Situations

CC 6.7.1 Black Start

CC 6.7.1.1 Regarding **Black Start Capabilities**, an **HVDC System** shall comply with the following requirements:

- a) Where one **HVDC Converter Station** is energized, an **HVDC System** with **Black Start Capability** shall be capable of energizing the busbar of the **AC** substation connected to its **HVDC Converter Station**, within a timeframe, following system shutdown as specified by the **Grid Operator(s)**
- b) With reference to frequency, the **HVDC System** shall be able to synchronize within the limits defined in CC 6.2.1.
- c) With reference to voltage the **HVDC System** shall be able to synchronize within the limits defined in CC 6.2.2.

CC 6.7.1.2 The **Grid Operator** and the **HVDC System Owner** shall agree on the capacity and availability of the **Black Start Capability** and the operational procedure.

CC 6.8 Monitoring and Information Exchange

CC 6.8.1 **HVDC Systems** shall be capable of exchanging information with the **Grid Operator** according to different specifications and purposes.

CC 6.8.2 Regarding instrumentation for the operation, each **HVDC Converter Unit** of an **HVDC System** shall be equipped with an automatic controller capable of sending/receiving instructions to/from the **Grid Operator**. This automatic controller shall be capable of operating the **HVDC Converter Units** of the **HVDC System** in a coordinated manner. The automatic controller hierarchy for each **HVDC Converter Unit** shall be specified by the **Grid Operator**.

CC 6.8.3 The automatic controller of the **HVDC System** shall be capable of:

- a) Sending the following signal types to the **Grid Operator**:
 - i. Operational signals, providing at least the following:

- start-up signals;
 - **AC** and **DC** voltage measurements;
 - **AC** and **DC** current measurements;
 - active and reactive power measurements on the **AC** side;
 - **DC** power measurements;
 - **HVDC Converter Unit** level of operation in a multi-pole type **HVDC System**;
 - **Elements** and topology status; and,
 - **FSM**, **LFSM-O** and **LFSM-U** active power ranges.
- ii. Alarm signals, providing at least the following:
- emergency blocking;
 - ramp blocking; and,
 - fast active power reversal.
- b) Receiving the following signal types from the **Grid Operator**:
- i. Operational signals, providing at least the following:
- start-up commands;
 - active power set-points;
 - **FSM** settings;
 - reactive power, voltage or similar setpoints;
 - reactive power control modes;
 - power oscillation damping control; and,
 - **Synthetic Inertia**.
- ii. Alarm signals, receiving at least the following:
- emergency blocking command;
 - ramp blocking command;
 - active power flow direction; and,
 - fast active power reversal command.

CC 6.8.4 To provide fault recording and monitoring of dynamic system behaviour, **HVDC Systems** shall be equipped with an appropriate monitoring and recording equipment, which shall comply with the following requirements:

- a) capability of recording **AC** and **DC** voltage, **AC** and **DC** current, active power, reactive power, and frequency;

- b) inclusion of an oscillation trigger, specified by the **Grid Operator**, with the purpose of detecting poorly damped power oscillations.
- c) the settings shall be agreed upon between the **HVDC System Owner** and the **Grid Operator**; and,
- d) inclusion of arrangements enabling the **HVDC System Owner** and the **Grid Operator** to access the information according to communications protocols for recorded data to be agreed between the **HVDC System Owner** and the **Grid Operator** and harmonized between all the **Grid Operators**. Typical standards which communication protocols shall comply with are given in ANNEX A – REFERENCE STANDARDS.

CC 6.9 Compliance Monitoring

CC 6.9.1 Information and documentation

CC 6.9.1.1 The **HVDC System Owners** shall provide the **Grid Operator** with information and documents that describe the characteristics of their **HVDC Systems**. The list of information, documents, and the requirements to be met by the **HVDC System Owners** within the framework of the compliance process shall be made publicly available by the **Grid Operator**. Such list shall be harmonized among the **Grid Operators** and cover at least the following information, documents and requirements:

- a) all the documentation and certificates to be provided by the **HVDC System Owner**;
- b) details of the technical data on the **HVDC System** and **HVDC Converter Station** with relevance to the **Grid** connection;
- c) requirements for models for steady-state and dynamic system studies;
- d) timeline for the provision of system data required to perform the studies;
- e) studies by the **HVDC System Owner** or the owner of **VRES-based Generation Units** connected through **HVDC Systems** to demonstrate the expected steady-state and dynamic performance in accordance with the requirements set out in the **Connection Code**;
- f) conditions and procedures, including the scope, for registering equipment certificates; and,
- g) conditions and procedures for the use of relevant equipment certificates, issued by an authorized certifier, by the **HVDC System Owner**.

CC 6.9.2 Verification and Compliance Test of the Grid Operator

CC 6.9.2.1 Each **HVDC System Owner** shall comply with the testing procedures for the verification of the compliance with the requirements set forth in this **Connection Code** and to be defined by the **Grid Operator**. The tests shall demonstrate the technical capability of **HVDC System to**:

- a) provide leading and lagging reactive power capability according to CC 6.5.1;

- b) operate in voltage control and reactive power modes in accordance with the conditions set forth in CC 6.5.2;
- c) continuously modulate active power over the full operating range between maximum and minimum active power transmission capacities of the **HVDC System** to contribute to frequency control; the same test shall verify the steady-state parameters of frequency regulations;
- d) continuously modulate active power to contribute to frequency control in case of large increase and drop of frequency in the same **Synchronous Area**; the same test shall verify the steady-state parameters of frequency regulations;
- e) adjust the ramping rate of active power variations within its technical capabilities, in accordance with instructions sent out by **Grid Operator**;
- f) energize the busbar of the remote **AC** substation to which it is connected, within a time frame specified by the **Grid Operator**.

CC 6.9.2.2 In addition to the verification of the information and the compliance tests, as per the above paragraphs, the **Grid Operator** can assess the compliance of an **HVDC System** with the requirements set in this **Connection Code** also by relying on the simulations of the performance of **HVDC System** carried out by the **HVDC System Owner** based on the simulation models as referred to in CC 6.6.11.

CC 6.9.2.3 The **Grid Operator** shall provide the **HVDC System Owner** with the technical data and **Grid** simulation model, as required for carrying out the required simulations.

CC 6.10 Additional Requirements

CC 6.10.1 Additional Requirements for Remote-End HVDC Converter Stations

CC 6.10.1.1 Remote-end **HVDC Converter Stations** of an **HVDC System** shall be designed in such a way as to guarantee, at the **HVDC Interface Point**, the frequency and voltage ranges and minimum time periods specified in CC 6.2.

CC 6.10.1.2 The **Grid Operator** and the remote-end **HVDC Converter Station Owner** may agree on wider frequency and/or voltage ranges or longer minimum times for operation to ensure the best use of the technical capabilities of an **HVDC System**.

CC 6.10.1.3 The requirements relating to the **Reactive Power Capability** of the remote-end **HVDC Converter Station** shall be agreed with the **Grid Operators** during the connection process in CC 3 of the **HVDC System**.

CC 7. REQUIREMENTS FOR DEMAND FACILITIES

CC 7.1 Operating Ranges

CC 7.1.1 Frequency Ranges

CC 7.1.1.1 All **Demand Facilities** shall be designed, built and operated to be capable of remaining connected to the **Grid** within the frequency ranges, and minimum duration specified in Table CC 18 and according to the following scheme:

- a) one range around the nominal frequency of the **Synchronous Area** with unlimited duration of operation;
- b) one or more ranges with frequency below the nominal frequency of the **Synchronous Area** with limited duration of operation as per Table CC 18;
- c) one or more ranges with frequency above the nominal frequency of the **Synchronous Area** with limited duration of operation defined in Table CC 18.

CC 7.1.1.2 The **Grid Operator** and the **Demand Facility Owner** may mutually agree on wider frequency ranges and longer minimum duration of operation, if it is needed to preserve or to restore **Grid** security. The **Demand Facility Owner** shall not unreasonably withhold consent to such request(s) provided it is economically and technically feasible.

Table CC 18. Minimum duration for which a Demand Facility must be capable of operating for frequency deviating from the nominal value of the Synchronous Area without disconnecting from the Grid.

Frequency range	Duration for operation
47.5 Hz – 48.5 Hz	≥ 30 minutes
48.5 Hz – 49.0 Hz	≥ 30 minutes and not less than the 47.5 Hz – 48.5 Hz range
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	30 minutes

CC 7.1.2 Voltage Ranges

CC 7.1.2.1 A **Demand Facility** shall be designed, built and operated to be capable of remaining connected to the **Grid** within the ranges of the voltage at the **Connection Point** specified in Table CC 19 and according to the following scheme:

- a) a range around the nominal voltage with unlimited duration of operation;
- b) one or more ranges with voltage above the nominal value with limited duration of operation to be further specified by each **Grid Operator** for its **Power System**.

CC 7.1.2.2 The **Grid Operator** and the **Demand Facility Owner** may mutually agree on wider voltage ranges, longer minimum duration of operation or specific requirements for combined frequency

and voltage deviations (simultaneous overvoltage and underfrequency or simultaneous undervoltage and over-frequency) to ensure the best use of the technical capabilities of a **Demand Facility**, if it is needed to preserve or to restore **Grid** security. The **Demand Facility Owner** shall not unreasonably withhold consent to such request(s) provided it is economically and technically feasible.

- CC 7.1.2.3 For **Demand Facilities** connected to the **Transmission System** with a voltage lower than 132 kV – i.e. 90 kV, 69 kV, 66 kV, 63 kV, 55 kV, 36 kV –, each **Grid Operator** shall agree, with the **Demand Facility Owner**, on voltage ranges at the **Connection Points** at which the **Facility** shall be designed, built and operated to be capable of remaining connected to, if those voltage ranges are relevant for maintaining **Operational Limits**.

Table CC 19. Minimum duration for which a Demand Facility must be capable of operating for voltages deviating from the reference 1 pu value (Nominal Voltage for pu calculation is given in the first column) at the Connection Point without disconnecting from the Grid.

Nominal value [kV]	Voltage range [p.u.]	Duration of operation
132, 150, 161, 225	0.90 pu – 1.118* pu	Unlimited
	1.118 pu – 1.15 pu	[20 - 60] minutes
330, 400	0.90 pu – 1.05 pu	Unlimited
	1.05 pu – 1.10 pu	[20 - 60] minutes

* But not beyond 245 kV as per IEC 60038

CC 7.2 Resilience to Grid Disturbances

CC 7.2.1 Short-circuit requirements

- CC 7.2.1.1 The **Grid Operator** shall specify the maximum short-circuit current at the **Connection Point** that the **Demand Facility** shall be capable of withstanding.
- CC 7.2.1.2 The **Grid Operator** shall inform the affected **Demand Facility Owner** of any change above a threshold for the maximum short-circuit current.
- CC 7.2.1.3 The **Grid Operator** shall request from a **Demand Facility Owner** the data for calculating the contribution of the **Facility** of the short-circuit current. The standard for calculation of short-circuit current is indicated in ANNEX A – REFERENCE STANDARDS.
- CC 7.2.1.4 The **Demand Facility Owner** shall inform the **Grid Operator** of the changes in its **Facility** that will result in changes in short-circuit current contribution above the threshold set by the **Grid Operator**.

CC 7.3 Stability and Control of the System Voltage

CC 7.3.1 Reactive Power Capability

CC 7.3.1.1 A **Demand Facility** shall be capable of maintaining its steady-state operation at their **Connection Point** within a reactive power range specified by the **Grid Operator**.

CC 7.3.1.2 The reactive power range required by the **Grid Operator** shall not exceed 33 % of the greater of the maximum withdrawal capacity and the maximum injection capacity which corresponds to a power factor of 0.95 for withdrawal or injection of active power¹³, measured at the **Connection Point**. An exception may be granted where the **Demand Facility Owner** demonstrates technical or financial system benefits, and such benefits are accepted by the **Grid Operator**

CC 7.4 Management of the Power System

CC 7.4.1 Protection Systems

CC 7.4.1.1 The requirements stated in this CC 7.4.1 shall be complementary to the general requirements on protection described in CC 4.5.

CC 7.4.1.2 The **Grid Operator** shall specify the devices and settings required to protect the **Transmission System** taking into account the characteristics of the **Demand Facility**.

CC 7.4.1.3 The **Grid Operator** and the **Demand Facility Owner** shall mutually agree on the protection schemes and settings relevant for the **Demand Facility** and on any changes to these schemes and settings. These provisions shall be indicated in the **Operational Agreement** during the connection process in CC 3

CC 7.4.1.4 Protection systems of the **Demand Facility** shall have priority over operational controls due to its critical functions. The protection system ensures the security of the **Power System**, safeguards the health and safety of working personnel and public.

CC 7.4.1.5 Protection systems may include the following:

- a) external and internal short circuit;
- b) over- and under-voltage at the **Connection Point** to the **Transmission System**
- c) over- and under-frequency;
- d) overload protection;
- e) **Demand Facility** transformer protection;
- f) back-up against malfunctioning of protection and circuit breaker.

¹³ $power\ factor = \cos\left(\tan^{-1}\left(\frac{Q}{P}\right)\right)$, where $\frac{Q}{P} = 33\%$, $power\ factor = 0.95$

CC 7.4.1.6 References to available international standards relating to protection schemes and settings are given in 0 ANNEX A – REFERENCE STANDARDS:

CC 7.4.2 **Control System**

CC 7.4.2.1 The **Grid Operator** and the **Demand Facility Owner** shall mutually agree on schemes and settings for the different control devices of the **Demand Facility** relevant for system security. The **Grid Operator** and the **Demand Facility Owner** shall agree on any changes to these schemes and settings. The schemes and settings shall be indicated in the **Operational Agreement** during the connection process in CC 3.

CC 7.4.2.2 The agreement on schemes and settings shall cover, at least, the following elements:

- a) **Island** operation;
- b) damping of oscillations;
- c) disturbances to the **Transmission System**;
- d) automatic switching to emergency supply and **Restoration** to normal topology;
- e) automatic circuit-breaker re-closure on single-phase faults.

CC 7.4.3 **Power Quality**

CC 7.4.3.1 The **Demand Facility Owner** shall ensure that the connection of its **Demand Facility** to the **Transmission System** does not disturb **Grid** performance specifications at the **Connection Point**, beyond the disturbance levels defined by the **Grid Operator**.

CC 7.4.3.2 For the purpose of assessing the impact on the **Demand Facility** connection on the **Grid**, the **Demand Facility Owner** shall provide, at the time of connection request, all the project data relating to the emission of disturbances. Based on the data provided, the **Grid Operator** shall evaluate the effects on the **Grid** under conditions of minimum short-circuit power on the **Grid**.

CC 7.4.3.3 The maximum levels of emission of disturbances granted to a **Demand Facility Owner** whose **Facility** is to be connected to the **Grid**, or which intends to make significant modifications to the already existing **Demand Facility**, shall be set by the **Grid Operator** in accordance with the expected **Network** performances (see CC 2). The maximum levels of emission shall be set by taking into account the planning values adopted, the short-circuit power at the **Connection Point** of the **Demand Facility**, the emissions of other **Facilities** already connected to the same **Grid**, emissions transferred from the rest of the **Grid**, and future emissions of new **Facilities** that have already begun the connection process according to CC 3.

CC 7.4.4 **Simulation Models**

CC 7.4.4.1 Upon identification and request by the **Grid Operator**, a **Demand Facility Owner**, whose **Facility**'s operation may potentially disturb the operation of the **Power System**, shall provide

simulation models for its **Demand Facility** with a level of detail adequate to reflect the behavior of the **Facility** in:

- a) steady-state simulation;
- b) electromechanical simulation; and,
- c) electromagnetic transient simulation.

CC 7.4.4.2 The request for the simulation model from the **Grid Operator** shall include:

- a) the specification of the format in which models are to be provided by the **Demand Facility Owner**;
- b) the provision of documentation on a model's structure and its block diagrams;
- c) an estimate of the minimum and maximum short circuit capacity at the **Connection Point** expressed as a simplified equivalent of the **Transmission System**;
- d) the parameterizations and limitations of the model; and,
- e) the specific sub-models of the components.

CC 7.4.4.3 Upon request of the **Grid Operator**, the **Demand Facility Owner** shall provide measurement recordings of the **Facility's** performance in order to compare the response of the models with the measurement recordings.

CC 7.5 Management of Emergency Situations

CC 7.5.1 Demand Disconnection and Reconnection

CC 7.5.1.1 A **Demand Facility** shall be equipped with low frequency **Demand** disconnection capabilities with the specifications and settings defined by the **Grid Operator**, including:

- a) capability to enable automatic low frequency disconnection of the whole or a proportion of the **Demand**;
- b) the possibility to specify a disconnection trigger based on a combination of low frequency and rate-of-change-of-frequency;
- c) the possibility to disconnect **Demand** in stages;
- d) operational settings of **Demand** disconnection: frequency ranges, operating time, voltage lock-out;
- e) activation input.

CC 7.5.1.2 The **Grid Operator** may specify low voltage **Demand** disconnection capabilities. The **Grid Operator** shall define respective specifications and settings.

CC 7.5.1.3 With regard to the capability of reconnection after a disconnection of **Demand Facilities**:

- a) the **Grid Operator** shall specify the conditions under which a **Demand Facility** is entitled to reconnect to the **Transmission System**;
- b) the installation of automatic reconnection systems shall be always subject to prior authorization by the **Grid Operator**;
- c) the **Grid Operator** shall agree with the **Demand Facility Owner** on the settings of synchronization devices prior to connection of the **Demand Facility**, including voltage, frequency, phase angle range and deviation of voltage and frequency. Such agreed settings shall be specified in the **Operational Agreement** during the connection process.

CC 7.5.1.4 A **Demand Facility** shall be capable of being remotely disconnected from the **Transmission System** when required by the **Grid Operator**. The **Grid Operator** shall specify the time required for remote disconnection.

CC 7.6 Monitoring and Information Exchange

CC 7.6.1 **Demand Facilities** shall be capable of exchanging information with the **Grid Operator** in accordance with the different specifications and purposes agreed between the **Grid Operator** and the **Demand Facility Owner** and detailed in the **Operational Agreement**.

CC 7.6.2 The types of information to be provided by the **Demand Facility Owner** to the **Grid Operator** are:

- a) Real-time monitoring:

The **Facility** shall be integrated in the control and operations procedures in real-time of the **Grid** by the **Grid Operator**. Accordingly, for the **Functional Operation** of the **Grid**, at least the following signals and measurements shall be exchanged:

- i. identification of position of the circuit breakers and disconnect switches;
- ii. voltage measurements;
- iii. measurements of active power, reactive power, and line currents.

- b) Fault recording and monitoring:

To provide recording and monitoring of dynamic system behaviour during faults, **Demand Facilities** shall be equipped with dedicated equipment (e.g. involving disturbance recorder, fault locator and chronological event recording) which meets the technical characteristics to be agreed upon by the **Demand Facility Owner** and the **Grid Operator**. In the event of faults, the **Demand Facility Owner** is required to provide the **Grid Operator** with the local fault reports and records of the installed monitoring equipment.

CC 7.6.3 The specific data and information requirements, along with the mode of exchange, shall be agreed between the **Demand Facility Owner** and the **Grid Operator**, and shall be specified for each **Demand Facility** in the **Operational Agreement**.

CC 7.7 Compliance Monitoring

CC 7.7.1 The **Demand Facility Owner** shall ensure that the **Facility** complies with the requirements of this CC 7 for its entire operational lifetime.

CC 7.7.2 The **Demand Facility Owner** shall notify the **Grid Operator** of:

- a) any planned modification of the technical capabilities of its **Demand Facility** which may affect its compliance with the requirements of this **Connection Code**, before initiating that modification.
- b) any operational incident or failure of a **Demand Facility** that affect its compliance with the requirements of this **Connection Code**, without undue delay, after the occurrence of that incident or failure.
- c) the planned test schedules and procedures to be followed for verifying the compliance of its **Demand Facility** with the requirements of this **Connection Code**, in due time and prior to the launch of the planned test schedules and procedures. The **Grid Operator** shall approve in advance the planned test schedules and procedures. Such approval by the **Grid Operator** shall be provided in a timely manner and shall not be unreasonably withheld.

CC 7.7.3 The **Grid Operator** shall evaluate the compliance of the **Demand Facility** and shall keep the **Demand Facility Owner** informed about the outcome of the compliance assessments which shall include:

- a) the information and documentations provided by the **Demand Facility Owner** to the **Grid Operator**;
- b) verification and compliance tests executed by the **Grid Operator**;
- c) compliance simulations.

CC 7.7.4 The **Grid Operator** may delegate compliance monitoring activities to third parties.

CC 7.7.5 Information and Documentation

CC 7.7.5.1 The **Demand Facility Owner** shall provide the **Grid Operator** with information and documentation that describe the characteristics of the **Demand Facility**.

CC 7.7.5.2 The list of information and documentations shall be harmonized among the **Grid Operators** of the same **Synchronous Area** and shall, at a minimum, include the following:

- a) details of the technical data concerning the **Demand Facility** and in relation to its connection or operation;
- b) requirements for models for steady-state and dynamic system studies;
- c) conditions and procedures including scope for registering equipment certificates;

- d) conditions and procedures for the use of relevant equipment certificates issued by an authorized certifier to the **Demand Facility Owner**.

CC 7.7.5.3 The **Demand Facility Owner** shall provide the necessary information and documentation to the **Grid Operator**:

- a) at the time of connection request in accordance with CC 3;
- b) following changes to the technical data of the **Demand Facility** resulting from changes in the technical capabilities, operational accidents, faults or any other events;
- c) upon request by the **Grid Operator**.

CC 7.7.6 ***Verification and Compliance Tests Executed by the Grid Operator***

CC 7.7.6.1 The **Grid Operator** shall execute verification and compliance tests to ascertain the validity of the declarations made by the **Demand Facility Owner** and the compliance with the requirements set in this **Connection Code**.

CC 7.7.6.2 The **Grid Operator** shall communicate the annual plan for the implementation of the verification and compliance tests and the results of the tests to the **Demand Facility Owner**. Considering the importance of the controlling systems and the relative parameters, the **Grid Operator** may conduct tests on their functionality at any time.

CC 7.7.6.3 The **Grid Operator** shall define the standard procedures for executing the tests. At a minimum, the procedures shall include the following:

- a) testing for disconnection and reconnection;
- b) testing for information exchange.

CC 7.7.7 ***Compliance Simulations***

CC 7.7.7.1 The **Grid Operator** may, in addition to the verification of the information and the compliance tests in CC 7.7.6, assess the compliance of a **Demand Facility** with the requirements set forth in this **Connection Code** by relying on the simulations of the performance of the **Demand Facility** carried out by the **Demand Facility Owner** using the simulation models referred to in CC 7.4.4

CC 8. REQUIREMENTS FOR GENERATION UNITS BELOW 132 KV, DISTRIBUTED GENERATION, AND MICROGRIDS

CC 8.1 General Provisions

CC 8.1.1 A **Grid Operator** shall have the capability to design and implement connection requirements for **Distributed Generation** to ensure reliable and secure system operation. However, where the **Distributed Generation** is required to provide **Ancillary Services**, the connection requirements shall be consistent with the operational requirements of the **WAPPITS**.

CC 8.1.2 A **Grid Operator** shall have the capability to design and implement connection requirements for the integration of **Isolated Microgrids** into the **Network**. For grid integration, an **Isolated Microgrid** may either:

- a) disaggregate its internal **Loads** and **Generation Units**, in which case each unit shall comply individually with the applicable requirements for **Distributed Generation**; or
- b) operate as a unitary system, whereby the **Microgrid** is treated as a single entity at the **Connection Point**. In this case, the **Microgrid** shall exploit its aggregating functionalities, coordinating internal **Loads** and **Generation Units** to present a unified operational profile to the **Network** and, where applicable, provide **Ancillary Services** as an integrated system.

CC 8.2 Requirements for Generation Units below 132 kV and Distributed Generation (DG)

CC 8.2.1 The requirements stated in CC 8.2 shall apply to the following **Generation Units**, whether **Synchronous Generation Units** or **Inverter-based Generation Units**:

- a) **Generation Units** to be connected to the **Network** at a voltage level below 132 kV, and
- b) **Generation Units** that have a **Nominal Power** below 10 MW and above 100 kW.

CC 8.2.2 **Generation** from **Generation Units** having the features in article CC 8.2.1 and connected to the **Distribution System** shall be referred to as **Distributed Generation**.

CC 8.2.3 The requirements for the **Generation Units** below 132 kV and the **Distributed Generation** are a subset of the requirements for the **Generation Facilities** connected to the **Transmission Systems** (CC 5). Table CC 20 indicates the requirements specified in CC 5 for **Generation Facilities** connected to the **Transmission Systems** and establishes their applicability to the **Generation Units** below 132 kV and the **Distributed Generation**.

Table CC 20. Application of connection requirements for Generation Units connected to the Transmission System to the Generation Units below 132 kV and the Distributed Generators.

Article	Requirement	Application to Units < 132 kV and Distributed Generation [Yes / No]	Provision
Operating Ranges			
CC 5.1.1	Frequency Ranges	Yes	The Grid Operator shall define the frequency ranges at which the Generation Units below 132 kV and the Distributed Generation shall be designed, built and operated to be capable of remaining connected to the Network. This functionality shall be coordinated with the electric protection interface of the Generation Units below 132 kV and the Distributed Generation.
CC 5.1.2	Voltage Ranges	Yes (optional)	The Grid Operator may define the voltage ranges at which the Generation Units below 132 kV and the Distributed Generation shall be designed, built and operated to be capable of remaining connected to the Network. If implemented, this functionality shall be coordinated with the electric protection interface of the Generation Units below 132 kV and the Distributed Generation.
Resilience to Grid Disturbances			
CC 5.2.1	Fault-Ride-Through Capability	Yes	Generation Units below 132 kV and Distributed Generation shall be robust enough to withstand voltage dips caused by faults to avoid cascading effects that may lead to more severe disturbances. The Grid Operator shall specify the parameters that define each point of Fault-Ride-Through voltage-against-time profile for the Generation Units below 132 kV and the Distributed Generation. The compliance with this provision shall be based on adequate certification tests in lab.
CC 5.2.2	Rate-of-change-of-frequency withstand capability	Yes	Generation Units below 132 kV and Distributed Generation shall be robust enough to withstand certain rate-of-change-of-frequency withstand capability to be defined by each Grid Operator, that could be different from the one required for Generation Units connected to the Transmission System, and continue contributing to stabilizing the Network even in case of frequency disturbances.
Stability and Control of System Frequency			
CC 5.3.2	Control of Target Active Power	Yes	Generation Units below 132 kV and the Distributed Generation shall be able to guarantee proper control of target active power, with related ramp periods, when the setpoint is below the maximum power output as defined by the actual primary energy source. That is, in the case of (i) Active Power Modulation at Abnormal Over-frequency and Underfrequency, and (ii) Active Power Response to Normal Frequency Variations. Moreover, the Generation Units below 132 kV and the Distributed Generation shall be equipped with a logic interface (input port) in order to cease active power output

			within five (5) seconds following an instruction being received at the input port.
CC 5.3.3	Effects Operating Conditions on the Active Power Capability	No	The requirement shall apply to fuel-based Synchronous Generation Units , mainly gas turbine Generation Units , which experience active power reduction in case of underfrequency and temperature variation. Distributed Generation , which is mainly Inverter-based Generation Unit , shall not be impacted.
CC 5.3.4	Active Power Regulation at Abnormal Overfrequency and Underfrequency	Yes (partial)	Each Grid Operator shall define the frequency threshold and droop that characterize only the LFSM-O for Generation Units below 132 kV and Distributed Generation . The LFSM-U shall not be mandatory, since it would require small VRES -based Units to work at limited capacity for long periods of time with the risk of not exploiting those VRES .
CC 5.3.5	Active Power Response to Normal Frequency Variations	Yes	This requirement may require an active contribution from Generation Units below 132 kV and Distributed Generation. Each Grid Operator shall define the frequency threshold and droop that characterize the FSM for Generation Units below 132 kV and Distributed Generation, which shall actively contribute to balance frequency in a context where the amplitude of oscillations is very pronounced. In order not to cause extra design and/or operation costs, this requirement could be limited to Generation Units with nominal power above a given threshold to be set by each Grid Operator.
CC 5.3.6	Frequency Restoration (or Secondary Control)	No	A Distributed Generation is not remotely controlled and cannot hence receive a centralized signal for changing their power setpoint.
CC 5.3.7	Synthetic Inertia for Inverter-based Generation	No	Being an optional requirement for Generation Units connected to the Transmission System , Generation Units below 132 kV and Distributed Generation unit are not required to provide this service.
Stability and Control of the System Voltage			
CC 5.4.1	Reactive Power Capability	Yes	Reactive power capability is essential for ensuring voltage stability. The contribution of Generation Units below 132 kV and the Distributed Generation to the service of supply of reactive power may help Grid Operators maintain the necessary reserve margins. Requirements should be differentiated with respect to Generation Unit technology and Nominal Power.
CC 5.4.2	Voltage Control Modes	Yes	Generation Units below 132 kV and Distributed Generation shall contribute to voltage control by implementing one of the three functions of: • Voltage control mode • Reactive power control mode • Power factor control mode
CC 5.4.3	Short Circuit Contribution During Faults for Inverter-based Generation	Yes (optional)	The Grid Operator shall have the right to specify that Generation Units below 132 kV and Distributed Generation based on Inverter-based Generation Units shall provide a contribution to Fast Fault Current in order to have a proper operation of electric protection architectures.

			Requirements shall be differentiated with respect to Nominal Power of the Units .
Management of the Power System			
CC 5.5.1	Synchronization and Re-synchronization	Yes	Generation Units below 132 kV and Distributed Generation may be synchronized without authorization from the relevant Grid Operator/DSO . Automatic e-synchronization could be allowed given that certain thresholds for frequency and voltage in certain time ranges - to be defined by the relevant Grid Operator/DSO - are respected.
CC 5.5.2	Ramping Limits	Yes	Generation Units below 132 kV and Distributed Generation units shall avoid abrupt changes of their active power output.
CC 5.5.3	Protection Systems	Yes	The Grid Operator shall define the protection requirements for Generation Units below 132 kV and Distributed Generation . Performances, costs and compatibility with equipment already installed in the Network shall be properly evaluated.
CC 5.5.4	Control Systems	Yes	Customized control system requirements shall be defined for Generation Units below 132 kV and Distributed Generation unit by the Grid Operator . Performance, costs and compatibility with equipment already installed in the Network shall be properly evaluated.
CC 5.5.5	Priority Ranking of Control and Protection Actions	Yes	Customized priority ranking of control and protection actions shall be defined for each Generation Unit below 132 kV and Distributed Generation unit by the Grid Operator . Performance, costs and compatibility with equipment already installed in the Network shall be properly evaluated.
CC 5.5.6	Priority to active or reactive power contribution for Inverter-based Generation Units	Yes	Requirements shall be differentiated by the Grid Operator with respect to the Nominal Power of each Generation Unit below 132 kV and Distributed Generation unit.
CC 5.5.7	Power Quality	Yes	Requirements shall be differentiated by the Grid Operator with respect to the Nominal Power of each Generation Unit below 132 kV and Distributed Generation unit.
CC 5.5.8	Simulation Models	No	This requirement may be difficult to be fulfilled by Generation Units below 132 kV and Distributed Generation units and not necessary for their proper operation.
Management of Emergency Situations			
CC 5.6.1	Black Start	No	Bottom-up Restoration plans shall be based on Black Start Capabilities of Generation Units connected Transmission System .
CC 5.6.2	Load-rejection and Quick Re-Synchronization	No	This requirement may be difficult to be fulfilled by a Generation Units below 132 kV and Distributed Generation unit and not necessary for the Grid stabilization.
CC 5.6.3	Remote control for Defence Plan Participation	No	This requirement may be difficult to be fulfilled by Generation Units below 132 kV and single Distributed Generation unit. Therefore, remote control of Generation Units below 132 kV and Distributed Generation is not mandatory (this is particularly true for scattered areas). In fact, it is generally not cost effective to install real-time data monitoring systems in all small-scale Generation Units below 132 kV and Distributed Generation units. Rather, the Grid Operator

			shall have the right to request the relevant DSO to install remote control devices on a representative set of DG systems and then compute and aggregate real-time output.
Monitoring and Information Exchange			
CC 5.7	Monitoring and Information Exchange	Yes (optional / partial)	Regarding real-time monitoring, this shall not be mandatory for Generation Units below 132 kV and Distributed Generation units. As for the above “Remote control for Defence Plan Participation” requirement, it is generally not cost effective to install real-time data monitoring systems in all small-scale Distributed Generation units. Rather, the Grid Operator shall have the right to request the relevant DSO to install remote control devices on a representative set of DG systems and then compute and aggregate real-time output. For Fault recording and monitoring, Information exchange for quick return into service, Information exchange for fault reconstruction requirement, the Grid Operator shall have the right to specify which should be the capabilities of Generation Units below 132 kV and Distributed Generation to exchanging information with the Grid Operator in accordance with the different specifications and purposes.
Compliance Monitoring			
CC 5.8.6	Information and Documentation	Yes	A proper documentation gathering for Generation Units below 132 kV and Distributed Generation is crucial for an effective operation of the Power System .
CC 5.8.7	Verification and Compliance Tests Executed by the Grid Operator	Yes	Equipment certification and validation shall be a mandatory requirement.
CC 5.8.8	Compliance Simulations	No	This requirement may be difficult to be fulfilled by Generation Units below 132 kV and Distributed Generation units and not necessary for their proper operations.

CC 8.3 Requirements for Microgrids

CC 8.3.1 The requirements stated in CC 8.3 shall apply to **Microgrids**, at a voltage level below 132 kV or with **Nominal Power** below 10 MW and above 100 kW, that are permitted to connect to the **Network**.

CC 8.3.2 The requirements shall apply to an existing **Isolated Microgrid** transitioning into a **Connected Microgrid** and a newly installed **Microgrid** to be connected to the **Network**.

CC 8.4 General Characteristics for Microgrid

CC 8.4.1 Control system

CC 8.4.1.1 The control system of a **Microgrid** shall consist of a hierarchical structure with three (3) control layers, that is, primary, secondary, and tertiary. Each control layer shall be defined by its respective time scale and scope of application as follows:

a) **Primary control layer (local control)**

The primary control layer shall mainly perform local data acquisition, information upload and command execution. Since it is based on local measurements and operations, it does not require a communication system. Some of its functions are islanding detection, output control, plug and play **Distributed Generation** unit, devices protection. Different control methods may be applied to the different devices, according to either their grid forming or grid following functionalities. Droop control logics are widely used methods to regulate active power output of **Generation Units**. Primary control acts in a short timeframe of milliseconds to seconds.

b) **Secondary control layer (automatic control)**

The secondary control layer shall be in charge of maintaining frequency and voltage stability within the **Microgrid**. It is a centralized control which compensates stability issues deriving from the primary control layer. It regulates frequency and voltage at the main busbar by sending control signals to primary controllers, regulates power sharing, and may provide additional **Ancillary Services**. It acts in a timeframe of seconds to minutes.

c) **Tertiary control layer (Microgrid Energy Management System)**

The tertiary control layer shall be the highest level of control in **Microgrids**, in charge of functions with the longer time scale in minutes and hours. This controlling system is in charge of the optimal dispatch of **Generation** mix, storage and **Load** consumption schedule, power **Generation** forecasting and **Demand** side management. The optimal operational planning may consider economic as well as environmental criteria and shall be coordinated with the **Grid Operator** in case of **Network**-connected configuration.

CC 8.4.1.2 The following control modes may be implemented to maintain **Microgrid** proper operation:

- a) Master-slave control implies there is one or more **Generation Units** acting as a master and imposing reference voltage and frequency and the other **Generation Units** acting as P-Q controlled sources.
- b) Peer-to-peer control modes imply a shared contribution of all the **Generation Units** to frequency and voltage stabilization through droop control logics.

CC 8.4.1.3 With reference to article CC 8.4.1.2, the master-slave control mode is typical for **Microgrids** in islanded mode of operation, while the peer-to-peer control mode may be used for **Microgrids** in either interconnected or islanded mode of operation.

CC 8.4.2 **Communication system**

CC 8.4.2.1 The **Microgrid** communication system shall have high reliability and real-time performance. Its design shall account for system scale, voltage level, **Microgrid** type, and operation modes, and the communication method shall be selected based on distance, cost, and information requirements to enable fast recovery and automatic control.

CC 8.4.2.2 Communication system shall be composed of the following two distinct networks:

a) **Internal Communication Network**

Internal communication network shall be applied to information exchange among **Distributed Generation** units and internal **Microgrid** devices. Each of the **Microgrid** control layers has different needs depending on the speed and the amount of data that need to be exchanged and processed. Different protocols may hence be used.

b) **External Communication Network**

External communication network shall be applied to bi-directional information exchange between the **Microgrid** and the **Distribution System**. Where implementing this type of communication is not feasible due to its intrinsic complexity, interface criteria with the **Distribution System** shall be properly regulated.

CC 8.4.3 **Protection system**

CC 8.4.3.1 **Microgrids'** protection system shall be designed according to the **Network** architecture, taking into consideration its voltage level, size, grounding mode, and fault current level. It shall consider both connected and islanded mode of operation of the **Microgrid**. Differently from conventional radial **Distribution System**, **Microgrids** experience bi-directional current-flows and the fault current from **Distributed Generation** units may cause the malfunction of the conventional over current protection. The peculiarities and point of attention for designing a proper **Microgrid** protection system shall involve:

a) **Earthing System**

Microgrids shall be provided with a proper earthing system even when working in islanded mode. Their grounding system cannot hence rely exclusively on the **Distribution System's** one, but it may be necessary to switch grounding sources when switching operating modes.

b) **Short-Circuit Protection**

Bi-directional flow of short circuit currents and low current values, especially in islanded mode of operation, may require the usage of advanced protection equipment to detect and manage faults such as directional overcurrent protection.

c) **Directional Power Protection**

This protection is applicable to protect **Generation Units** from running as a motor when excessive power from **Distributed Generation** units is injected into a synchronous machine;

d) **Several Equipment**

A protection system shall be implemented to cover all main components of the **Microgrid**, including the busbar, **Point of Common Coupling (PCC)**, **Generation Units**, and transformers. The protection system may be configured either centrally or in a decentralized manner, depending on the metering and communication systems in place.

CC 8.4.3.2 The protection system of the **Microgrid** shall be coordinated with that of the **Distribution System** in order to guarantee a safe and reliable **Operation**.

CC 8.5 Operating mode

CC 8.5.1 **Connected Microgrids** shall be capable of working in the following two operating conditions:

- a) connected mode, where the **Microgrid** is bi-directionally connected to the **Network** through the **PCC**;
- b) Islanded mode, where the **Microgrid** is disconnected from the **Network** and works as an **Isolated Microgrid**.

CC 8.5.2 *Connected mode*

CC 8.5.2.1 All the requirements listed in CC 8.2 for **Distributed Generation** units shall also apply to a **Connected Microgrid** at **Point of Common Coupling (PCC)**. Due to the specificities of the **Connected Microgrid** such as its capacity to have a stable operation in islanded configuration, some additional considerations and requirements may be indicated. Table CC 21 indicates additional requirements for **Connected Microgrid** at the **Point of Common Coupling (PCC)**.

Table CC 21. Additional requirements for Connected Microgrids.

Code	Requirement	Application to Microgrid [Yes / No]	Provision
Management of Emergency Situations			
CC 5.6.1	Black Start	Yes (optional)	It is an ability that Connected Microgrid may have, due to its ability of working in islanded mode. The Grid Operator has the discretion – case-by-case – to request this capability to Connected Microgrid . During the evaluation of the applicability of this requirement case-by-case, the Grid Operator should consider whether Connected Microgrid is capable to manage reverse power fluxes with the Distribution System in transient operation.
CC 5.6.2	Load Rejection and Quick Re-synchronization	Yes (optional)	It is an ability that Connected Microgrid may have, due to its ability of working in islanded mode.
Monitoring and Information Exchange			
New	Setpoints at PCC	Yes	P,Q setpoints at the PCC may be requested by the Grid Operator .

CC 8.5.3 *Islanded mode*

CC 8.5.3.1 A **Microgrid** may work in islanded mode due to several reasons, in particular:

- a) Unscheduled islanding, where they may be triggered by automatic relays when abnormal conditions at the **PCC** are detected. The **Microgrid** then become autonomous, i.e., isolated from the faulty **Network**.

- b) *Scheduled islanding*, where the modalities required to transition from connected to islanded mode and its duration shall be agreed upon by all the parties involved (i.e. the owner/operator of the **Microgrids** and the **DSO**). The reasons may be optimal dispatching strategies or reliability criteria.

CC 8.5.3.2 While working in islanded mode, a **Microgrid** shall provide some functionalities to ensure safe and reliable operation including:

- a) *Grid forming functionality*, where one or more **Generation Units** with grid forming capabilities and sufficient capacity shall be available to supply reference voltage and frequency.
- b) *Power supply and demand balancing*, where in order to work in islanded mode, a **Microgrid** must have the ability to balance **Generation** and **Demand**. This may also be achieved with **Load Shedding** strategies.
- c) *Voltage Stability*, where the voltage shall be maintained within acceptable ranges in all the nodes of the **Microgrid**. It can be controlled by reactive power generated by **Distributed Generation** units and other devices in the **Microgrid** that shall have sufficient reactive power capacity to compensate for voltage fluctuations.
- d) *Power Quality*, where the requirements may be less stringent than the one specified in CC 5.5.7.
- e) *Synchronization and Reconnection*, where the **Microgrid** is allowed for connected operation when the voltage and frequency of the **Network** are within normal ranges for a certain period of time, after receiving dispatch instructions and authorization. Synchronization control should be adopted for the transition from islanded mode to connected mode. Therefore, as the voltage, frequency and phase angle meet the synchronization conditions, the connected mode could be implemented.
- f) *Black Start Capability*, where the **Microgrid** shall be required to have the capability to autonomously start its grid, re-establish **Generation** and stabilize voltage and frequency after a major disturbance. This is an implicit function in a **Microgrid**.

CC 8.5.3.3 The functionalities listed in article CC 8.5.3.2 shall be general guidelines to be further specified by the **Grid Operator** for its **Power System**.

ANNEX A – REFERENCE STANDARDS

The relevant international standards to be adopted in the Connection Code are listed in Table CC 22. Where international standards are updated, the legally approved latest versions shall take precedence over the references contained in Table CC 22.

Table CC 22. International standards to be adopted in the Connection Code.

Ref. in the Code	Reference international standard
CC 2.5.1a) – THD	IEEE 519, EN 50160, and IEC/TR3 61000-3-6
CC 2.5.1c) – Flicker	IEC/TR3 61000-3-7 and IEC 60868.
CC 2.6.2 and CC 7.2.1.3 – Maximum and minimum Short-Circuit Current calculation	IEC 60909-0
CC 5.5.3.4a) and CC 7.4.1.5a) – External and internal short-circuit	IEC 60255-151
CC 5.5.3.4b) – Asymmetric load (negative phase sequence)	IEC 60255-160 (planned)
CC 5.5.3.4c) – Stator and rotor overload protection	IEC 60255-149
CC 5.5.3.4d) – Over-/under-excitation protection	IEC 60255-140 (planned)
CC 5.5.3.4e) and CC 7.4.1.5b) – Over-/undervoltage at the Connection Point protection	IEC 60255-127
CC 5.5.3.4f) – Over-/undervoltage at the alternator terminals protection	IEC 60255-127
CC 5.5.3.4g) – Inter-area oscillations protection	IEC 60255-178 (planned)
CC 5.5.3.4h) – Asynchronous operation (pole slip) protection	IEC 60255-178
CC 5.5.3.4j) and CC 7.4.1.5e) – Unit transformer protection	IEC 60255-187
CC 5.5.3.4n) and CC 7.4.1.5f) – Back-up against protection and switchgear malfunction	IEC 60255-151, -127
CC 5.5.3.4o) – Over fluxing (U/f) protection	IEC 60255-124 (planned)
CC 5.5.3.4p) – Reverse power protection	IEC 60255-132, -167
CC 5.5.3.4 – Generation Unit load unbalance	IEC 60255-160 (planned)
CC 5.5.3.4s) – Generation Unit stator temperature	IEC 60255-149
CC 5.5.3.4u) – Exciter Fault	IEC 60255-140 (planned)
CC 5.5.3.4w) – Fault of the Generation Unit cooling temperature	IEC 60255-149

CC 5.5.3.4z) – Neutral voltage displacement protection	IEC 60255-150
CC 2.5.1a)– Emissions of harmonic currents	IEEE 519
CC 2.5.1d) – Rapid Voltage Change	IEC/TR 61000-3-7
CC 6.8.4d) – Communication protocols	IEC 60870-5 or equivalent (e.g. European CENELEC standards)
CC 7.4.1.5c) – Over- and under-frequency	IEC 60255-181

ANNEX B – FURTHER SPECIFICATIONS ON LFSM-O/LFMS-U CALCULATION

In principle, **LFSM-O** service may be provided by every **Generation Unit** in operation above its minimum regulating level.

In contrast, the provision of **LFSM-U** service may be subject to further preconditions. An active power increase is possible only for **Generation Units** running below their maximum capacity. Typically, **RES Generation** is dispatched according to its maximum available primary energy, unless there are **Network** constraints. **LFSM-U** capability shall not be understood as requiring **RES Generation** to run at a reduced active power output just to be prepared for an increase in case of an unlikely low frequency event. The economic **Generation** dispatch hence shall not be limited by **LFSM-U** performance.

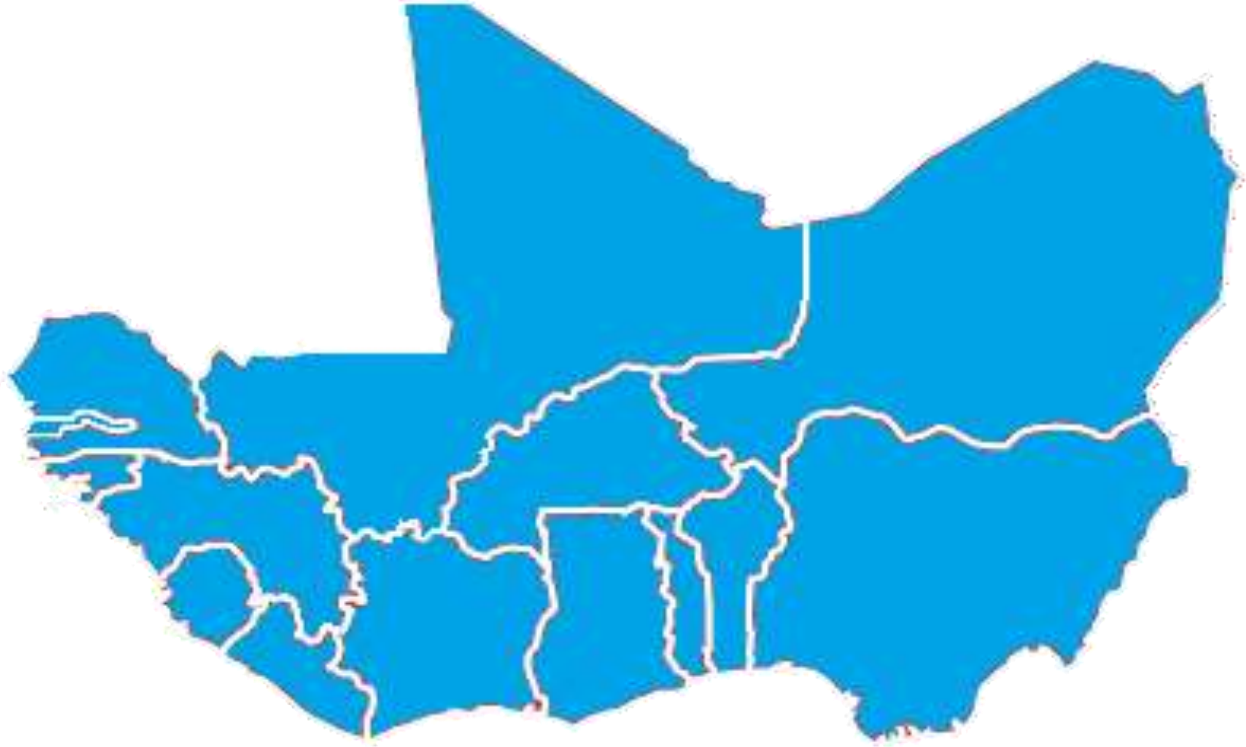
Some numerical examples on **LFSM-U** and **LFSM-O** are indicated in Table CC 23.

Table CC 23. Examples for LFSM-O and LFMS-U calculations for Generation Units.

LFSM-O		LFSM-U	
$\Delta P/P_{ref} [\%]$ $\Delta f/f_n [\%]$ $s_2 [\%] = 100 \cdot \frac{(f - f_1^{LFSM-O})}{f_n} \cdot \frac{P_{ref}}{(-\Delta P)}$ $f_n = 50 \text{ Hz}$ $f_1^{LFSM-O} = 50.5 \text{ Hz} \rightarrow \Delta f_1 = 0.5 \text{ Hz}$ $P_{ref} = P_{MAX} = 50 \text{ MW}$ $s_2 = 5\%$ The Grid frequency increases of $\Delta f > 0$		$\Delta P/P_{ref} [\%]$ $\Delta f/f_n [\%]$ $s_2 [\%] = 100 \cdot \frac{(f - f_1^{LFSM-U})}{f_n} \cdot \frac{P_{ref}}{(-\Delta P)}$ $f_n = 50 \text{ Hz}$ $f_1^{LFSM-U} = 49.5 \text{ Hz} \rightarrow \Delta f_1 = 0.5 \text{ Hz}$ $P_{ref} = P_{MAX} = 50 \text{ MW}$ $s_2 = 5\%$ The Grid frequency decreases of $\Delta f < 0$	
if $\Delta f < \Delta f_1$	LFSM-O not activated, and the Generation Unit shall follow the FSM requirements.	if $ \Delta f < \Delta f_1$	LFSM-U not activated, and the Generation Unit shall follow the FSM requirements.
if $\Delta f \geq \Delta f_1$	e.g. $\Delta f = 0.7 \text{ Hz}$ (i.e. $f = 50.7 \text{ Hz}$) LFSM-O is activated. $s_2 = 100 \cdot \frac{(f - f_1^{LFSM-O})}{f_n} \cdot \frac{P_{ref}}{(-\Delta P)}$ $\Delta P = -P_{ref} \cdot \frac{100}{s_2} \cdot \frac{(f - f_1^{LFSM-O})}{f_n}$ The Generation Unit will react to the positive change of Grid frequency with a decrease in active power equal to: $\Delta P = -50 \text{ MW} \cdot \frac{100}{5\%} \cdot \frac{50.7 \text{ Hz} - 50.5 \text{ Hz}}{50 \text{ Hz}}$		if $\Delta f \geq \Delta f_1$ e.g. $\Delta f = -0.9 \text{ Hz}$ (i.e. $f = 49.1 \text{ Hz}$) LFSM-U is activated. $s_2 = 100 \cdot \frac{(f - f_1^{LFSM-U})}{f_n} \cdot \frac{P_{ref}}{(-\Delta P)}$ $\Delta P = -P_{ref} \cdot \frac{100}{s_2} \cdot \frac{(f - f_1^{LFSM-U})}{f_n}$ The Generation Unit will react to the negative change of Grid frequency with an increase in active power equal to: $\Delta P = -50 \text{ MW} \cdot \frac{100}{5\%} \cdot \frac{49.1 \text{ Hz} - 49.5 \text{ Hz}}{50 \text{ Hz}}$

	$\Delta P = -4 \text{ MW}$ The new set-point of the Generation Unit will be the initial active power output before the abnormal frequency deviation minus 4 MW		$\Delta P = 8 \text{ MW}$ The new set-point of the Generation Unit will be the initial active power output before the abnormal frequency deviation plus 8 MW

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



MC – MARKET CODE

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TITLE I – GENERAL CONDITIONS

MC 1. PRELIMINARY PROVISIONS

MC 1.1 Objectives of the Market Code

MC 1.1.1 This **Market Code**, which is an integral part of the **REM Codes**, provides a set of common principles, methods and technical rules regulating the management of the **WAPP Interconnected Transmission System (WAPPITS)** for the administration, planning and operation of the **Regional Electricity Market (REM)**.

MC 1.1.2 This **Market Code** governs the commercial transactions pertaining to cross border flows of electricity that utilize the transmission lines and associated assets of the **WAPP Interconnected Transmission System (WAPPITS)**.

MC 1.1.3 The objectives of the **Market Code** are to establish and govern an efficient, competitive, transparent, and reliable electricity market for the cross-border sale and purchase of wholesale electricity in the **Region**.

MC 1.2 Principles of the Market Code

MC 1.2.1 The provisions of this **Market Code** are established based on the following:

MC 1.2.1.1 The principle of Competition which guarantees the freedom to undertake and develop activities in the REM based on free and fair competition by implementing objective, transparent and non-discriminatory rules.

MC 1.2.1.2 The principle of **graduality**, which establishes progressive evolution of the REM through the incorporation of new participants, introduction of new market products, the progressive increase of coordinated operation, the development of interconnection networks and the strengthening of **Governing Institutions**.

MC 1.2.1.3 The principle of **third-party access**, which shall ensure the implementation of a system of third-party access to the **Regional** transmission network based on objective, transparent and non-discriminatory technical and commercial access rules, applicable to all eligible participants.

MC 1.2.1.4 The principle of **freedom of transit** which guarantees, within the framework of cross-border electricity exchange between non-neighbouring **Member States**, the transmission of electricity through one or more other **Member States** based on non-discriminatory access to the **WAPP Interconnected Transmission System (WAPPITS)**.

MC 1.3 Definitions and Interpretations

MC 1.3.1 The definitions, acronyms and abbreviations used in this **Market Code** are in the **Glossary and Definitions**, which is an integral part of the **REM Codes**.

MC 1.3.2 For the application of this **Market Code**, unless the context otherwise requires:

- a) A reference to a particular Code, Title, Chapter, Article, Annex or Appendix means a part of the Code, Title, Chapter, Article, Annex or Appendix to the **REM Codes**;
- b) A reference to the masculine includes the feminine, and references to the singular include the plural and vice versa;
- c) A reference to law, regulation or decision shall be construed, at any particular time, as including a reference to any modification, extension, re-enactment or replacement thereof then in force;
- d) A derivative of any term or expression defined or interpreted in the **Market Code** shall be construed according to the relevant definition or interpretation. A reference to another agreement or deed or another instrument shall be construed as a reference to that other agreement, deed or another instrument, as the same may have been, or may from time to time be, modified.

MC 1.4 Annexes and Operational Procedures of the Market Code

MC 1.4.1 The **System and Market Operator (SMO)** shall from time-to-time draft, adopt and implement, and when necessary, amend detailed Annexes and **Operational Procedures**, as it may consider desirable for:

- a) implementation and application of the **Market Code**;
- b) administration of the market; and
- c) clarification of interpretations and the methodologies to be adopted in applying the **Market Code**.

MC 1.4.2 The Annexes and **Operational Procedures** of the **Market Code** shall be approved by **ERERA**.

MC 1.5 Force Majeure Event

MC 1.5.1 Definitions

MC 1.5.1.1 A **Force Majeure Event** is an event that is unforeseeable, beyond the control of and external to the concerned **Party** that prevents it from performing its obligations under the **Market Code**.

MC 1.5.2 *Effects of a Force Majeure Event*

MC 1.5.2.1 For the Market Participant, in the event of a Force Majeure Event:

- a) the obligations of the concerned **Party** under the **Market Code** shall be suspended, and no financial penalty shall be attached to such concerned **Party** for failure to discharge its obligations.
- b) **ERERA** and the **SMO** shall be informed by the concerned **Party** affected by the **Force Majeure Event** of the impossibility to meet its obligations within fifteen (15) minutes of becoming aware of the event. Such notification shall be communicated to the **SMO** as soon as possible via fax and/or e-mail and later confirmed in writing. For operational purposes, the **SMO** shall subsequently inform all **Market Participants** of such an event.
- c) The **SMO** shall verify if the **Force Majeure Event** affects a limited area within the **WAPP Interconnected Transmission System** and inform all unaffected **Market Participants** that trade may continue.
- d) The national **System Operators** of the **Member States** within whose boundaries the **Force Majeure Event** occurs shall use all reasonable endeavours to mitigate the consequences of the event on the **Regional** transmission system according to **Good Utility Practices**.

MC 1.5.2.2 For the **SMO**, in the event of a **Force Majeure Event**:

- a) the trading in the **REM** may be suspended, and no financial penalty shall be imposed on the **SMO** or to any party for failure to discharge obligations because of the **Force Majeure Event**.
- b) the **SMO** shall inform **ERERA** of the impossibility to meet its obligations within fifteen (15) minutes of becoming aware of the event. Such notification shall be communicated to **ERERA** as soon as possible via fax and/or e-mail and later confirmed in writing. For operational purposes, the **SMO** shall subsequently inform all **Market Participants** of such an event.
- c) the **SMO** shall use all reasonable endeavours to mitigate the consequences of the event on the **REM** and shall advise **ERERA** when the **Force Majeure Event** no longer applies and when normal market operations may resume.

MC 1.5.3 *Declaration of Force Majeure Event*

MC 1.5.3.1 Upon notification by the concerned **Party**, **ERERA** shall declare, as soon as possible, an event as a **Force Majeure Event** or not.

MC 1.5.3.2 Following the declaration of an event as a **Force Majeure Event**, **ERERA** shall decide, after consultation, where necessary, with the **SMO**, to suspend, terminate, or cancel the effects of the **Force Majeure Event**.

MC 1.6 Information, Data Management and Databases

MC 1.6.1 Retention of Records and Documents

MC 1.6.1.1 The **SMO**, the **System Operators**, the **Transmission Operators** and **Market Participants**, shall retain, for a minimum period of five (5) years, any record or document they have prepared based on the provisions of the **Market Code**. For the purpose of this provision, the term ‘record’ or ‘document’ means **Information**, whether it has been generated or made, like paper, on film, by electronic means or any other means.

MC 1.6.2 Provision and Handling of Information

MC 1.6.2.1 The **SMO** and other **Market Actors** shall provide the **Information** required for the functioning of the **REM** in accordance with the timelines specified and, in the form and manner required by the **REM Codes**, or any other rule Published by **ERERA** and the **SMO**.

MC 1.6.2.2 **Information** provided by any **Entity** in compliance with the **REM Codes** shall be factual, correct and complete to the best knowledge of the **Entity** providing it, at the time it is provided. No **Entity** shall knowingly or recklessly provide such **Information**, which at the time and under the circumstances in which it is provided, is misleading or deceptive, or does not include a fact or element necessary to ensure that such **Information** is not misleading or deceptive.

MC 1.6.2.3 Where an **Entity** discovers that any **Information** it previously provided to any other **Entity** in compliance with the **REM Codes** is false, incorrect, incomplete, misleading, or deceptive, it shall promptly rectify and provide the factual, correct, complete, not misleading or deceptive **Information** to the **Entity** to whom the said **Information** was originally delivered.

MC 1.6.2.4 Subject to the confidentiality provisions of the **REM Codes**, the **Regional Institutions** are authorized to use any data, records, or **Information** obtained in exercising the powers, functions, and duties set out in the **REMR**. The **Regional Institutions** may use such **Information** in connection with the **REM** to carry out the procedures provided for in the **REM Codes**, including but not limited to:

- a) A process for making modifications to the **REM Codes** or to any other **REMR**;
- b) A process for the application of sanctions in accordance with the provisions of the **REM Codes** or any other **REMR**;
- c) A **Dispute** resolution process according to the provisions of the **REM Codes** or any other **REMR**;
- d) Technical audits as set out in the **REM Codes**.

MC 1.6.3 Confidentiality in Data Management

MC 1.6.3.1 The confidentiality issues are ruled in MC 25.2 and shall be followed by **Regional Institutions** and **Market Actors**. The classification of the confidentiality in **Information** is detailed in article MC 25.2.2 and the disclosure regulations in article MC 25.2.3.

MC 1.6.4 ***Conditions for Information Access***

MC 1.6.4.1 Any **Entity** or person who, by any means, consults, retrieves or stores **Information** Published or made available by **ERERA** or the **SMO**, shall do so at its own expense and responsibility. Where a **Market Participant**, any other **Entity** or a person requests **Information** in the possession or under the control of **ERERA** or the **SMO**, such **Information** may be provided, unless otherwise restricted by the **REM Codes**.

MC 1.6.4.2 Without prejudice to any specific obligation of the **SMO** to provide **Information** under the **REM Codes**, the **SMO** may upon request provide the non-confidential **Information** related to the operation of the **REM** to **Market Actors** or any other **Entity** or person. The **SMO** shall determine the timeframe for the delivery of the **Information**, and may invoice the requesting party directly to recover the cost of providing the **Information**, in accordance with the procedure approved by **ERERA**.

MC 1.6.4.3 Where the **Information** is available in electronic mode, it may be supplied in read-only format, unless otherwise specified in the **REM Codes**.

MC 1.6.4.4 **ERERA** and the **SMO** shall implement access control and security protocols for confidential **Information** to which they allow access through electronic means of communication.

MC 2. REGIONAL ELECTRICITY MARKET STRUCTURE

MC 2.1 Basic Principles for the Organization and Functioning of the REM

MC 2.1.1 The **Regional Electricity Market (REM)** is a wholesale market at the **Regional** level whose organization and operation are based on the following:

- a) Electricity trading takes place in the market by opportunity exchanges through contracts between **Market Participants** and from opportunity exchanges resulting from anonymous centralized day-ahead transactions;
- b) **Market Participants** may buy and sell electricity freely without discrimination of any kind, and the transmission and free transit of electricity through the networks in the **WAPPITS** are guaranteed;
- c) **Market Participants** may install **Generation** plants in any **Member States** in order to participate in the **Regional Electricity Market** subject to compliance with **National** and **Regional** laws and regulations;
- d) **Market Participants** have free access to the Regional and national transmission **Grids** subject to compliance with **National** and **Regional** laws and regulations.
- e) The **REM** has its own rules and operates in complete autonomy from the national electricity markets of the **Member States** whose transactions are also carried out through their national **Grids** as well as the infrastructure of the **WAPPITS**.

MC 2.1.2 The purpose of the **Regional Electricity Market** is to enhance **Security of Supply** and to enable new exchange and trading across the region. Additionally, it gives the rights to buy and sell electricity to the **Entities** engaged in the activities of **Generation**, supply, distribution, and trading of electricity, as well as eligible consumers. The **Entities** engaged in buying and selling electricity are called **Market Participants**.

MC 2.2 Actors of the Regional Electricity Market

MC 2.2.1 **Market Actors** are **Entities** engaged in the activities of **Generation**, supply, transmission, distribution, and trading of electricity, including eligible consumers, the **National Regulatory Authorities** and other national institutions and **Regional Institutions** involved in the functioning of the **REM**.

MC 2.2.2 An **Entity** seeking to engage in buying and selling electricity in the **Regional Electricity Market** shall be authorized and admitted to participate in the **Regional Electricity Market**. This **Market Code** sets out the conditions for access and admission to the **Regional Electricity Market**.

MC 2.2.3 **Entities** engaged in the transmission and system operations cannot buy and sell electricity but have the duty and the rights to provide **Regional** transmission services and system operation

services. Those **Entities** engaged in providing both transmission and system operation services are called **Grid Operators**.

MC 2.2.4 Pursuant to the provisions of this **Market Code**, **Grid Operators** shall have their services remunerated by the **Market Participants**.

MC 2.3 Characteristics of the Regional Electricity Market

MC 2.3.1 *Type of Markets in the REM*

MC 2.3.1.1 The Regional Electricity Market operated by the **SMO** include:

- a) the **Over-the-Counter (OTC) Market**: buying and selling of electricity (energy and capacity or only energy) for the medium and long-term through **Bilateral Contracts**.
- b) the **Day-Ahead Market (DAM)**: buying and selling of energy in short-term transactions in a centralized market.
- c) subsequently, the intra-day market and **Ancillary Service** market.

MC 2.3.2 *Over-The-Counter Market (OTC)*

MC 2.3.2.1 **Over-the-Counter (OTC) Market** is the type of market in the REM based on **Bilateral Contracts**, where **Market Participants** are free to negotiate and conclude **Bilateral Contracts** for electricity

MC 2.3.2.2 Transactions in the **OTC Market** must be **Cross-Border Transactions** to be deemed transactions under the scope of the **Market Code**. A **Cross-Border Transaction** means that the **Seller** must sell electricity supplied or generated from **Facilities** operating within a **Member State** to a **Buyer** that purchases the electricity and is located in a different **Member State** from the **Member State** where that **Seller** is located.

MC 2.3.3 *Centralized Day-Ahead Market (DAM)*

MC 2.3.3.1 In this **Market Code**, the DAM is the short-term centralised market in which the transactions in each trading day are concluded for each **Market Time Unit** of the **Delivery Day**, based on the **Offers** and **Bids** submitted by the **DAM** participants.

MC 2.3.3.2 The **Offers** and **Bids** in the **DAM** shall be performed by the aggregation of **Generation** and **Load** portfolios.

MC 2.3.3.3 The **SMO** shall operate the **DAM** and act as the sole counterparty to the **Market Participants** for all sale and purchase transactions.

MC 2.3.3.4 The transactions on the **DAM** shall be executed through an internet-based electronic platform, called the **Energy Trading System**, under the responsibility of the **SMO**.

MC 2.3.3.5 Transactions in the **Day-Ahead Market (DAM)** are considered **Cross-Border Transactions** as they are facilitated by the **System Market Operator (SMO)** which is the sole counterparty to any transaction in the centralised market.

MC 2.3.4 ***Additional Markets in the REM***

MC 2.3.4.1 Based on the evolution of the **REM**, the competitiveness, the liquidity and the **Regional** requirements, additional type of markets may be proposed and developed by the **SMO and WAPP** and approved by **ERERA**. The provisions of these markets shall be part of the **Market Code**.

MC 2.3.5 ***Currency***

MC 2.3.5.1 Trades in the **REM** shall be conducted in United States of America dollars (USD) or as determined by **ERERA**. Accordingly, the financial **Settlement** of the trades as well as trades in energy financial instruments registered on the **Energy Trading System** shall also be in USD or as determined by **ERERA**.

MC 2.4 **Governance of the REM**

MC 2.4.1 ***Governing structure of the REM***

MC 2.4.1.1 The governing structure of the **REM** comprises:

- a) **ERERA, WAPP** and the **SMO**, in charge of ensuring compliance with and implementation of the **REMR**; and
- b) The national **System Operators, Transmission Operators** and national **Market Operators** of each **Member State**, as far as they participate in the operation of the **Regional Electricity Market**.

MC 2.4.2 ***ECOWAS Regional Electricity Regulatory Authority (ERERA)***

MC 2.4.2.1 The **ECOWAS Regional Electricity Regulatory Authority (ERERA)** is the **Regional Institution** responsible for regulating cross-border electricity trade in the **West Africa Power Pool**. **ERERA** has the mandate to rule, supervise and monitor the functioning of the **Regional Electricity Market (REM)**.

MC 2.4.2.2 **ERERA**, at the minimum, is in charge of:

- a) the issuance of the authorisation to participate in the **REM**
- b) the surveillance of the **REM** by ensuring the implementation of the **REMR**
- c) the sanctioning of violations of the rules of functioning of the **REM**,
- d) the **Settlement of Disputes** among the **Market Actors**.

MC 2.4.3 ***West African Power Pool (WAPP)***

MC 2.4.3.1 The **West African Power Pool (WAPP)** organization is the **Regional Institution** responsible for planning, monitoring and facilitating the development of the **Regional Electricity Market (REM)**.

MC 2.4.3.2 **WAPP organization**, at the minimum, is in charge of:

- a) coordinating and harmonizing of the priority plan and infrastructure development plan of the **REM's**,
- b) ensuring continuous harmonization process between national and **Regional** planning,
- c) Assisting operators in improving the performance of utilities in the management and development of the **WAPPITS**.
- d) Initiating and recommending to **ERERA** rules and procedures for the proper functioning and development of the **REM**.

MC 2.4.4 **National Regulatory Authorities (NRA)**

MC 2.4.4.1 The **National Regulatory Authorities (NRA)** are national institutions in the **Member States** that ensure the proper functioning, balance, transparency and sustainability of the electricity sector while ensuring equitable access to electricity.

MC 2.4.4.2 **NRAs**, at the minimum, are in charge of:

- a) Ensuring the compliance of **Market Actors** with **REMR**
- b) Ensuring, in relation with **ERERA**, that national regulations are in harmony with the regulation of cross-border exchanges of electricity,
- c) Assisting **ERERA** in the process of developing and adopting the **REM** regulations and procedures
- d) Issuing import and/or export licence at the national level.
- e) Taking the necessary measures to facilitate fulfilment of financial commitments in the **REM**.

MC 2.4.5 **System and Market Operator (SMO)**

MC 2.4.5.1 The System and Market Operator (SMO) is the Regional Institution responsible for operating the Regional Electricity Market (REM) and coordinating the operation of the Power Systems within the WAPPITS.

MC 2.4.5.2 The **SMO** is in charge of:

- a) Day-to-day management of the **OTC Market**, the **Day-Ahead Market**, the intra-day market and the **Ancillary Service** market.
- b) Co-ordination with **Grid Operators** for the use of interconnectors and to optimise this use

- c) Settlement of the commercial transaction in the **REM** and the collection of **Market Fees**.
- d) Assist **ERERA** in the surveillance and monitoring of the market.

MC 2.5 The System and Market Operator (SMO) Functions

MC 2.5.1 *Functions and Responsibilities of the SMO*

MC 2.5.1.1 The **SMO** directs and coordinates the technical operation of the **REM** and carries out its commercial management with technical and economic criteria according to the **REMR** .

MC 2.5.1.2 The **SMO**'s specific activities are to:

- a) Monitor load flows and take action on variances (coordinate with the **System Operators** to maintain the power flows);
- b) Allocate the cross-border **Available Transfer Capacity (ATC)**;
- c) Schedule the traded volumes from the **REM** on the **Cross-border Interconnections**;
- d) Monitor the exchange of scheduled power at each border;
- e) Undertake **Settlement of Imbalances**;
- f) Manage **Collateral** requirements and payments for the **Market Participants** according to the agreed rules;
- g) Manage payments to or from the **Market Participants** within the stipulated timelines;
- h) Keep transaction records;
- i) Carry out operational planning of the **Cross-border Interconnections**;
- j) Coordinate congestion management;
- k) Conduct Market Monitoring and surveillance;
- l) Manage **Dispute** at an operational level in the first instance;
- m) Manage the **OTC Market** and the **Day-Ahead Market**;
- n) Administer **Meter** reading ;
- o) Manage the **Settlement**, billing and payment processes;
- p) Administer the required IT infrastructure for market activities;
- q) Collaborate with other **Regional Institutions**.

MC 2.5.2 *Delegation*

MC 2.5.2.1 The **SMO** may delegate any of its functions under the **Market Code** to an **Entity** or a competent and approved third party to exercise the said functions. Such delegation shall be with the prior approval of **ERERA**. A function performed by a delegate third-party is to be taken as being performed by the **SMO**.

MC 2.5.3 *Reporting*

MC 2.5.3.1 The **SMO** shall report to **ERERA**. As such the **SMO** shall provide the following reports to **ERERA** with a copy to **WAPP**:

- a) An annual report of activities including market performance, financial statements, and operational **Disputes** no later than June 30 of the following year;
- b) A summarized report on market evolution to be produced every four (4) months;

MC 2.5.3.2 **ERERA** may require the **SMO** the provision of any other report on specific issues.;

MC 2.5.3.3 **The** reports mentioned in this MC 2.5.3 as well as any other non-confidential report necessary for the proper functioning of the market will be made available to **Market Actors** by the **SMO** through its website.

MC 2.5.3.4 **The SMO** indicative reporting deadlines over a calendar year is specified in ANNEX E 3.

MC 2.5.4 *Databases to be Developed and Maintained by the SMO*

MC 2.5.4.1 The **SMO** shall develop, maintain and administer a **Regional Database** structured according to an integrated data model, which shall contain all the **Information** necessary for the fulfilment of its functions and the recording of **Regional Electricity Market** results and developments for stakeholders' **Information**.

MC 2.5.4.2 The **Information** to be contained in the **Regional Database** is set out in the **Market Code**, and such **Information** are provided by relevant **Market Actors** to the **SMO** for the execution of its functions and the fulfilment of its responsibilities. The handling of and access to all **Information** contained in the **Regional Database** shall follow the provisions set out in MC 1.6.

MC 2.5.4.3 The structure of the **Regional Database** shall, at least, provide for the organization of the **Information** in a trading database and an operational database. The database shall contain all the data necessary for the administration of the **REM**, operational planning, operational security studies and the coordinated operation of the **Regional Electricity Market** by the **SMO**, under the provisions of the **REM Codes**.

MC 2.5.4.4 The **Regional Database** will allow the storage, processing, registration, and exchange of relevant **Information** for the development of at least the following processes of the **Regional Electricity Market**:

- a) **Bilateral Contracts** and commercial transactions;
- b) **Cross-border Interconnection** flows;

- c) **Metering**;
- d) Real-time operation;
- e) Reconciliation, invoicing and **Settlement** of transactions;
- f) **Outage Planning Coordination Business Process** and operational security;
- g) Regional expansion planning;
- h) Regional transmission system planning;
- i) Market monitoring and surveillance; and
- j) Historical **Information** from the exchange of **Information** between **System Operators**.
- k) Database on **WAPPITS** Assets.

MC 2.5.4.5 The Regional Database will be updated mainly with Information produced by the SMO, Information provided by the System Operators, Information acquired through SCADA and Information from other Market Actors. The Information provided by Market Participants will be sent through their System Operators. The deadlines for updating the Information in the Regional Database shall be those defined in the Market Code.

MC 2.5.4.6 The **SMO**, after consultation with the **System Operators** and **Market Participants**, shall develop an **Operational Procedure** for communication and exchange of **Information** with the **System Operators** and **Market Participants**, specifying the type, format, and timing of the **Information** to be provided. The **SMO** may periodically review and revise the **Operational Procedure** for communication, after consultation with the **System Operators** and **Market Participants**.

MC 2.5.4.7 Regarding the **Information** provided by the **System Operators** and **Market Participants** to the **Regional Database**, the **SMO** shall perform an **Operational Procedure** for review and objection of the **Information**, to verify the **Information**'s consistency and identify transcription and reporting errors. In any case, the **System Operators** and **Market Participants** will be responsible for the **Information** provided.

MC 2.5.4.8 The **SMO** shall maintain a legal and regulatory database as part of the **Regional Database** that includes **ECOWAS** decisions, directives, regulations, and protocols, **ERERA's** regulations and decisions, and the associated technical decisions taken by **WAPP**. It shall also maintain the **Market Monitoring Report** in the **Regional Database**.

MC 2.5.4.9 The **SMO** shall provide access to its **Regional Database** in accordance with access control and security protocols as specified in MC 1.6.4.

MC 2.5.5 **Market Monitoring**

MC 2.5.5.1 The **SMO** shall develop the **Operational Procedure** for market monitoring called **Market Monitoring Procedure** and submit to **ERERA** for approval.

MC 2.5.5.2 The purpose of the **Market Monitoring Procedure** is to establish the mechanism by which the **SMO** shall ensure that all **Market Participants** comply with the **Market Code**.

MC 2.5.5.3 The Market Monitoring Procedure shall specify:

- a) The **SMO**'s monitoring processes for assessing compliance by all **Market Participants** with the **Market Code**;
- b) A process for **Market Participants** to report alleged breaches of the **Market Code**;
- c) Processes for investigations into alleged breaches of the **Market Code**;
- d) Guidelines for the **SMO** when issuing warnings about breaches by **Market Participants** to the **Market Code**; and
- e) The procedure for submitting complaints and reports on **Market Code** breaches in accordance with **ERERA**'s Enforcement Rules or **Dispute** resolution procedures.

MC 2.5.5.4 Where breaches in the **Market Code** have been identified, or there is a reasonable or compelling evidence that the **Market Code** has been breached, all documentation on the matter shall be referred to **ERERA** for determination and to take the necessary action.

MC 2.5.5.5 The **SMO** shall prepare and submit quarterly **Market Monitoring Report** to **ERERA**

MC 2.5.6 **Market Audit**

MC 2.5.6.1 The **SMO** shall, annually, appoint a competent and qualified Auditor(s) to conduct market audit in accordance with MC 25.1.1

MC 2.5.7 **Financial Audit**

MC 2.5.7.1 The **SMO** shall, annually, appoint one (1) or several competent Auditor(s) to conduct financial audit in accordance with article MC 25.1.1.1.

MC 2.6 **The Grid Operator, System Operator and Transmission Operator**

MC 2.6.1 **Roles of the Grid Operator, System Operator and Transmission Operator**

MC 2.6.1.1 For **Operational** purposes, **WAPP** is organized in **Control Areas** and each **Control Area** is managed by a **Grid Operator**.

MC 2.6.1.2 The **Grid Operator** executes the functions and activities performed by the **System Operator** and the **Transmission Operator**. In the **Market Code**, when referring to a **Grid Operator**, the term should consider both functions: **System Operator** and **Transmission Operator**.

MC 2.6.1.3 When referring to a **System Operator**, the attributes and functions to be performed by a **System Operator** pertain to the **Functional Operation** of the **Power System** and the **Cross-**

border Interconnection. These attributes and functions do not involve the **Physical Operation** and maintenance of the **Transmission System** assets.

MC 2.6.1.4 When referring to a **Transmission Operator**, the attributes, and functions to be performed by a **Transmission Operator pertain to** the **Physical Operation**, the security and maintenance of their own **Transmission System** assets.

MC 2.6.2 ***Rights of System Operator and Transmission Operator***

MC 2.6.2.1 A **Transmission Operator** shall be remunerated for the use of its transmission assets that are part of the **WAPPITS**.

MC 2.6.2.2 A **System Operator** shall be remunerated for the services provided for the **Functional Operation** of the system, for the stability, security and operation of the **WAPP Power System**.

MC 2.6.3 ***Duties of the Grid Operator, System Operator and Transmission Operator***

MC 2.6.3.1 The **System Operators** perform **Functional Operation**, and the **SMO** coordinate their activities related to the **REM**.

MC 2.6.3.2 A **Grid Operator** designated as a **Regional Compensation Party (RCP)** shall pay the compensation charges allocated to it in the implementation of the **Regional Transmission Tariff Methodology (RTTM)**.

MC 2.6.3.3 Regarding the **REM**, the functions of the **System Operator** include:

- a) Ensuring safe operation within the **Control Area**;
- b) Collaborating with the **SMO** in the operational planning of the **Cross-border Interconnections**;
- c) Maintaining the flows in the interconnection lines according to the schedule;
- d) Maintaining constant communication with the **SMO** to ensure the scheduled power flows in the **Cross-border Interconnections**;
- e) Coordinating with neighbouring **Control Areas** in case of **Emergency** within a particular **Control Area**.
- f) Complying with the **Operational Procedure** for restoration in case of **Emergency** within the **Control Area** that requires re-energization from external **Control Area** (see **Operation Code OC 4.5**).

MC 2.6.4 ***Admission of a Grid Operator***

MC 2.6.4.1 **NRAs** shall communicate to **ERERA** and the **SMO** the **Grid Operators** of their respective countries.

MC 2.6.4.2 A **Grid Operator** shall be ex-officio subject to the provisions of the **REM Codes** by virtue of its designation.

MC 2.6.4.3 A **Grid Operator** shall sign an operational coordination agreement with the **SMO** which shall be approved by **ERERA**.

MC 2.6.4.4 A **Grid Operator** may be a vertically integrated company. A vertically integrated company is subject to specific ring-fencing rules as set out in MC 2.7.9

MC 2.6.4.5 In accordance with article MC 2.7.9.5, the vertically integrated company shall set up a separate unit to manage the **Functional Operation** activities.

MC 2.7 Regional Electricity Market (REM) Participation

MC 2.7.1 General Conditions of Participation in the REM

MC 2.7.1.1 Any **Applicant** seeking to carry out transactions in the **REM** shall be authorized by **ERERA**. For this purpose, the **Applicant** shall submit to **ERERA** the following:

- a) Application form for authorization to participate in the **REM**;
- b) Proof of being duly licensed to participate in international transactions (import and export), issued by the competent national authority.
- c) Attestation certificate, according to the type of **Market Participant**, issued by the **SMO** certifying compliance of the Applicant with the applicable technical requirements set in MC 2.7.2.

MC 2.7.1.2 The detailed procedure for application for authorization to participate in the **REM** shall be established by **ERERA** and attached in **Annex A** of the **Market Code**.

MC 2.7.1.3 The procedure for granting import and export license by the competent authority in each **Member State** shall follow the directive for the harmonization for the granting of licences and authorizations to participate in the **REM**.

MC 2.7.1.4 The detailed procedure for application for the attestation of compliance with technical requirements to participate in the **REM**, shall be developed by the **SMO** and approved by **ERERA**.

MC 2.7.1.5 **ERERA** may request further clarification from the **Applicant**, the **SMO** or the **NRA** of the **Applicant's** country to facilitate the review of the application for authorization.

MC 2.7.1.6 Within a maximum period of sixty (60) **Days** from receipt of an application for the attestation of compliance with technical requirements to participate in the **REM**, the **SMO** shall issue an attestation certificate to the **Applicant**, with a copy to **ERERA**, certifying compliance or non-compliance with the applicable technical requirements.

MC 2.7.1.7 Within a maximum period of thirty (30) **Days** from receipt of a complete application to participate in the **REM**, **ERERA** shall issue a decision by resolution either authorizing the

Applicant to carry out transactions in the REM and notifying the **SMO** and the **Applicant** or, if the **Applicant** has not complied with the requirements of the **REM Codes**, deny the request to trade and provide written justification and notifying the **SMO** and the **Applicant** accordingly.

MC 2.7.1.8 Any **Entity** from the **Electricity Supply Industry** who intends to inject or withdraw energy from or to a **Power System** outside the **WAPPITS** must also apply for authorization by **ERERA** to participate in the **REM**.

MC 2.7.2 *Technical Conditions for Market Participation*

MC 2.7.2.1 To be authorized by **ERERA** to carry out energy injection or withdrawal transactions in the **REM**, the **Applicant** shall apply and obtain an attestation certificate from the **SMO** certifying the **Applicant's** compliance with the Technical Conditions for Market Participation

MC 2.7.2.2 The following technical conditions for Market Participation are indispensable:

- a) The equipment and **Facilities** of the **Applicant** connected to the **WAPPITS** shall comply with the applicable technical requirements, design standards for **Facilities** and commercial metering requirements set out in the **REM Codes**.
- b) The **Applicant** must have the means of communication (telephone, internet, email, mobile communications, etc.), as defined by the **SMO**, for the operational coordination with the **SMO** and with the relevant **Grid Operators**, as established by the **Operation Code**.
- c) The **Metering Equipment** must be installed according to the **Metering Code** at each **defined Metering Point**, at each **Injection Points** for the **Sellers** and each **Withdrawal Points** for the **Buyers**;
- d) The **Metering Equipment** installed shall be registered with the **SMO**, following the provisions of the **REM Codes**; and
- e) The **SMO** has the due authorization and access to read the **Metering Equipment** installed at the **Defined Metering Points** of the **Cross-border Interconnections** remotely and be able to do it before the transactions start, while for the **Injection Points** and **Withdrawal Points**, the **SMO** will have to receive the measurements and signals from the **Grid Operators**, as required in the **Connection Code**.
- f) Where required, the **Applicant** shall have the capability to send **SCADA** signals, to the **SMO**, with the variables and parameters defined by the **SMO** and approved by **ERERA**, in order to monitor and functionally operate the **WAPPITS**.

MC 2.7.2.3 The **SMO** may request the technical opinion of the **Grid Operator** of the **Applicant's** country to facilitate assessment of the **Applicant's** compliance with the technical conditions for market participation.

MC 2.7.3 *Registration of Market Participant*

MC 2.7.3.1 An **Entity**, from the **Electricity Supply Industry**, that intends to participate in the **REM**, must apply to **ERERA** for registration as a **Market Participant**.

MC 2.7.3.2 An **Entity** from the **Electricity Supply Industry** that intends to inject or withdraw energy from or to a **Power System** outside the **WAPPITS** must also apply to the **SMO** for registration as a **Market Participant** in the **REM**.

MC 2.7.3.3 An **Applicant** authorized by **ERERA** to participate in the **REM** shall be registered as a **Market Participant** in the **REM** and be issued a unique identification number as **Market Participant**.

MC 2.7.3.4 **ERERA** shall establish, maintain, update and **Publish** a **Market Participants'** register containing:

- a) A list of all **Market Participants** with their contact **Information**;
- b) A list of suspended **Market Participants** from the **REM**, the time from which their rights were suspended and the period of **Suspension**;
- c) A list of **Market Participants** withdrawn from the **REM** updated to the last month and containing the date from which they ceased their participation in the **REM**;
- d) A list of all **Market Participants** that withdrew from the **REM** and the date of cessation of their participation in the **REM**;
- e) A list of all **Market Participants** that will cease to trade on the **REM** and the date they will cease participating in the **REM**.

MC 2.7.4 ***Rights of a Market Participant***

MC 2.7.4.1 A **Market Participant** shall have the right to:

- a) buy and/or sell electricity in the **REM** freely and without discrimination in accordance with applicable national and **Regional** regulations.
- b) request through its **Grid Operator**, within the time limits established in the **Market Code**, that the **SMO** reviews the results of any commercial transaction in which the **Market Participant** believes that a calculation or an application error was made.
- c) submit to the **SMO**, proposals for amendments to the **Market Code**, and to be consulted on proposals from other **Market Participants**;
- d) present to the **SMO**, an appeal for reconsideration of the actions or inactions of the **SMO** which affect it in particular;
- e) refer to **ERERA**, in accordance with MC 26, for **Dispute** resolution;
- f) due process in the event of investigations carried out by **ERERA**.

MC 2.7.5 ***Obligations of a Market Participant***

MC 2.7.5.1 A **Market Participant** shall:

- a) Pay to the **SMO**, the market fees as prescribed in the **REM Regulation**;
- b) Allow access to its **Facilities** by representatives designated by the **SMO** or **ERERA** to carry out inspections and audits as set out in the **Market Code**;
- c) Comply with the monitoring, control, communications and trade measurement requirements set out in the **REM Codes**;
- d) Carry out, in coordination with its **Grid Operator**, the technical tests and inspections required by the **SMO**;
- e) Carry out operations including switching of its own equipment under the provisions of the **REM Codes**, following the instructions of its **Grid Operator** under the coordination of the **SMO**;
- f) Provide and maintain the amounts of payment guarantees required under the **REM Codes** and notify the **SMO** and the **Grid Operator** of any changes to the conditions of the guarantees;
- g) Comply with the penalties and pay the fines imposed by the **SMO** and/or **ERERA**, as provided for in the **REM Regulation**;
- h) Maintain and deliver to its **Grid Operator** and the **SMO** all the **Information** required in the **Market Code**.
- i) Have a balancing agreement with its **Grid Operator**

MC 2.7.5.2 By its registration to participate in the **REM**, the **Market Participant** acknowledges and accepts that the **SMO** shall have the power to represent it before the other **Market Participants**, the **Grid Operators** and **ERERA** for reconciliation, invoicing and **Settlement** of commercial transactions and other payment obligations in the **REM**, in accordance with the provisions of the **Market Code**.

MC 2.7.5.3 The **Market Participant** shall sign with the **SMO** the relevant participation agreement to participate in the type of market of their choice in the **REM**.

MC 2.7.6 *Requirements to stop trading in the REM*

MC 2.7.6.1 A **Market Participant** who decides to stop trading in the **REM** shall notify the **SMO** and **ERERA** in writing. This notification shall include the declaration of its decision to stop trading in the **REM** and the date on which it intends to stop trading in the **REM**.

MC 2.7.6.2 After receiving the notification referred to in article MC 2.7.6.1, the **SMO** shall inform the **Grid Operators**, and other **Market Participants**.

MC 2.7.6.3 Subject to articles MC 2.7.6.1 and MC 2.7.6.2 the **Market Participant** shall cease to trade in the **REM** on the date specified in the notification given under article MC 2.7.6.1, which shall not be less than three (3) months from the date of acknowledgement of receipt of the notification by the **SMO** or the date of the last transaction carried out by the **Market Participant**, whichever is the latest.

MC 2.7.6.4 A **Market Participant** that has sent a notification following article MC 2.7.6.1 may stop making transactions in the **REM** if it has made all the payments to be made by it or on its behalf in accordance with the **Market Code**; until such payments are made, the payment guarantees shall remain in force.

MC 2.7.6.5 If, for any reason, the **Market Participant** stops trading in the **REM**, the **SMO** shall invoice and ensure the **Settlement** of any balances in favour or against the **Market Participant**. The decision to stop trading in the **REM** shall not prevent the **Market Participant** from discharging its financial obligation of service charges in the **REM**.

MC 2.7.6.6 After the necessary verifications, the **SMO** shall inform **Market Actors** of the cessation to trade by the **Market participant**.

MC 2.7.6.7 The **Market Participant** retains the right to resume trading at any time subject to satisfying all the necessary conditions for participation in the **REM**.

MC 2.7.7 ***Withdrawal of Market Participants***

MC 2.7.7.1 A **Market Participant** seeking to withdraw from the **REM** shall notify the **SMO** and **ERERA** in writing. This notification shall include the declaration of its decision to withdraw from the **REM** and the date on which it intends to withdraw from the **REM**. The **SMO** shall be **responsible** for terminating the participation of the **Market Participant** in the **REM**, and **ERERA** shall be responsible for the formal withdrawal of the **Market Participant**.

MC 2.7.7.2 Upon receipt of the notification, referred to in article MC 2.7.7.1, the **SMO** shall inform the **System Operators**, and **Publish** the receipt of the notification of the market participant to withdraw from the **REM** on the date specified in the notification.

MC 2.7.7.3 Subject to articles MC 2.7.7.1 and MC 2.7.7.2, the **Market Participant** shall cease its participation in the **REM** on the date specified in the notification given under article MC 2.7.7.1, which shall not be less than three (3) months from the date of acknowledgement of receipt of the notification by the **SMO** or the date of the last transaction carried out by the **Market Participant**, whichever is the latest. Nevertheless, where the **Market Participant's** participation ceases, its status shall remain until **ERERA** formally declares its withdrawal.

MC 2.7.7.4 A **Market Participant** that has sent a notification according to article MC 2.7.7.1 may only formally withdraw from the **REM** when it has made all the payments to be made by it or on its behalf in accordance with the **Market Code**. The payment guarantees referred to in the **Market Code** shall remain in force until such payments are made.

MC 2.7.7.5 The **SMO** shall notify **ERERA** within three (3) working days that all payments and liabilities have been cleared so that **ERERA** can formally declare the withdrawal.

MC 2.7.8 ***Suspension of Market Participants***

MC 2.7.8.1 If a **Market Participant** commits violations according MC 23 and after due process, **ERERA** may issue a **Suspension** of that **Market Participant** from the **REM**. The participation of such

Market Participant will be suspended for the period specified in the **ERERA**'s order or until **ERERA** notifies that the order has been revoked.

MC 2.7.8.2 Once the **Suspension** of a **Market Participant** is issued, **ERERA** shall **Publish** the order according to MC 2.7.8.1 , notify the suspended **Market Participant** and inform the **SMO** and the relevant **Grid Operator** of the **Market Participant's Suspension**.

MC 2.7.8.3 The **Suspension** shall take effect the **Day** after the notification under article MC 2.7.8.2, and the **Market Participant's** participation in the **REM** shall be suspended in the manner specified in the order of **ERERA**. The suspension may apply to one or more of the rights set out in article MC 2.7.8.2.

MC 2.7.8.4 A **Market Participant** that has been suspended from the **REM** shall remain subject to all obligations and liabilities it has under the **Market Code**.

MC 2.7.9 *Provision Related to Vertically Integrated Companies*

MC 2.7.9.1 Given the different unbundling status of the electricity sector within all the **Member States**, the **Market Code** acknowledges that some **Market Participants** can be vertically integrated companies, which implies that they are ex-officio **Market Actor** in the **REM** because of their role as **Grid Operators**.

MC 2.7.9.2 To favour the transparency in the **REM** and prevent anti-hoarding and anti-competitive practices, the **Market Code** sets out the specific provisions for vertically integrated companies.

MC 2.7.9.3 A vertically integrated company shall establish a separate strategic business unit to act as **Market Participant** according to the provisions set for in article MC 2.7.4 and MC 2.7.5. The vertically integrated company shall develop a formal communication protocol to manage communication between the separate unit and the unit responsible for **Grid** operation. **ERERA** shall validate this protocol as a prerequisite for authorisation of the vertically integrated company to participate in the **REM**.

MC 2.7.9.4 The separate strategic business unit referred to MC 2.7.9.3 shall apply to **ERERA** to be authorized to participate in the **REM** through the vertically integrated company.

MC 2.7.9.5 The strategic business unit, through the vertically integrated company, shall

- a) Appoint one (1) or more representatives that cannot be involved in **Grid** operations activities, as long as they represent the unit operating in the **REM**;
- b) Create a separate management and accounting system to manage and record all the activities related to the **Regional** transactions;
- c) Keep ring-fenced **Information** confidential;
- d) Establish and maintain appropriate internal processes to ensure it complies with its obligations under the **Market Code**. **ERERA** shall require the unit and the vertically integrated company to demonstrate the adequacy of these processes upon reasonable notice;

- e) Prepare an annual ring-fencing compliance report each calendar year.
- f) Submit the annual Ring-Fencing Compliance Report to **ERERA** within four (4) months of the end of the calendar year to which the compliance report relates.

MC 2.7.10 *Monitoring and Surveillance of the level of ring-fencing of vertically integrated companies*

MC 2.7.10.1 **ERERA** has the mandate to monitor the compliance of the vertically integrated companies to the provisions set out in MC 2.7.9.

MC 2.7.10.2 **ERERA** shall prepare an annual Ring-Fencing Monitoring Report each calendar year, which shall contain all relevant **Information** on the compliance of the vertically integrated companies.

MC 2.7.10.3 With an appropriate regulatory decision, **ERERA** shall set higher levels of ring-fencing requirements, as long as they comply with the provisions set forth in the **Market Code**.

TITLE II – OVER THE COUNTER MARKET

MC 3. OVER THE COUNTER MARKET (OTC) PRINCIPLES

MC 3.1 Characteristics of the Regional OTC Market

MC 3.1.1 The **OTC Market** has the following main characteristics:

- a) Trading on the **OTC Market** shall be mandatory for a **Market Participant** who voluntarily elect to perform a **Bilateral Contract** with another **Market Participant**.
- b) The negotiations to enter into a **Bilateral Contract** shall be carried out directly between the contracting **Parties**, without the involvement of the **SMO**.
- c) A **Bilateral Contract** shall comply with the applicable national regulations and the **REM Regulation**.
- d) The electricity traded in the **OTC Market** is just for physical delivery.
- e) The tradable products in the **OTC Market** are energy and capacity or only energy.

MC 3.2 Allocation of Capacity in the OTC Market

MC 3.2.1 The total allocated capacity in the **OTC Market** shall be the **Net Transfer Capacity (NTC)** determined in accordance with the procedures outlined in the **Operation Code**.

MC 3.2.2 The **SMO** shall periodically **Publish** the **OTC Market** timeline. **ANNEX E** provides an illustration of the indicative **OTC Market** timeline based on the provisions of the **Market Code**.

MC 3.3 Duration of the OTC Market Bilateral Agreements

MC 3.3.1 The **Bilateral Contracts** that shall be registered in the **OTC Market** are:

- a) Long-term **Bilateral Contracts** with a duration equal to or higher than one (1) year.
- b) Medium-term **Bilateral Contracts** with a duration equal or higher than one (1) month and lower than one (1) year.

MC 3.3.2 Depending on the evolution of the market, **ERERA** may authorize a reduction in the minimum duration of the **OTC Market Bilateral Contracts** by introducing the possibility of **Bilateral Contracts** with a duration shorter than one (1) month.

MC 4. PARTICIPATION IN OTC MARKET

MC 4.1 Conditions for Participation in the OTC Market

MC 4.1.1 To participate in the **OTC Market**, an **Entity** of the **Electricity Supply Industry** shall apply be authorized and registered by **ERERA** as **Market Participant** in the **REM**.

MC 4.1.2 Upon registration by **ERERA**, a **Market Participant**, shall be entitled to:

- a) trade in the **OTC Market** in **accordance** with the **Market Code**, subject to the execution of an **OTC Market** participation agreement with the **SMO**
- b) have access to **Information** made available by **ERERA** and **SMO** for **Market Participants**

MC 4.1.3 The **Bilateral Contracts** entered into by **Market Participants** shall comply with the model **Bilateral Contract** as approved by **ERERA** and attached in Annex B of the **Market Code**.

MC 4.2 Responsibilities of Market Participants in the OTC Market

MC 4.2.1 A **Market Participant** in the **OTC Market** shall be responsible for submission and receipt of data in the **Information** exchange process with the **SMO**, particularly such as:

- a) Supply schedules according to their **Bilateral Contracts**, agreements and pre-existing obligations prior to the commencement of the **Regional Electricity Market** or under the **OTC Market** framework.
- b) Declarations of availability (for generators and suppliers) and **Load** declarations (for **Loads**).
- c) Commercial **Information** concerning prices, **Settlements** and payments associated with contracts and any other relevant data may be reasonably required by the **SMO** and **ERERA**.
- d) The contract prices in the **OTC Market** declared to the **SMO** and **ERERA** shall be kept confidential by the later in accordance with MC 25.2.4.
- e) Where a **Party** to a **Bilateral Contract** is a **Market Participant** responsible for supplying electricity to the end-users of a country or a **Region**, such **Market Participant** shall report the agreed prices to **ERERA** and its **NRA**.

MC 4.3 Participation in the OTC Market

MC 4.3.1 A **Market Participant** who holds an existing **Power Purchase Agreement (PPA)** or **Bilateral Contract** or wants to export or import power without a current bilateral agreement, must be registered on the **OTC Market**.

MC 4.3.2 **Market Participant** may designate one or more **Certified Traders** (MC 13.2) to act on its behalf to trade in the **OTC Market**.

MC 5. CONTRACTS IN THE OTC MARKET AND OTC PLATFORM

MC 5.1 Contracts transacted in the OTC Market

MC 5.1.1 The scheduling of contracts in the **OTC Market** shall be made according to the following:

- a) **Grandfathered Contracts**;
- b) **First-Come-First-Served** or **Explicit Auction** as determined by the **SMO**.

MC 5.1.2 The execution of a **Bilateral Contract** transacted in the **OTC Market** shall only be by physical delivery of electricity.

MC 5.1.3 A clause in a **Bilateral Contract** that do not comply with any provision in the **Market Code** is not considered valid in the **OTC Market**.

MC 5.2 Injection Point and Withdrawal Point in the OTC Market

MC 5.2.1 The energy quantities included in the **Bilateral Contracts** correspond with electricity injections from the **Seller** at a defined contractual **Injection Point** and the electricity withdrawal from the **Buyer** at a defined contractual **Withdrawal Point**.

MC 5.2.2 The **Sellers** and **Buyers** shall be responsible for the energy losses arising from the transactions between the **Injection Point(s)** to the **Withdrawal Point(s)**.

MC 5.2.3 **Metering Equipment** shall be installed and maintained in each **Injection Point**, **Withdrawal Point** and **Defined Metering Point** of a **Cross-border Interconnection** to measure the power flows. The procurement, ownership, installation and maintenance of the **Metering Equipment** shall be the responsibility of the **Transmission Operator**, as established in the **Metering Code**.

MC 5.3 OTC Market Platform

MC 5.3.1 The **OTC Platform**, implemented by the **SMO**, shall be the official platform to register the **Market Participants** in the **OTC Market** under the **Market Code**.

MC 5.3.2 The objectives of the **OTC Platform** shall be:

- a) To provide **Information** on potential **Buyers** and **Sellers** of electricity;
- b) To maintain a repository of data related to **Buyers** and **Sellers** and provide such historical data to **Market Participants**;

- c) To provide such services as advanced data analysis tools to **Market Participants**;
- d) To enable the **SMO** manage the **OTC Market**.

MC 5.3.3 Access to the **OTC Market Platform** shall be granted:

- a) to **Market Participants** registered in the **OTC Market**,
- b) to **ERERA**

MC 5.4 Registration in the OTC Platform

MC 5.4.1 A **Market Participant** shall perform the registration to operate in the **OTC Platform**. The following process shall be followed for filing application and grant of registration:

- a) The registration shall be filed online on the website of the **SMO**, following the **SMO** defined guidelines for registration.
- b) The **SMO** shall, after consideration of the proposal and making such inquiries as may be necessary, either grant registration or reject the registration application.
- c) Once granted, the registration on the **OTC Platform** shall continue to be in force for a period of five (5) years from the date of grant of registration unless such registration is revoked or cancelled earlier.
- d) The **SMO** shall, on an application filed on the **OTC Platform**, and after making such inquiries as may be necessary, renew registration for a further period of five (5) years.
- e) Any **Market Participant** granted registration by the **SMO** to operate on the **OTC Platform** according to this **Market Code**, shall pay an annual registration charge in accordance with the timeline and the manner specified in MC 20.

MC 5.4.2 The documents to be submitted for registering in the **OTC Platform** shall include the following:

- a) the identity of the **Market Participant**;
- b) The **Bilateral Contract**;
- c) The account number.

MC 5.5 Restrictions of Use of the OTC Platform

MC 5.5.1 The **OTC Platform** shall not be used for negotiation, execution, clearance or **Settlement** of the contracts.

MC 5.5.2 The **OTC Platform** shall be neutral and not influence the trading decision making of the **Market Participants** in any manner.

MC 5.6 Revocation of Registration on the OTC Platform

MC 5.6.1 **ERERA**, on its own initiative or upon the proposal by the **SMO**, and after hearing the concerned **Market Participant**, may revoke the registration of the **Market Participant** on the **OTC Platform**. The decision to revoke must be justified and recorded.

MC 6. ALLOCATION OF THE TRANSMISSION CAPACITY IN THE OTC MARKET

MC 6.1 Timeframes for Capacity Allocation

- MC 6.1.1 The **SMO** shall establish timeframes for the allocation of the available capacity in different time periods to allow **Market Participants** to negotiate different contracts in order to hedge the risks of availability of capacity in the **REM**. The allocation of firm capacity shall be performed over multi-year, yearly and monthly periods. An allocation of capacity on weekly or daily basis is non-firm.
- MC 6.1.2 The multi-yearly and yearly allocation of capacity shall be deemed long-term and the monthly allocation of capacity shall be deemed the medium-term. A weekly or daily allocation of capacity shall be deemed short-term.
- MC 6.1.3 The total volume of long-term capacity made available for allocation in a timeframe shall not exceed the **NTC** for that respective timeframe. Therefore, the **NTC** calculation shall also be performed for the defined timeframes in article MC 6.1.1.
- MC 6.1.4 Every contract must contain detailed **Information** of the timeframe for the capacity negotiated, and the date of the allocation and the capacity involved. The capacity allocation calendar for a multi-yearly, yearly and monthly allocations shall be proposed by the **SMO** and approved by **ERERA**.

MC 6.2 Methodology for Capacity Allocation

- MC 6.2.1 There are two (2) types of capacity allocation, the regulatory-driven allocation and the market-based allocation. The regulatory-driven allocation is performed by **ERERA** for the **Grandfathered Contracts** and the market-based allocation is performed by the **SMO** for any other contract.
- MC 6.2.2 The **Grandfathered Contracts** and the capacity allocation criteria of such contract shall be defined and **Published** by **ERERA**.
- MC 6.2.3 The capacity allocation to **Grandfather Contracts** defined by **ERERA** shall result in the **Already Allocated Capacity (AAC)** as established in the **Operation Code**.
- MC 6.2.4 The remaining capacity to be allocated via the market-based allocation is the **ATC**. The **SMO** shall develop an **Operational Procedure** referred to as “**ATC Allocation Procedure**” for allocating the capacity in the different timeframes and using the different **Allocation Mechanism (First-Come First-Serve and Explicit Auctions)**.

MC 6.2.5 The market-based capacity allocation shall be performed via the: **First-Come First-Serve** mechanism (MC 6.4) and, in the case of congestion, shall be switched permanently to the **Explicit Auction** mechanism (MC 6.6).

MC 6.2.6 Where there is no congestion in the **Cross-Border Interconnections**, the allocation will be based on the **First-come First-Served** mechanism (MC 6.4). The absence of congestion means that, in addition to the **AAC**, all the new long-term and medium-term **Bilateral Contracts** can be fully allocated in the **Cross-Border Interconnection**.

MC 6.2.7 The allocation of capacity to a Bilateral Contract by any Allocation Mechanism will result in Physical Transmission Rights (PTRs), assigned to Market Participants involved in the Bilateral Contract. These Market Participants are thus referred to as the PTR holders with capacity reservation for the specific timeframe of the allocation.

MC 6.2.8 **ERERA** can set a fee for obtaining the **PTRs** by any **Allocation Mechanism**. The fee shall be set per the whole number of **PTRs** obtained by each Market Participant with each capacity allocation process. This fee shall be paid into an infrastructure development fund of the **REM** whose terms and conditions shall be defined by **ERERA**.

MC 6.2.9 The reservation of capacity to the **PTRs** holders shall be valid for the timeframe of the respective capacity allocation and shall be subject to the **Nomination** provisions (MC 7) and the anti-hoarding measures (MC 22).

MC 6.2.10 The **PTRs** obtained may be transferred to other **Market Participants** subject to compliance with the **Market Code**.

MC 6.2.11 Except in cases of **Emergency State** or **Force Majeure Event**, the **SMO** and the relevant **System Operators** commit themselves to ensure that the **PTRs** are operationally feasible for the **Market Participant** or the holder of **PTRs**, upon reservation of capacity in the course of an auction or upon transfer of **PTRs**.

MC 6.3 Allocation of the Available Transfer Capacity (ATC)

MC 6.3.1 Due to the multi-timeframe periods for the allocation of the **ATC**, there shall be efficient and transparent criteria to split the **ATC** between the different timeframes via **Splitting Ratios** defined in the **ATC Allocation Procedure**. The **ATC Allocation Procedure** shall be proposed by the **SMO** and approved by **ERERA**.

MC 6.3.2 The **Splitting Ratios** shall take into account that it is not appropriate to allocate all the calculated **ATC** to long-term timeframes (multi-yearly and yearly), because uncertainties in the carrying capacity, due to unforeseen circumstances, increase as we move farther from the real-time operation.

MC 6.3.3 The **Splitting Ratios** shall address the hedging needs of **Market Participants**, be coherent with the capacity calculation methodology and prevent restrictions in competition, in particular for access to long-term transmission rights.

MC 6.3.4 Initially, the **Splitting Ratios** shall be an equal split between the long-term (multi-yearly and yearly) and medium term (monthly). The **Splitting Ratios** may be adjusted by the **SMO** subject to the approval of **ERERA** to reflect the **REM** developments and needs.

MC 6.4 First-Come First-Served Allocation Mechanism

MC 6.4.1 The allocation of capacity within the defined timeframes (MC 6.1) shall be undertaken for each **Cross-border Interconnection** based on the **Information** declared by the **Market Participants** about the use of the **Cross-border Interconnections** according to the quantities established in their **Bilateral Contracts**. The **ATC** calculation in accordance with the methodology established in the **Operation Code** shall be aligned with the capacity allocation timeframes in the **OTC Market**.

MC 6.4.2 The capacity allocation shall be performed on hourly basis for each timeframe defined in MC 6.1. The **SMO** shall determine whether a uniform **ATC** shall apply for every hour within the timeframe or if there is a specific profile to consider.

MC 6.4.3 For each **Cross-border Interconnection** and every timeframe defined in MC 6.1, the **First-Come First-Served Allocation Mechanism** shall apply the following steps:

- a) The **SMO** shall calculate the **NTC**, in accordance with the **Operation Code**, for the timeframe under allocation based on the **Information** provided by the **System Operators**.
- b) The **SMO** shall calculate the **AAC** in accordance with the regulatory-driven allocation established by **ERERA**.
- c) The **SMO**, in coordination with the System Operators, shall calculate the **ATC** to be allocated to the **Bilateral Contracts** for the timeframe under allocation;
- d) The **SMO** shall **Publish** the **ATC** to be allocated to the **Bilateral Contracts** for the timeframe under allocation;
- e) The **SMO** shall allocate the **ATC** to the **Bilateral Contracts** of the timeframe under allocation according to the validity of the contract;
- f) The final capacity allocated to each **Cross-border Interconnection** shall represent the hourly values in a certain flow direction established in the **Operation Code**.

MC 6.4.4 The total **ATC** may be allocated to the **OTC Market**. **ERERA** may decide to reserve a certain amount of **ATC** for the **DAM** using the **Splitting Ratio**.

MC 6.4.5 The allocated capacity to each **Bilateral Contract** establishes the **PTR** that the **Market Participants** have to **Nominate** for using the **Cross-border Interconnection** in the determined direction until the next allocation process takes place.

MC 6.4.6 The holders of the **PTR** via **First-Come First-Served** methodology shall not pay any fee for obtaining these **PTR**.

MC 6.5 Determination of Congestion

MC 6.5.1 **Congestion** for the allocation of the capacity in the **OTC Market** means that the requested reservation of the **Cross-Border Interconnection** capacity exceeds the offered capacity in a timeframe (multi-yearly, yearly or monthly). The **Congestion** may occur when requesting the registration of a new **Bilateral Contract** in the **OTC Market**.

MC 6.5.2 In case of congestion, requested capacities for **Bilateral Contracts** cannot be fully allocated.

MC 6.5.3 **ERERA** shall, following consultation with the **SMO**, determine conditions under which the **Explicit Auction** mechanism (MC 6.6) may be adopted to allocate capacity in the **OTC Market**. This adoption shall consider the level of **Congestion** in the network if there is an expected **Congestion** higher than a threshold established by **ERERA**.

MC 6.5.4 **ERERA** may adopt the **Explicit Auction** mechanism following an impact assessment which will have regard to:

- a) The level of **Congestion** in the network.
- b) The benefits and risks associated with the auction.
- c) The maturity of the market.
- d) The disbursement of revenues and potential liabilities for the **SMO**.
- e) The impact on the **OTC Market** and **DAM**.
- f) The costs and implementation timeline.
- g) The opinion of stakeholders in the **REM**.

MC 6.5.5 Upon its adoption by a decision of **ERERA**, the **Explicit Auction** mechanism shall become the exclusive means of conducting the market-based allocation in the **OTC Market**.

MC 6.6 Explicit Auction Mechanism

MC 6.6.1 Objective for Conducting Explicit Auctions

MC 6.6.1.1 The objective of the **Explicit Auctions** is to ensure the efficient, fair and transparent allocation of the ATC in the **OTC Market** where the requested reservation of the **Cross-Border Interconnection** capacity exceeds the offered capacity in a timeframe (multi-yearly, yearly or monthly).

MC 6.6.2 *Responsibilities for Conducting Explicit Auctions*

MC 6.6.2.1 The **SMO** shall be responsible for designing and conducting the **Explicit Auctions** for the allocation of capacity in the **OTC Market** for the timeframes established in MC 6.1.

MC 6.6.2.2 **ERERA** shall approve the **Explicit Auctions Allocation Procedure** based on the **SMO** recommendation. The **SMO** shall tailor the approved Procedure for each **Explicit Auction**.

MC 6.6.2.3 The **SMO** shall develop, set up and manage the **Auction Tool**, which shall be an electronic-based platform used to conduct **Explicit Auctions**. The **SMO** shall develop guidelines for using the **Auction Tool** for each timeframe established in MC 6.1.

MC 6.6.2.4 The **SMO** shall conduct the **Explicit Auctions** through the **Auction Tool** and serve as a point of contact and source of **Information** regarding the auctions to **Market Participants**.

MC 6.6.2.5 The auction proceedings may be interrupted temporarily by **SMO** at any time without prior notice in case of technical failures. Such temporary discontinuance shall not affect the rights and obligations arising from auctions that have taken place under the **Market Code** prior to such interruption.

MC 6.6.3 *Explicit Auctions Allocation*

MC 6.6.3.1 The periodic allocations under the **Explicit Auctions** shall be for capacity reservation in the long- and medium-term for the **OTC Market**.

MC 6.6.3.2 The **Explicit Auctions Allocation Procedure** (MC 6.6.2.2) and the guidelines (MC 6.6.2.3) shall be **Published** on the website of **SMO**.

MC 6.6.3.3 By accessing the **Auction Tool**, a **Market Participant** fully accepts the regulations set out in the periodic **Explicit Auctions Allocation Procedure** and the guideline **Published** on the **SMO** website, without any reservation.

MC 6.6.3.4 If the guidelines or the **Explicit Auctions Allocation Procedure** conflicts with the **Market Code**, the **Market Code** takes precedence and priority.

MC 6.6.4 *Violation of the Explicit Auctions Allocation Procedure*

MC 6.6.4.1 At all times before, during and after the conduct of an **Explicit Auction**, the **Market Participant** shall refrain from any action or behaviour which adversely affects or threatens competition in the auction proceedings such as gaming, or any other activities that disrupts or threatens to disrupt the auction proceedings, transparency, cost-effectiveness or fairness thereof.

MC 6.6.4.2 In case of actions or behaviours described in article MC 6.6.4.1, the **SMO** shall immediately report the incident to **ERERA**.

MC 6.6.4.3 Upon receipt of the report described in article MC 6.6.4.2, **ERERA** shall investigate the actions of the **Market Participant**. The **Market Participant** in violation may be excluded from further auctions as determined by **ERERA** and penalised according to anti-hoarding measures (MC 22).

MC 6.6.5 *Explicit Auction Fees*

MC 6.6.5.1 A successful bid of an **Explicit Auction** creates a contractual obligation between the **Market Participant** and the **SMO**. The **Market Participant** that obtains **PTRs** via an **Explicit Auction** shall pay to the **SMO** the **Auction Clearing Price** for the awarded **PTRs**.

MC 6.6.5.2 Where a **Market Participant** fulfils the payment conditions according to the **Explicit Auctions Allocation Procedure**, its **PTRs** are guaranteed by the **SMO** except for **Curtailment of PTR** (MC 7.2). The payment covers only the **PTRs**, and this right does not include allocation of cost for the use of the **Transmission System**. The tariff for using the **Transmission System** shall follow the **Market Code** (MC 24).

MC 6.6.6 *General Explicit Auction Process*

MC 6.6.6.1 Separate **Explicit Auctions** shall be held for the reservation of capacity in each of the two directions of the **Cross-Border Interconnection**:

- a) Auction for capacity reservation from country A to country B deals with the flow direction from country A to country B;
- b) Auction for capacity reservation from country B to country A deals with the reverse flow direction from country B to country A.

MC 6.6.6.2 The deadlines for the **Explicit Auctions** shall be Published by the **SMO** with reasonable anticipation and in accordance with the **Explicit Auctions Allocation Procedure** and guidelines for **Auction Tool**.

MC 6.6.6.3 The **Auction Bids** for allocation in the respective directions shall be submitted using the **Auction Tool** according to the guidelines for **Auction tool**. Only the **Auction Bids** delivered in the accepted format and in time will be considered by the **Auction Tool**. **Market Participants** shall submit their **Auction Bids** through the **Auction Tool** on the **SMO** website.

MC 6.6.6.4 Each **Market Participant** shall submit their **Auction Bids** within the timeframe established in the **Explicit Auctions Allocation Procedure**. The **Auction Bids** delivered to the **SMO** shall be binding for the relevant **Explicit Auction** and cannot be withdrawn or modified after the deadline.

MC 6.6.6.5 Each **Auction Bid** performed shall contain the following unambiguous and legible specifications:

- a) The specification of the relevant flow direction.

- b) The **Auction Bid** value shall be in USD/MW in each hour with two (2) decimal places. The **Auction Bid** price must be greater than zero and shall be equal in each hour.
- c) The amount of the capacity requested to be reserved, in MW, without decimal places
- d) The minimum amount of a single **Auction Bid** is 1MW or multiple of it, and the maximum amount of a single **Auction Bid** is the minimum value of:
 - i. The 100% value of the **ATC** calculated by **SMO**.
 - ii. The maximum value of its **Bilateral Contract**.
- e) The **Market Participant** shall not request more than the Published **ATC** per auction.
- f) The hourly requested capacity.

MC 6.6.6.6 The **Auction Bids** which fail to meet the requirement in MC 6.6.6.5 shall be deemed non-compliant and excluded from the auction.

MC 6.6.6.7 The offered price of each **Auction Bid** represents the highest price the **Market Participant** is willing to pay.

MC 6.6.6.8 Multiple **Auction Bids** may be submitted by a **Market Participant** for each **Explicit Auction**. Such **Auction Bids** submitted are valid and independent of each other. The maximum **Auction Bids** and the conditions of submission of Multiple **Auction Bids** shall be set out in the **Explicit Auctions Allocation Procedure** to be developed by the **SMO** and approved by **ERERA**.

MC 6.6.6.9 In case the **Explicit Auction** cannot be performed due to the failure of the **Auction Tool**, the **SMO** shall reschedule the auction and Publish the rescheduled deadline.

MC 6.6.6.10 Where necessary, **ERERA** may decide to apply a maximum limit to the **Explicit Auction** bidding prices.

MC 6.6.7 **Explicit Auction Clearing Price**

MC 6.6.7.1 The results of each **Explicit Auction** shall be determined for the relevant **Cross-border Interconnections** for each hour as follows:

- a) The acceptable **Auction Bids** for Capacity are ranked in descending order based on bid prices, and the **Auction Bids** shall be summed in that order.
- b) Where the above sum is equal to or less than the **ATC** of the **Cross-border Interconnection** offered for the **Explicit Auction** at a given Interconnection, the **Auction Clearing Price** shall be deemed to be zero. This outcome is equivalent to the First-Come-First-Served allocation mechanism.
- c) Where the cumulative capacity of all **Auction Bids** exceeds the **ATC**, the **Auction Bid(s)** offering the highest price for a cumulative capacity that does not exceed the **ATC** shall be fully accepted. The remaining portion of the **ATC** shall be allocated to the next highest-priced **Auction Bid** or multiple **Auction Bids** with equal prices, provide that their cumulative capacity exhaust the **ATC** without exceeding it.

MC 6.6.7.2 Where two or more **Auction Bids** have been submitted at the same price and the remaining **Available Transfer Capacity (ATC)** is insufficient to fully satisfy all such **Bids**, the remaining capacity shall be allocated proportionally among the equally priced **Auction Bids**, in whole units of one (1) megawatt (MW), in accordance with the principles set out in the **Explicit Auction Allocation Procedure**.

MC 6.6.7.3 The **SMO** has the right to consider the time of submission of the offers as a priority for awarding the **PTRs**, in case the proportional principle mentioned in MC 6.6.7.2 is inapplicable.

MC 6.6.7.4 The **Auction Clearing Price** is the price of the last MW allocated due to insufficient auctioned capacity, which is the marginal price on the congested **Cross-border Interconnection**. The **Auction Clearing Price** shall be paid by all **Market Participants** that have been awarded capacity in the **Explicit Auction** on the **Cross-border Interconnection**.

MC 6.6.8 **Notification of Auction Results**

MC 6.6.8.1 The **SMO** will provide each **Market Participant** that participated in the explicit auction with the following data, in the **Auction Tool**, at the deadline for publication of the **Explicit Auction** results:

- a) Specification of the relevant auction
- b) Period of reservation
- c) **PTRs** for the **Market Participant** in MW for each hour
- d) **Auction Clearing Price** as determined for every MW for each hour of the **Explicit Auction** period

MC 6.6.8.2 The **SMO** shall Publish on its website the results of the periodic **Explicit Auction** in accordance with the deadline established in the **Explicit Auctions Allocation Procedure**. The results shall include the following:

- a) Total amount of awarded **PTRs**, in MW per hour
- b) **Auction Clearing Price**
- c) Number of bidders
- d) Total requested capacity
- e) The names of the successful bidders and the quantity of awarded **PTR** to each of them
- f) The total capacity awarded
- g) Non-allocated capacity, if any.

MC 6.6.9 **Invoicing, Payment and Loss of PTRs**

MC 6.6.9.1 The **SMO** shall be responsible for handling the invoicing, collection and accounting for revenues from the **PTR** allocations.

- MC 6.6.9.2 **ERERA** shall adopt a regulation governing the use of the revenue from the **PTR** allocations.
- MC 6.6.9.3 Payment from **Explicit Auctions** shall be settled in advance and before using **PTRs**. The **PTR** holder shall pay the **PTRs** value, following a receipt of the respective invoice issued by **SMO**. The payments for the **Auction Clearing Price** for each MW of every hour may be performed in monthly instalment(s) according to the extent of the timeframe of the **Explicit Auction**.
- MC 6.6.9.4 The **SMO** issues a monthly invoice payable prior to the month the **PTRs** will be used. The invoice will cover the monthly capacity allocated to the **Market Participant**, considering the hourly allocations in the given month, representing the amount of **PTRs** allocated.
- MC 6.6.9.5 The deadline for issuing invoices (date of performance) shall be no later than the twentieth (20th) **Day** of the month preceding the month of use of the **PTR**.
- MC 6.6.9.6 The **Market Participant** shall pay the invoice amount into the **SMO**'s designated account and submit the proof of payment to the **SMO** by e-mail no later than the invoice maturity date.
- MC 6.6.9.7 All bank charges related to the payment shall be borne by the **Market Participant**. The date of payment shall be the date upon which the given amount is credited to the designated account of the **SMO**. Invoices shall be paid in full no later than the maturity date stated on the invoice and without deduction and/or offsetting.
- MC 6.6.9.8 Where the maturity date of the invoice falls on a public holiday, payment shall be received at the latest on the preceding working day. Should the maturity date fall on a Sunday or a public holiday immediately following a Sunday, payment shall be received at the latest on the following working day.
- MC 6.6.9.9 In case of late payment, the **SMO** shall be entitled to charge default rates on a due amount for each **Day** of delay. The default interest rate shall be determined by **ERERA**.
- MC 6.6.9.10 In case the payment is not settled by the maturity date indicated on the invoice and the amount due exceeds the value of the **Collateral** provided, the **SMO** shall be entitled to withdraw from the obligations resulting from the **Explicit Auctions Allocation Procedure**. Consequently, the **Market Participant** loses his **PTRs** obtained in an auction and shall be liable pursuant to the general provisions of the **Explicit Auctions Allocation Procedure**.
- MC 6.6.9.11 In case the payment is not settled by the maturity date indicated in the invoice and the amount due is less than the value of the **Collateral**, the **SMO** is entitled to enforce the **Collateral** to recover the amount due. The **Market Participant** does not lose the **PTRs** obtained in an auction but must submit a new **Collateral**.

MC 6.7 Fallback Procedure for Explicit Auctions

MC 6.7.1 General provisions

MC 6.7.1.1 The **SMO** shall, to the extent reasonably practicable, develop and implement an **Operational Procedure** named “**OTC Fallback Procedure**” in the following cases of failure of the standard process:

- a) if it is not possible to hold an **Explicit Auction** in the following cases:
 - i. it is technically not possible to use the standard data exchange with the **SMO**;
 - ii. the **SMO** faces technical obstacles during the **Explicit Auction** process;
- b) in the event of erroneous results due to incorrect **Auction Clearing Price** calculation;
- c) in the event of incorrect allocation of the **PTR to Market Participants**.

MC 6.7.1.2 In the **OTC Fallback Procedure**, the **SMO** may consider using one or all of the following fallback measures:

- a) introduction of a fallback measure for data exchange according to MC 6.7.2;
- b) postponement of start of the **Explicit Auction** to a later time as defined by the **SMO**;
- c) introduction of a **Fallback Auction** according to MC 6.7.4;
- d) any other fallback measure which the **SMO** considers appropriate to overcome the technical obstacles.

MC 6.7.1.3 Where necessary, the **SMO**, without undue delay, shall inform **Market Participants** by email and on its website, the use of the **OTC Fallback Procedure**.

MC 6.7.1.4 **Market Participants** shall immediately inform the **SMO** of any observed problems using the **Auction Tool** and any potential consequences via the available contact channels indicated on the website of the **SMO** in written form.

MC 6.7.2 **OTC Fallback Measures for data exchange**

MC 6.7.2.1 In case of failure of the standard processes for data exchange with the **SMO**, the **OTC Fallback Procedure** applicable for data exchange shall be as follows:

- a) In conformity with the **Explicit Auctions Allocation Procedure**, the **Market Participant** shall request, via telephone and e-mail, the **SMO** to enter the relevant data into the **Auction Tool**;
- b) The **Market Participant** shall provide its request to the **SMO** in the format specified in the **Explicit Auctions Allocation Procedures** the relevant data to be entered in the **Auction Tool**;
- c) the **SMO** shall enter the submitted data into the **Auction Tool**;
- d) the **SMO** shall set in the **Explicit Auctions Allocation Procedures** an identification mechanism of **Market Participants** for the application of the **OTC Fallback Procedure**. If the **Market Participant** does not clearly identify itself, the **SMO** shall not perform the data entry;

- e) the **Market Participant** shall provide the **SMO** with a telephone number, which can be used in case of a necessary communication;
- f) once the **SMO** has entered the provided data into the **Auction Tool** on behalf of the **Market Participant**, the **SMO** shall inform, without undue delay, the **Market Participant** by telephone and via e-mail of the entry; and
- g) the **SMO** shall under no circumstances be held responsible if it is unable to reach the **Market Participant** through the means of communication above.

MC 6.7.2.2 In case of application of the **OTC Fallback Procedure** for data exchange, all necessary non-**Confidential Information** made available via the **Auction Tool** during the standard processes may be distributed to the **Market Participants** via e-mail by the **SMO** or, where appropriate, Published on the website of the **SMO**.

MC 6.7.3 *Fallback Measures for Explicit Auctions*

MC 6.7.3.1 The postponement of the **Explicit Auction** shall be the default fallback measure for **Explicit Auctions** before the bidding period has opened. The **SMO** may postpone an **Explicit Auction** by notifying **Market Participants** of the revised time of the new **Explicit Auction**.

MC 6.7.3.2 After the bidding period has opened, the **SMO** shall:

- a) where reasonably practicable postpone the end of the bidding period by notifying **Market Participants** about the revised deadlines;
- b) cancel the initial **Explicit Auction** according to MC 6.7.5, and organize a new **Explicit Auction**;
- c) apply **Fallback Auction** as specified in MC 6.7.4.

MC 6.7.3.3 The **SMO** shall inform all **Market Participants**, without undue delay, of the postponement by notification via email and publication in the **Auction Tool** and on the webpage of the **SMO**.

MC 6.7.4 *Fallback Auction*

MC 6.7.4.1 If the **SMO**, after Publishing the **Explicit Auction** specification, is unable to hold auction processes due to reasons listed in article MC 6.7.1.1, the **SMO** shall send the notification to all **Market Participants** of the application of **Fallback Auction** as soon as possible at the date and time defined by the **SMO**.

MC 6.7.5 *Explicit Auction cancellation*

MC 6.7.5.1 If the **SMO** cancels an **Explicit Auction**, all **Auction Bids** already submitted and any results of the **Explicit Auction** shall be deemed null and void.

MC 6.7.5.2 The **SMO** shall inform all **Market Participants**, without undue delay, of the auction cancellation by notification via email and publication in the **Auction Tool** and on the webpage of the **SMO**.

MC 6.7.5.3 An **Explicit Auction** cancellation may occur in the following cases:

- a) before the provisional auction results publication in case the **SMO** faces technical obstacles during the auction process like a failure of standard processes and fallback measures; and
- b) after the provisional auction results publication, in the event of erroneous results due to incorrect **Auction Clearing Price** calculation or incorrect allocation of **PTR** to **Market Participants** and failure of fallback measure.

MC 6.7.5.4 In case of auction cancellation before the final auction results publication, no compensation shall be paid to the **Market Participants**. MC 6.7.5

MC 6.7.5.5 The **SMO** shall Publish on its website, without undue delay, the reasons for the **Explicit Auction** cancellation.

MC 6.8 Provision of Collaterals for Explicit Auctions

MC 6.8.1 As a prerequisite for participation in the **Explicit Auctions**, the **Market Participant** shall commit to providing the required **Collateral**.

MC 6.8.2 Each **Collateral** submitted to the **SMO** shall be subject to the national law of the country of residence of the **SMO** and should be issued by a solvent credit institution, legally operating in a **Member State**. This credit institution shall not be a **Market Participant** itself or shall not be connected to the **Market Participant** in terms of ownership or under the meaning of corporate law.

MC 6.8.3 The standard form of the **Collateral** shall be developed by the **SMO** and approved by **ERERA**.

MC 6.8.4 The **Market Participant** shall ensure that the acceptance value of the **Collaterals** registered by the credit institution continuously meets the actual requirements of the **Explicit Auctions Allocation Procedure**.

MC 6.8.5 The **Market Participants** shall submit to the **SMO**, at least two (2) working days before the **Explicit Auction**, a bank guarantee regarding participation in the auction. The **SMO** may set a minimum rate.

MC 6.8.6 Prior to publication of the final auction result, the **Market Participant** who obtained the **PTRs** from the **Explicit Auction** shall adjust the amount of the bank guarantee provided in MC 6.8.5 within five (5) working days from the date of the provisional allocation of the **PTRs** to the **Market Participant**, to cover at least (i) One month for the monthly **PTR** allocation and (ii) two months for yearly or multi-yearly **PTR** allocation. In case the **Market Participant** does not increase the amount of the **Collateral** within the deadlines, the **Market Participants** shall forfeit the allocated

PTR and be excluded from the auction result. The **SMO** shall update the auction result without the excluded **Market Participants**.

MC 6.8.7 Upon receipt of all **Collaterals** of **Market Participants** who have obtained their **PTRs**, the **SMO** shall **Publish** the final auction result.

MC 6.8.8 In case the advance payment for the allocated **PTR** is not executed on the due date according to the invoice, the **Collateral** is forfeited to the due payment amount. Furthermore, the **PTR** holder will be charged by **SMO** with any additional expenses arising out of the demand for payment made under **Collateral**.

MC 7. NOMINATION OF CAPACITY BY THE PHYSICAL TRANSMISSION RIGHTS (PTR) HOLDERS

MC 7.1 Nomination of Capacity

MC 7.1.1 The holders of the **PTRs** shall **Nominate** the capacity values obtained through the **Allocation Mechanism**.

MC 7.1.2 The **Nomination** shall be conducted the preceding Day of dispatching. In the event the holder of a **PTR** does not or partially nominate its **PTR**, the non-nominated capacity will be available for the **Day-Ahead Market**.

MC 7.1.3 The **Nomination** of capacity should be equal to or less than the **PTRs** obtained through the **Allocation Mechanism**.

MC 7.1.4 The **Nomination** of capacity in the **OTC Market** shall be performed daily at a time established by the **SMO**. The **SMO** shall coordinate the gate closure of the **Nominations** with the **System Operators** of the **Member States** to facilitate the scheduling and dispatching in the **Member States** and the **Regional Electricity Market**. The **SMO** shall develop an **Operational Procedure** named "Capacity Nomination Procedure" for the nomination process, including formats, variables, parameters, and other **Information** required.

MC 7.1.5 The **Nomination** of capacity shall be done by submitting to the **SMO** a fixed and binding schedule for each hour of the following Day. The **Nominations** must be received by the **Gate Closure Time (GCT)** established by the **SMO** in coordination with the involved **System Operators**.

MC 7.1.6 In the event of a mismatch between nominated schedules at **GCT**, the involved **Market Participants** will send corrections of the already submitted **Nominations** to the **SMO** and their respective **System Operators** before the **Final Gate Closure Time (FGCT)**.

MC 7.1.7 If there is a mismatch after the **Final Gate Closure Time (FGCT)**, the **SMO** shall modify the schedules derived from the **Nominations** according to the following rules:

- a) Where the **Nomination** values differ, the lower value shall be taken into account.
- b) Where there is no counterpart for a **Nomination** or the directions are incorrect, zero values are taken into account.
- c) Where the **Nomination** values are above the allocated **PTR**, the allocated **PTR** shall be used.

MC 7.1.8 Modifications of schedules by **PTR** holders after **FGCT** are not possible. Use of the **PTR** shall be based on the principle of "**Use It or Lose It**" (**UIOLI**). This means that the unused part of the **PTRs** shall be forfeited and reallocated to the **Day-Ahead Market**. The **PTR** holders who did not nominate their **PTRs** are not entitled to any remuneration.

MC 7.2 Curtailment of the PTR

MC 7.2.1 *General Provisions*

- MC 7.2.1.1 **Curtailment** of **PTRs** shall only be used in **Emergency State** or **Force Majeure Event** when an involved **System Operator** must act expeditiously, and redispatching is not possible. The **SMO** shall develop an **Operational Procedure** named “**PTR Curtailment Procedure**” to be applied in a non-discriminatory manner.
- MC 7.2.1.2 A **System Operator** who requests the **Curtailment** of **PTR** shall submit to the **SMO** a description of the reasons and impacts of the **Curtailment** on its **Network** and the expected problems in its **Power System**. This **Information** shall be Published by the **SMO** on its website.
- MC 7.2.1.3 **PTRs Curtailment** and/or reduction of submitted **Nominations** shall have as reference a time-period multiple of one hour. **PTRs Curtailment** and/or reduction of submitted **Nominations** shall be done in a non-discriminatory manner, meaning that yearly and monthly **PTRs** shall be curtailed/reduced in the same way as **Day-ahead market PTRs**.
- MC 7.2.1.4 In case of **Curtailment** of **PTRs**, the **Market Participant(s)** whose **PTRs** have been curtailed shall be reimbursed by the **SMO** for the curtailed **PTRs** proportional to the amount spent to obtain the **PTR**.

MC 7.2.2 *Curtailment before the FGCT*

- MC 7.2.2.1 Before the **FGCT**, the **PTRs** shall be curtailed by the **SMO** based on a formal request from involved **System Operators** according to the “**PTR Curtailment Procedure**”.
- MC 7.2.2.2 The non-firm capacities shall be curtailed first. Thereafter, firm capacities shall be curtailed on a pro-rata basis by applying to each **PTR**, the ratio between the available capacity after the **Curtailment** triggering event and the sum of total allocated **PTRs**.
- MC 7.2.2.3 The **SMO** shall notify the affected **Market Participants** of the curtailed non-firm and firm capacities. The **Market Participants** shall submit the **Nominations** to the **SMO** and the involved **System Operators**, taking into account the curtailed capacity.

MC 7.2.3 *Curtailment of Nomination after the FGCT*

- MC 7.2.3.1 After the **FGCT**, the **Curtailment** of **Nominations** shall be carried out by the involved **System Operators** in coordination with **SMO**.
- MC 7.2.3.2 The non-firm capacities shall be curtailed first. Thereafter, if necessary, the firm capacities shall be curtailed on a pro-rata basis by applying the ratio between the amount of available capacity after the **Curtailment** triggering event and the sum of all **PTRs**, as follows:
- a) To each allocated **PTR**, if the Curtailment occurs before the publication of the **Day-Ahead Market** clearing. Submitted **Nominations** shall be adjusted accordingly.

- b) To nominated **PTRs** and the **Implicit Allocations** from the **Day-Ahead Market**, if the **Curtailement** occurs after the publication of the **Day-Ahead Market** clearing.

MC 7.3 Transfer of the PTR

MC 7.3.1 **PTRs** awarded by any market-based **Allocation Mechanism** can be transferred under the following conditions:

- a) It is allowed to transfer allocated **PTRs** only to other **Market Participants** registered in the **OTC Platform**.
- b) The quantity of transferable **PTRs** shall be one (1) MW or integer multiple of one (1) MW. The transferable quantity shall not exceed the allocated **PTRs**.
- c) The transfer of a **PTR** shall be done no later than five (5) **Days** before using the transferred **PTR** by **Nomination**.
- d) Where the **PTRs** were obtained through **Explicit Auctions**, the **PTR** holder must have paid to the **SMO** the **PTRs** over the period he wants to transfer.

MC 7.3.2 The **SMO** shall develop an **Operational Procedure** named “**PTR** Transfer and Return Procedure” with the conditions and guidelines for transfer of the **PTRs** obtained by any market-based **Allocation Mechanism**.

MC 7.3.3 The transfer shall be performed electronically by the **Market Participants** through the **OTC Platform**. Also, the **Market Participant** shall submit the transfer form included in the “**PTR** Transfer and Return Procedure” for each transfer of **OTC Market** allocated capacities, to the **SMO**, by a pre-established e-mail address.

MC 7.3.4 The **SMO** cannot be held responsible for an interrupted provision of the **OTC Platform**.

MC 7.3.5 All detailed instructions concerning the requirements for accessing the **OTC Platform** for the transfer process shall be included in the “**PTR** Transfer and Return Procedure”.

MC 7.3.6 By accessing the **OTC Platform**, the **Market Participant** shall be obliged to accept the regulations set out in the **Explicit Auctions Allocation Procedure** and the “**PTRs** Transfer and Return Procedure” without any reservation.

MC 7.3.7 The transfer becomes effective after confirmation by both the old and the new holder of transferred **PTRs**. After confirmation of the transfer, only the new **PTRs** holder shall be entitled to use the transferred **PTRs**. In case the transfer does not comply with the **Explicit Auctions Allocation Procedure** and the “**PTRs** Transfer and Return Procedure” or the **Market Participant** announces to transfer more **PTRs** than he has obtained in an auction, the whole transfer shall not

be valid. Any **Disputes** arising from disagreements between the old and the new holder of the **PTRs** shall not affect the validity of the transfer after it becomes effective.

MC 7.3.8 After the transfer, all obligations resulting from holding the **PTR** are transferred to the new holder of the **PTR**.

MC 7.3.9 The new holder of the transferred **PTRs** shall be subject to the principle of “**Use It or Lose It**” (**UIOLI**).

MC 7.4 Return of the PTR

MC 7.4.1 A holder of **PTR**, obtained through market-based **Allocation Mechanism**, may return its **PTR** to the **SMO** through the **OTC Platform** for subsequent forward capacity allocation.

MC 7.4.2 A **PTR** holder who returns its **PTRs** shall be remunerated by the **SMO** through the **OTC Platform** after reallocation to a third party within the period of validity of the **PTR**. Such remuneration shall be equal to the price resulting from the auction where its **PTR** is reallocated.

MC 8. SCHEDULING OF TRANSACTIONS IN THE OTC MARKET

- MC 8.1.1 The **Market Participants** shall submit daily, the **Information** required for their **Nominations** (MC 7) for the day-ahead scheduling in the **OTC Market**.
- MC 8.1.2 In order to schedule the transactions in the **OTC Market**, at least the following minimum **Information** shall be submitted by the **Market Participants** involved in each **Bilateral Contract**:
- a) The **Parties** involved in the **Bilateral Contract**.
 - b) The **PTR** obtained by any **Allocation Mechanism**, the holder of the **PTR**, its validity and duration.
 - c) Their hourly **Nominations**.
 - d) Other **Information** as required by the **SMO** to complete their scheduling process.
- MC 8.1.3 The long- and medium-term **PTRs**, referred to as firm capacity, have precedence over the short-term **PTRs**, referred to as non-firm capacity.
- MC 8.1.4 The scheduling of the transactions in the **OTC Market** will be performed by the **SMO**. The OTC market scheduling results and the **DAM** results shall be communicated to the involved **System Operators** at the agreed time. This is to facilitate the individual countries' power system scheduling and dispatching process by the involved **System Operators**.
- MC 8.1.5 The schedules should be in a format pre-defined by the **SMO** and should contain the hourly schedules of the **Market Participants** and use of each **Cross-border Interconnection** and the direction of the flow.
- MC 8.1.6 The **SMO** shall compare corresponding values of the exchange of energy related to a given **Bilateral Contract** without applying corrective measures. A matched verification result shall have the same values for a given direction and for all time intervals in each hour.
- MC 8.1.7 In case of a mismatched verification result, the involved **Market Participants** have the obligation to resolve the mismatch.
- MC 8.1.8 The aggregation of all scheduled energy on **Cross-border Interconnections** shall sum up to zero.
- MC 8.1.9 The schedules shall be Published on the **SMO** website and sent to the involved **System Operators** by pre-defined communication means.
- MC 8.1.10 Based on the schedules Published and delivered by the **SMO**, the involved **System Operators** shall perform the dispatching on the **Delivery Day** in their national **Power Systems**.

MC 9. OTHER PROVISIONS ON THE OTC MARKET

MC 9.1 Waiver of Right to Compensate and Limitation of Liability

MC 9.1.1 The **Market Participant** shall not offset and/or withhold any debts arising in connection with an auction to any claim against **SMO**, whether or not such debt arises out of or relates to an auction.

MC 9.1.2 Claims for damages arising out of or related to the **ATC Allocation Procedure**, **Explicit Auctions Allocation Procedure** and/or the capacity allocation to contract shall be limited to the damages typical and foreseeable unless the **SMO** has acted wilfully or by gross negligence. In no event shall the **SMO** be liable for any loss of profit, loss of business, or any other indirect incidental, special or consequential damages of any kind. In any case, the liability of the **SMO** for damages arising out of or related to the **ATC Allocation Procedure** and **Explicit Auctions Allocation Procedure** shall be limited for each **Market Participant** to an amount, expressed in USD per year, to be determined by **ERERA**.

MC 9.1.3 The **SMO** undertakes to carry out the provisions set out in the **Explicit Auctions Allocation Procedure** in accordance with **Good Utility Practice**.

MC 9.1.4 The **SMO** shall not be excluded from any liability due to a breach caused either wilfully, or by gross negligence, or by a felony, or by an offence

MC 9.2 Complaint relating to the ATC Allocation Procedure

MC 9.2.1 Where the **Market Participant** concludes that the **ATC Allocation Procedure** has been breached by an incorrect calculation, incorrect output from data check, or incorrect evaluation, the **Market Participant** is entitled to initiate a complaint process.

MC 9.2.2 The complaint shall be submitted to **SMO**, by e-mail or via registered mail, within two (2) working days from receiving the invoice or other relevant document, and must contain:

- a) date of submission;
- b) identification of **Market Participant**;
- c) name, e-mail address and telephone of a responsible contact person;
- d) subject matter;
- e) detailed description of the situation ;
- f) supporting evidence including downloads from logs, communication records, etc.

MC 9.2.3 **SMO** shall confirm the receipt of such a complaint via e-mail.

- MC 9.2.4 Where the **SMO** and **Market Participant** are unable to resolve the complaint within thirty (30) working days from the date of submission, the **Market Participant** may initiate a **Dispute** resolution with **ERERA** in accordance with MC 26.
- MC 9.2.5 The involved **System Operators** and the **SMO** shall provide relevant **Information** to **ERERA** for its proceeding.
- MC 9.2.6 The complaint shall not have a suspensive effect on the results of the relevant auction.

TITLE III – DAY-AHEAD MARKET

MC 10. DAY-AHEAD MARKET (DAM) PRINCIPLES

MC 10.1 Characteristics of the Regional DAM

MC 10.1.1 The DAM shall have the following main characteristics:

- a) It shall be organised by the **SMO**.
- b) Participation shall be voluntary for **Market Participants**.
- c) It shall operate as a short-term market with daily trading.
- d) It shall be a double-sided market, i.e., **Buyers** and **Sellers** perform their **Orders**.
- e) The electricity traded in the **DAM** shall be for physical delivery.
- f) The product allowed to trade in the **DAM** shall be solely energy.

MC 10.1.2 Trades in the **Day-Ahead Market** shall be conducted electronically and anonymously. Trades shall be conducted through an **Energy Trading System (ETS)**.

MC 10.1.3 When trading in the **Day-Ahead Market**, the **SMO** shall keep confidential the identity of the **Market Participants**. Trading shall be carried out anonymously, when placing and registering **Offers** and **Bids** on the **ETS**.

MC 10.2 Capacity Offered to the Day-Ahead Market

MC 10.2.1 The **Physical Transmission Right (PTR)** offered to the **Day-Ahead Market** shall be the **ATC** minus the capacity allocated in the **OTC Market**.

MC 10.2.2 The capacity offered in the **DAM** shall be deemed as non-firm capacity.

MC 10.2.3 Prior to the **DAM Gate Opening Time**, the **SMO** shall communicate to the **Market Participants** the offered capacity on the **DAM**. This offered capacity shall be equal to the sum of the **ATC** not allocated in the several timeframes of **OTC Market** plus the non-nominated **PTR** by the **Bilateral Contracts** (MC 7).

MC 10.2.4 **ANNEX E** provides an illustration of the indicative **DAM** timeline based on the provisions of the **Market Code** for the **DAM**.

MC 10.3 General Provisions

MC 10.3.1 Introduction

MC 10.3.1.1 The **Day-Ahead Market** is designed for energy trading (buying and selling) with an obligation of physical delivery. A **Market Participant** shall submit its **Offers** and/or **Bids** at each **Day D-1** for the physical delivery for each **Market Time Unit** in **Day D**.

MC 10.3.1.2 The **SMO** shall develop an **Operational Procedure** named "**DAM Procedure**", which shall define the basic requirements for participating, the timeline of the **DAM**, the **Market Time Units**, the reference time for the operation and transactions, the areas in the **REM** for trading in the **DAM** and other details required for effective participation and trading in the **DAM**.

MC 10.3.2 *Trading hours*

MC 10.3.2.1 **Day-Ahead Market** operates every **Day (D-1)** for physical delivery of energy the following **Day (D)**.

MC 10.3.2.2 In the **DAM**, buy orders shall be referred to as **Bids** and sell orders shall be referred to as **Offers**.

MC 10.3.2.3 **Offers** and **Bids** for delivery on **Day D** are submitted by **Market Participants** in the **ETS** for the **Day-Ahead Market** from the **DAM Gate Opening Time** until the **DAM Gate Closure Time**. The **ETS** shall validate the **Offers** and **Bids** after the **DAM Gate Closure Time**.

MC 10.3.2.4 **SMO** may extend the **DAM Gate Closure Time** to the extent required to maintain orderly trading conditions. The **DAM Gate Closure Time** may be extended for reasons related to the availability of the **ETS**. In such case, **SMO** shall inform the **Market Participants** concerning the reasons for the extension and the associated actions required from **SMO** and **Market Participants**. In the eventual extension of the **DAM Gate Closure Time**, the **SMO** shall act with neutrality, and its conduct shall be subject to monitoring and surveillance by **ERERA**.

MC 10.3.2.5 The definition of the exact timelines, including the **Gate Opening Time**, the **Gate Closure Time** and the duration of the validation process shall be included by the **SMO** in coordination with the **System Operators** in the "**DAM Procedure**".

MC 10.3.3 *Day-Ahead Market Products*

MC 10.3.3.1 The product admitted for trading on the **Day-Ahead Market** is the energy with physical delivery (injection or withdrawal) within the **WAPPITS**

MC 10.3.3.2 Initially, the **Market Time Unit** of the **Day-Ahead Market** shall be one (1) hour and the **Delivery Day** shall comprise twenty-four (24) **Market Time Units**.

MC 10.3.3.3 The **Market Time Unit** may be changed by the **SMO** subject to the amendment of the "**DAM Procedure**" and the approval of **ERERA**.

The reference time for the operation and transactions in the **REM** shall be the Coordinated Universal Time (UTC +1 time zone).

MC 10.3.4 *Day-Ahead Market Price Limits*

MC 10.3.4.1 **ERERA** may decide to apply limits on maximum and minimum clearing prices for the **Day-Ahead Market**. These limits shall become the permitted range of the **DAM** clearing price

MC 10.3.4.2 In the event the permitted range is applied to the **Day-Ahead Market** clearing prices, the following shall be adopted:

- a) **ERERA** shall set a minimum **Order** price (**Offer** and **Bids**) for the **Day-Ahead Market** to avoid anti-competitive practices. Initially, the minimum **Order** price shall be set at 0.00 USD/MWh and may be changed, adjusted and updated by **ERERA**.
- b) **ERERA** shall set a maximum **Order** price (**Offers** and **Bids**) for the **Day-Ahead Market** to limit and minimise the use of market power and anti-competitive practices (MC 21.7.1a). Initially, the maximum **Order** price shall be set at 50 % of the cost of **Expected Energy Not Served as** determined by **ERERA** for the **WAPP Power System**. This initial value may be changed, adjusted and updated by **ERERA**.

MC 10.3.5 ***Day-Ahead Market Price by Area***

MC 10.3.5.1 There may be as many **DAM** prices cleared as areas in the **REM**.

MC 10.3.5.2 The **Market Participants** may perform their **Offers** and **Bids** simultaneously for the different areas of the **REM**.

MC 10.3.5.3 The **SMO** shall clear and determine **DAM** prices for every area of the **REM**.

MC 11. DAY-AHEAD MARKET PARTICIPANTS

MC 11.1 Conditions for Participation in the DAM

MC 11.1.1 To participate in the **DAM**, an **Entity** must be authorised and registered as a **Market Participant** by **ERERA**.

MC 11.1.2 The **Market Participant** shall sign the “Day-Ahead Market Participation Agreement” for participating in the **Day-Ahead Market** as established in **ANNEX C**.

MC 11.1.3 Upon receipt of the acceptance notice from **ERERA** and execution of the “Day-Ahead Market Participation Agreement” with the **SMO**, the **Market Participant** shall have the right to trade in the **DAM** according to the **REMR**.

MC 11.1.4 The **Market Participant** registered in the **DAM** shall be entitled to access **Information** made available by **ERERA** and **SMO** for **Market Participants**.

MC 11.2 Responsibilities of the Market Participants in the DAM

MC 11.2.1 Each **Market Participant** in the **DAM** shall be responsible for submission and receipt of data in the interchange process with the **SMO**, specifically such as:

- a) Hourly **Offers** by **Sellers**, which include a pair of variables quantity and its selling price. The quantity offered shall be an integer multiple of one (1) MW, and the hourly unitary price shall be in USD/MWh with a maximum of two (2) decimal places.
- b) Hourly **Bids** by **Buyers** which include a pair of variables quantity and its price willing to pay. The quantity bid shall be an integer multiple of one (1) MW, and the hourly unitary price the **Buyer** is willing to pay shall be in USD/MWh with a maximum of two (2) decimal places.
- c) Any commercial **Information** and other relevant data as may be reasonably required by the **SMO**.

MC 11.3 Participation in the I DAM

MC 11.3.1 **Market Participant** may designate one or more **Certified Traders** (MC 13.2) to act on its behalf in the **Day-Ahead Market**.

MC 12. ENERGY TRADING SYSTEM (ETS)

MC 12.1 Provision of the ETS

MC 12.1.1 For **Market Participants'** access to the **ETS**, the **SMO** shall provide **Market Participants** with the appropriate and reliable applications, and shall develop the technical specifications for the required systems.

MC 12.1.2 The **SMO** shall provide each **Market Participant** in the **DAM** with a unique identification code to trade in **ETS**.

MC 12.1.3 The **SMO** may allow **Market Participants** to use third-party software provided that it is compatible with **SMO** technical specifications and can be integrated with the **ETS**.

MC 12.1.4 Concerning the use of the connection services to **ETS** provided by the **SMO**, the **Market Participant** has the following obligations:

- a) To obtain the necessary technological and other equipment at its own expense and to ensure adequate **Facilities** for its installation, based on the technical specifications provided by the **SMO**.
- b) To provide an **Information** Technology (IT) expert responsible for the communication with the **SMO** and the follow-up of issues related to the **Market Participant's** connection to the **ETS**.
- c) To ensure that, at the time specified by the **SMO**, the designated IT expert will be available on call to help the **Market Participant**.
- d) To take appropriate measures to prevent or detect prohibited activities according to the technical specifications of the **SMO**.
- e) To maintain the technical equipment and software provided by the **SMO** in good condition, not interfering with it without the prior permission of the **SMO** and to respect the **SMO's** rights to them.

MC 12.1.5 The **SMO** is entitled to discontinue the **Market Participant's** access to the **ETS** in the following circumstances:

- a) occurrence of a technical malfunction of the **ETS**,
- b) the **Market Participant** does not comply with the technical specifications and instructions of the **SMO**,
- c) the **SMO** detects unauthorised use of the **Market Participant's** connection,
- d) any other circumstance necessary for imposing measures.

MC 12.1.6 The **SMO** shall maintain the records of **Market Participant's** access to the **ETS** for a period of five (5) years.

MC 12.2 ETS Authorised users

MC 12.2.1 The use of **ETS** to submit **Orders** in the **DAM** is permitted only to **Certified Traders** authorised by **Market Participants**.

MC 12.2.2 **Market Participants** shall submit to the **SMO Information** on their authorised users and any subsequent change to such **Information**.

MC 12.3 User control

MC 12.3.1 **Market Participants** are obliged to establish special internal audit procedures for monitoring the activities performed by users of the **ETS**.

MC 12.3.2 The **SMO** may, at its discretion, prohibit user access to the **ETS** if there are cases of imposition of sanctions under the provisions of MC 23.

MC 12.4 User passwords

MC 12.4.1 The **ETS** allows access only to authorised users of the **Market Participants**.

MC 12.4.2 To gain access, each user must receive from the **SMO** a special password that is unique per user.

MC 12.4.3 The **Offer** and **Bid** submitted to the **SMO** by **Market Participants** on the **ETS** for trading are binding for the **Market Participants**. The **Market Participant** shall be liable for the use of its passwords by unauthorised persons.

MC 12.4.4 **Market Participants** shall immediately notify the **SMO** of any change involving users or any revocation of the capacity of the user for any reason whatsoever so that the **SMO** can permanently or temporarily deactivate that user's password.

MC 12.5 Market Participants Technological Infrastructure

MC 12.5.1 Technological services related to applications and IT systems offered by the **SMO** to **Market Participants** include support in the software installation, management and operation services, as well as providing technical assistance and support to users.

MC 12.5.2 Authorised users of such technological services shall include **Market Participants** and any other **Entity** that has been granted the right to use the specialised services provided by the **SMO**, like the **NRA** and **ERERA**.

MC 12.5.3 The technological services include the selection, installation and configuration of the technical means (equipment, software, network interfaces, etc.) available or specified by the **SMO** and required for the efficient, reliable and secure access of users to the technological services of the **SMO**.

MC 13. TRADING IN THE DAM ON THE ETS

MC 13.1 Orders: Offers and Bids

MC 13.1.1 *Participation in the Day-Ahead Market*

MC 13.1.1.1 Participation in the **Day-Ahead Market** shall be optional for all **Market Participants**.

MC 13.1.2 *Type of Orders*

MC 13.1.2.1 The types of **Orders** for the **Day-Ahead Market** shall be submitted by the **Market Participants** as follows:

- a) **Hourly Orders:** Hourly **Offers** and **Bids** consist of an hourly quantity and its price.
- b) **Block Orders:** A **Block Order** consists of a fixed price limit (minimum price for selling a **Block Order** and maximum price for buying a **Block Order**), a **Minimum Acceptance Ratio** and an energy quantity for a number of consecutive **Market Time Units** within the **Delivery Day**. The energy quantity may vary in different **Market Time Units**. **Block Orders** cannot be accepted for a volume less than their **Minimum Acceptance Ratio**. The **Minimum Acceptance Ratio** shall be the same for all **Market Time Units** belonging to the **Block Order**.
- c) **Linked Block Orders:** A **Linked Block Order** consists of individual **Block Orders**, with the attributes referred to in the **Block Order**, which are linked to each other by a parent-child relationship. A child **Block Order** can only be accepted when the parent **Block Order** with which it is linked is executed. **Block Orders** without linked child **Block Orders** are called leaf **Block Orders**.
- d) **Exclusive Group of Block Orders:** An **Exclusive Group** consists of a set of **Block Orders** for which the sum of the accepted ratios cannot exceed the unit (1). In the specific case where the individual **Block Orders** have a **Minimum Acceptance Ratio** of one (1), then at most, one of the **Block Orders** can be accepted.

MC 13.1.2.2 The SMO shall accept the **Hourly Orders**, **Block Orders**, and **Linked Block Orders** for trading on the **ETS**.

MC 13.1.2.3 The admission of new types of **Orders** and the suspension/deletion of the existing type of **Orders** shall be subject to the proposal of the **SMO** and approval by **ERERA**.

MC 13.1.3 *Content of Orders*

MC 13.1.3.1 The minimum content of an **Order** submitted by a **Market Participant** on the **ETS** shall be as follows:

- a) **Market Participant** unique identification code assigned by the **SMO** to trade on the **ETS**;

- b) **Order** type (**Hourly Order**, **Block Order**, etc.);
- c) **Offer** or **Bid**;
- d) Energy quantity and price for each **Hourly Order** or each **Block Order**;
- e) **Market Time Unit**(s) for which it is submitted;
- f) Location of **Generation** or consumption; and
- g) Any additional **Information**, where required, as defined by the **ETS** functionality requirements.

MC 13.1.3.2 **Order** prices shall be submitted in USD/MWh with two (2) decimal places. **Order** quantities are submitted in MW per hour with no decimal places.

MC 13.1.4 *Validation of Offers and Bids*

MC 13.1.4.1 The **ETS** shall automatically reject an **Order** submitted by a **Market Participant**, based on the time of receipt by the **SMO**, specifically when it has been received before the **DAM Gate Opening Time** or after the **DAM Gate Closure Time**.

MC 13.1.4.2 The **ETS** shall automatically reject an **Order** submitted by a **Market Participant**, based on the **Order** price, and when the **Order** price is outside the range defined by **ERERA** as specified in MC 10.3.4. In case of automatic rejection of an **Order**, the **ETS** shall automatically send a rejection notice to the respective **Market Participant**, including a justification for such denial.

MC 13.1.4.3 The **ETS** shall automatically reject any submitted **Offer /Bid** by a **Market Participant** when the value of the **Offer /Bid** is higher than the respective **Trading Limit** set for the **Market Participant** by the **Clearing House**.

MC 13.1.4.4 The **ETS** shall automatically reject any submitted **Offer /Bid** by a **Market Participant** when the **Order** violates the restrictions on specific types of **Orders** or submission parameters specified by the **SMO**.

MC 13.1.4.5 The **ETS** shall automatically reject each submitted **Order** by a **Market Participant** concerning the **Order** quantity as follows:

- a) When the **Offer** quantity corresponding to energy injection for exports is higher than the respective **ATC**, computed according to the **Operation Code**;
- b) When the **Bid** quantity corresponding to energy offtake for imports is higher than the respective **ATC** computed according to the **Operation Code**.

MC 13.2 **Certified Traders**

MC 13.2.1 A **Certified Trader** is a person duly designated by a **Market Participant** to perform trading on its behalf in the **Regional Electricity Market**.

MC 13.2.2 To ensure the professional competence of the **Market Participants'** employees and agents, **SMO** shall issue an energy trading certificate relating to its eligibility to perform the duties of a **Certified Trader** in the **Regional Electricity Market**.

MC 13.2.3 Neither the **Market Participant** nor its **Certified Trader** shall grant access to the **ETS** to any person that has not been designated and registered by the **SMO** as a **Certified Trader**.

MC 13.2.4 **Market Participant** may request the **SMO**, in writing, to terminate the access of a **Certified Trader** and/or grant access to a new **Certified Trader**. The **SMO** shall confirm in writing such termination and/or grant of access to a new **Certified Trader** to the **Market Participant**.

MC 13.2.5 In case a **Certified Trader** fails to comply with the provisions of the **Market Code** or acts in a manner detrimental or threatening to the interests of the **SMO** and/or the **REM**, the **SMO** may immediately suspend or terminate the access of the **Certified Trader** without prior notice. In such case, the **SMO** shall immediately inform, in writing, the **Market Participant** and, where applicable, request the **Market Participant** to designate a new **Certified Trader**.

MC 13.2.6 **The Market Participant** shall be responsible for the security and the use of the access of its **Certified Trader(s)**. The **Market Participant** shall be liable for all damages arising out of any unauthorised use of its access.

MC 13.2.7 Upon the proposal of the **SMO**, **ERERA** may take any of the following measures against a **Market Participant** that fails to comply with one or more of its market obligations:

- a) Order the cessation of the non-compliance with the market obligations.
- b) Impose any of the following disciplinary measures:
 - i. Issue a warning;
 - ii. Suspend the **Market Participant** for a maximum period of one (1) month; and/or
 - iii. Terminate the **Market Participant's** participation in all or part of the markets in the REM.

MC 13.2.8 In case of urgency and/or if the proper functioning of the market is jeopardised, the **SMO** may immediately, without any third-party intervention suspend any **Market Participant** from trading.

MC 13.2.9 The **SMO** shall notify the **Market Participant** and **ERERA** of such suspension using the fastest means of communication.

MC 13.3 Trading on Behalf Service

MC 13.3.1 **Market Participants** shall ensure their connection equipment to the **ETS** is in good working condition and have in place backup connection systems to ensure continuous participation in the **Day-Ahead Market**. **Market Participants** shall also ensure the availability of their **Certified Traders** when conducting their trades.

MC 13.3.2 In the event of an incident not due to a technical malfunction of the **ETS**, such as a malfunction in the **Market Participant's** internal network, the **SMO** shall provide, at the request of the **Market Participant**, a trading support process named **Trading on Behalf** service.

MC 13.3.3 At the request of the **Market Participant**, the **SMO** shall:

- a) receive and submit on the **ETS** the **Offers** and **Bids** of the **Market Participant**;
- b) amend or annul registered **Offers** and **Bids** of the **Market Participant**; and
- c) in general, proceed to any action of participation in the **DAM**, based on the provisions of the **Market Code**.

MC 13.3.4 A **Market Participant** intending to use the **Trading on Behalf** service shall submit an electronic request to the **SMO** at the latest fifteen (15) minutes before the **Gate Closure Time**. The **Trading on Behalf** request shall be submitted together with the electronic request of the submission of **Offers** and **Bids** in a format defined by **SMO**.

MC 13.3.5 The **SMO** shall charge a fee for the use of the **Trading on Behalf** service subject to the prior approval by **ERERA**.

MC 13.3.6 The **SMO** shall develop an **Operational Procedure** named “Trading on Behalf Procedure” to establish the conditions required for this service.

MC 13.4 Fallback Procedure for DAM Trading

MC 13.4.1 General provisions

MC 13.4.1.1 The **SMO** shall, to the extent reasonably practicable, organize and design an **Operational Procedure** named “**DAM Fallback Procedure**” in the following cases of failure of the **ETS** platform:

- a) where it is technically impossible to hold trading in the following cases:
 - i. where it is technically impossible to use the standard data exchange with the **SMO**; or
 - ii. in case the **SMO** encounters technical constraints during the trading process with **ETS**; or

- b) in the event of erroneous results due to incorrect **DAM** clearing price calculation; or
- c) in the event of incorrect explicit capacity allocation of the **PTR** to **Market Participants** or similar reasons.

MC 13.4.1.2 The **SMO** may use one or all of the following fallback measures:

- a) introduction of a fallback measure for data exchange according to MC 13.4.2
- b) postponement of the **Gate Opening Time** to a later time as defined by the **SMO**, but no later than a time that could jeopardize the **Member States'** scheduling process;
- c) introduction of a **Fallback Day-Ahead Trading** according to MC 13.4.3;
- d) any other ad hoc fallback measures deemed appropriate by the **SMO** to overcome the technical constraints.

MC 13.4.1.3 The **SMO** shall, to the extent practicable and without undue delay, inform **Market Participants** of possible deviations from the standard processes and the application of the “**DAM Fallback Procedure**” via e-mail and the **SMO's** website and the **ETS**, if possible.

MC 13.4.1.4 **Market Participants** shall immediately notify the **SMO** of any observed problems using the **ETS** and all potential consequences via the available contact channels indicated on the website of the **SMO** in written form. In case of an urgent problem, which shall be solved immediately and which is identified during working hours, the **Market Participant** shall immediately contact the **SMO** by phone at the telephone number indicated on the website of the **SMO** for this type of problem. The **SMO** shall confirm the receipt of the problem and inform **Market Participants** of the problem status as soon as possible.

MC 13.4.2 *Fallback Measures for data exchange*

MC 13.4.2.1 In case of a failure at the site of the **SMO** of the standard processes for data exchange with the **SMO**, the **SMO** may inform **Market Participants** that fallback measures for data exchange for the **DAM** trading may be used as follows:

- a) By the applicable deadlines, unless otherwise announced by the **SMO**, the **Market Participant** shall request via e-mail the **SMO** to enter the relevant data into the **ETS** by using the “**DAM Fallback Procedure**” for data exchange;
- b) with the request, the **Market Participant** shall provide the relevant data to be entered into the **ETS** in the format specified by the **SMO**;
- c) the **SMO** shall enter the submitted data into the **ETS**;
- d) the **SMO** shall set in the “**DAM Fallback Procedure**” an identification mechanism of **Market Participants** when submitting the request to the **SMO** to enter data into the **ETS** on their behalf. If the **Market Participant** does not clearly identify itself, the **SMO** shall not perform the data entry;
- e) The **Market Participant** shall provide the **SMO** with a telephone number and an e-mail address, which can be used in case of necessary communication;

- f) Once the **SMO** has entered the provided data into the **ETS** on behalf of the **Market Participant**, the **SMO** shall inform, without undue delay, the **Market Participant** by telephone and/or via e-mail of the entry; and
- g) The **SMO** shall under no circumstances be held responsible if it fails to reach the **Market Participant** through the means of communication above.

MC 13.4.2.2 In case of application of the "**DAM Fallback Procedure**" for data exchange, all necessary non-confidential **Information** made available via the **ETS** during the standard processes may be distributed to the **Market Participants** via e-mail by the **SMO** or, where appropriate, Published on the **SMO** website.

MC 13.4.3 *Fallback Measures for DAM Trading*

MC 13.4.3.1 The postponement of the **DAM** trade shall be the default fallback measure before the bidding period has opened. The **SMO** may postpone the trade by notifying **Market Participants** of the revised time to the new **Gate Opening Time**.

MC 13.4.3.2 After the trading period has opened, the **SMO** shall, where reasonably practicable, postpone the end of the trading period and change the **Gate Closure Time** by notifying **Market Participants** about the revised deadlines.

MC 13.4.3.3 The **SMO** shall inform all **Market Participants**, without undue delay, of the postponement by Publishing a notification on the **ETS** and on the **SMO's** webpage and by e-mail.

MC 13.5 **Offers and Bids**

MC 13.5.1 The energy quantities included in **Offers** of the **Sellers** and corresponding to injection are submitted at the **Injection Point(s)**.

MC 13.5.2 The energy quantities included in **Bids** of the **Buyers** and corresponding to a withdrawal are submitted at the **Withdrawal Point(s)**.

MC 13.5.3 The **Sellers** and **Buyers** shall be responsible for the energy losses arising from the **Injection Point(s)** to the **Withdrawal Point(s)**. The loss factor applied to their energy quantities shall be determined and approved by its relevant **NRA** and **ERERA**.

MC 13.5.4 **Metering Equipment** shall be installed and maintained at each **Injection Point**, **Withdrawal Point** and **Defined Metering Point** of the **Cross-border Interconnection** to measure the transactions. The procurement, ownership, installation and maintenance of the **Metering Equipment** shall be the responsibility of the relevant **Transmission Operator**, as established in the **Metering Code**.

MC 14. PRUDENTIAL RESPONSIBILITIES

MC 14.1 Prudential Guidelines and Procedure

MC 14.1.1 Clearing and Settlement of the trades on the **Day-Ahead Market** shall be conducted by a **Clearing House**.

MC 14.1.2 Initially, the **SMO** is the nominated **Clearing House** for the **Day-Ahead Market**. To this effect, the **SMO** shall designate a financial institution to discharge the financial function of the **Clearing House**. According to the market evolution and conditions, a **Clearing House** could be outsourced, subject to **ERERA's** approval.

MC 14.1.3 The **SMO** shall develop an **Operational Procedure** named “Prudential Procedure and Guidelines” to determine the prudential requirements for the participation of the **Market Participants** in the **Day-Ahead Market**.

MC 14.1.4 The “Prudential Procedure and Guidelines shall contain the methodology to calculate the **Credit Limits, Credit Support, Trading Limit, Prudential Margin, Trading Margin**, and each **Market Participant's** expected outstanding amount.

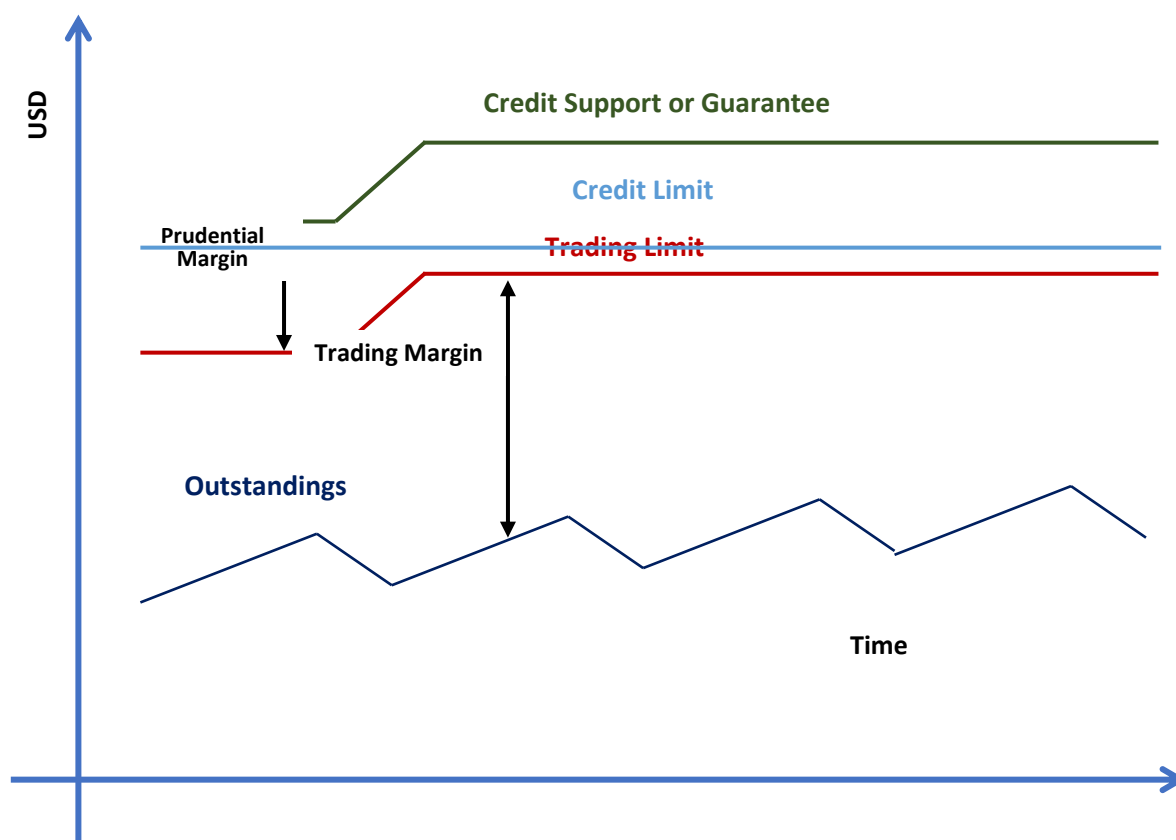


Figure MC 1. Prudential Framework for participating in the **Day-Ahead Market**

MC 14.1.5 The “Prudential Procedure and Guidelines” shall additionally include **Credit Support** arrangements, including:

- a) The form of acceptable guarantees and letters of credit;
- b) The location and conditions for holding cash deposits, along with how the associated costs and fees will be covered;
- c) The selection of the Settlement bank;
- d) The list of factors to be taken into account for assessing the expected value of transactions;
- e) The Issuance of **Margin Calls**; and
- f) Other matters.

MC 14.1.6 The “Prudential Procedure and Guidelines” may consider the **Reallocations** in order to reduce the **Credit Support**.

MC 14.1.7 **Market Participants** and the **Clearing House** must comply with the “Prudential Procedure and Guidelines” at all times.

MC 14.2 Prudential Requirements for Market Participation - Credit Limits

MC 14.2.1 The **Clearing House** must determine a **Credit Limit** for each **Market Participant**. The **Credit Limits** shall be reviewed periodically and at least every quarter.

MC 14.2.2 **Credit Limit** for a **Market Participant** is the amount in US dollars (USD) determined by the **Clearing House** as being equal to the amount that the **SMO** reasonably expects will not be exceeded over any 45-Day period. The **Credit Limit** shall be:

- a) the maximum net amount reasonably expected to be payable by the **Market Participant** to the **Clearing House** over a 45-Day period;
- b) determined by applying the factors set out in MC 14.2.3; and
- c) calculated according to the approved “Prudential Procedure and Guidelines”

MC 14.2.3 When determining a **Market Participant's Credit Limit**, the **Clearing House** must consider the following:

- a) The **Market Participant's** historical level of payments based on metered quantity data for the **Market Participant**, or an estimate of the **Market Participant's** future level of payments based on its expected **Generation** and/or consumption quantities where no metered quantity data is available;
- b) The **Market Participant's** historical level of Settlement payments, or an estimate of the **Market Participant's** future level of Settlement payments based on its expected sales and purchases where no historical Settlement payment data is available;
- c) The length of the Settlement cycle;

- d) The historical volatility factor; and
- e) Any other factor that the **Clearing House** considers relevant.

MC 14.2.4 In determining a **Market Participant's Credit Limit**, the **Clearing House** may, to the extent it considers relevant, take into account a minimum amount that the **Clearing House** considers would adequately protect the **Regional Electricity Market** if a **Suspension** event were to occur concerning that **Market Participant**.

MC 14.2.5 The **Clearing House** must notify each **Market Participant** of its determined **Credit Limit**, including any revisions of the **Credit Limits**. The **SMO** must provide details of the basis for the determination of the **Credit Limit**. The **Clearing House** may establish a monitoring mechanism for automatic notification to the **Market Participant** to replenish the **Credit Limit**.

MC 14.2.6 Every **Market Participant** shall inform the **Clearing House** as soon as practicable of any circumstance that may result in an increase in its **Credit Limit**.

MC 14.3 Prudential Requirements for Market Participation - Credit Support

MC 14.3.1 A **Market Participant** shall ensure that, at all times, the **Clearing House** holds the benefit of a **Credit Support** that is appropriate in terms of security and in an amount not less than the most recently determined **Credit Limit** for that **Market Participant**.

MC 14.3.2 Where a **Market Participant's** existing **Credit Support** is due to expire or cease to have effect for any other reason, that **Market Participant** must ensure that the **Clearing House** holds the benefit of a new **Credit Support**.

MC 14.3.3 The Credit Support for a Market Participant shall be:

- a) an obligation in writing from a **Credit Support** provider, who must be an **Entity** that meets the acceptable credit criteria and which itself is not a **Market Participant**;
- b) a guarantee or bank undertaking in the form of an irrevocable standby letter of credit consistent with the Rules on International Standby Practices (ISP98) and the amount as determined by the **Clearing House**;
- c) duly executed by the **Credit Support** provider and delivered unconditionally to the **Clearing House**;
- d) a valid and binding unsubordinated obligation to the **Credit Support** provider to pay to the **Clearing House** amounts in accordance with its terms, which relate to the relevant **Market Participant's** obligations; and
- e) an obligation in writing that permits drawings or claims by the **Clearing House** up to a stated amount.

MC 14.3.4 The **Credit Support** for a **Market Participant** may be constituted by a cash deposit or cash equivalents ("**Security Deposit**") made to the **Clearing House** by or on behalf of the **Market Participant**.

MC 14.3.5 Where **Credit Support** is provided in the form of a **Security Deposit**, it will accrue interest daily at the Settlement bank rate, and the **Clearing House** must forward the **Market Participant** the interest accumulated at the end of each calendar month less any liabilities and expenses incurred by the **Clearing House**, including bank fees and charges.

MC 14.4 Prudential Requirements for Market Participation - Trading Limit and Prudential Margin

MC 14.4.1 The Trading Limit for a Market Participant shall be determined by its Credit Support held less a Prudential Margin.

MC 14.4.2 A **Prudential Margin** is a seven (7) Day financial buffer period determined by the **Clearing House** based on the transactions of the **Market Participant**. The purpose of the **Prudential Margin** is to ensure that the **Clearing House** is not exposed to a prudential risk during the period of **Suspension** of a defaulting **Market Participant** from the **REM**, the reaction period being seven Days.

MC 14.4.3 The final **Trading Limit** for a **Market Participant** shall be its **Credit Limit**, or its **Credit Support** held less the **Prudential Margin**, whichever of the two is lower.

MC 14.4.4 The **Outstanding Amount** for a **Market Participant** at any time equals the total amount calculated as follows:

$$\text{Outstanding Amount} = (a) - (b)$$

Where:

(a) is the aggregate of the amounts payable by the **Market Participant** to the **Clearing House**, including amounts for all past periods for which no Settlement statement has yet been issued and whether or not the payment date has yet been reached;

(b) is the aggregate of the amounts payable by the **Clearing House** to the **Market Participant**, including amounts for all past periods for which no Settlement statement has yet been issued and whether or not the payment date has yet been reached.

MC 14.5 Prudential Requirements for Market Participation - Trading Margin

MC 14.5.1 **Trading Margin** for a **Market Participant** at any time equals the amount by which its **Trading Limit** exceeds its **Outstanding Amount** at that time.

MC 14.5.2 The **SMO** shall implement a **Prudential Dashboard** in the **ETS** to provide each **Market Participant** in the **Day-Ahead Market** with the latest prudential **Information**, including the **Trading Margin**. The **Prudential Dashboard** shall (i) be updated regularly as new prudential **Information** becomes available, (ii) report on how the **Market Participant** is prudentially behaving and (iii) provide readily accessible data needed for prudential management decisions.

MC 14.5.3 A **Market Participant** must not make any submission to the **Clearing House** where the transaction contemplated by the submission could result in the **Market Participant's Trading Margin** being exceeded.

MC 14.5.4 The **SMO** may reject any submission from a **Market Participant**, resulting in the **Market Participant's Trading Margin** being exceeded.

MC 14.6 Margin Call

MC 14.6.1 Where a **Market Participant's Trading Margin** is less than zero, the **Clearing House** shall issue a **Margin Call** notice to the **Market Participant**, specifying the of the **Margin Call** amount.

MC 14.6.2 The **Margin Call** amount must be the amount required to increase the **Market Participant's Trading Margin** to at least a zero.

MC 14.6.3 A **Market Participant** must respond to a **Margin Call** notice within forty-eight (48) hours of the notice by:

- a) paying to the **Clearing House** in cleared funds an appropriate **Security Deposit**; or
- b) ensuring the **Clearing House** has the benefit of additional **Credit Support** corresponding to the **Margin Call** amount.

MC 14.6.4 Where a **Market Participant** fails to respond to a **Margin Call** appropriately, the **SMO** may cancel its Bids and any market submissions.

MC 15. CLEARING IN THE DAY-AHEAD MARKET

MC 15.1 Clearing and Settlement

MC 15.1.1 **Clearing** of the energy deliveries resulting from the trades, including the Settlement, shall be performed by the **Clearing House** according to the **Market Code**.

MC 15.1.2 The **Clearing House** shall perform the clearing based on the trading records of the **ETS**.

MC 15.1.3 The **SMO** shall design and develop an **Operational Procedure** named “Settlement Procedure” for performing the Settlement.

MC 15.1.4 The Settlement shall be performed by the **SMO** with the data collected from the involved **System Operators**. In the event of incorrect transfer or changes to the contents of the records, the **System Operators** shall correct the relevant data according to the prescribed technical procedures by informing the **SMO** on a case-by-case basis.

MC 15.1.5 In case of rescheduling due to intentional deviations, the rescheduled energy quantities shall be settled based on the **DAM** clearing price.

MC 15.2 Clearing in the DAM – General Provisions

MC 15.2.1 The objective of the **DAM** pricing is to enhance Security of Supply in the short-term and maximise the overall exchanges across the **Region** per each **Market Time Unit** and for the target trading Day.

MC 15.2.2 The **SMO** shall develop an **Operational Procedure** named “**DAM** Clearing Procedure” that governs the participation of the **Clearing House** and the **Market Participants** in the **DAM**. This **DAM** Clearing Procedure sets out the terms and conditions under which transactions are cleared through the **ETS**.

MC 15.2.3 The process of **Clearing** shall be carried out through the **ETS** individually for all transactions registered on the **ETS** on the Day of trading within the scheduled business hours as decided by the **Clearing House**.

MC 15.2.4 **Clearing** involves the following processes:

- a) Finalisation of trades;
- b) Clearance of the **Day-Ahead Market** price;
- c) Calculation, at a specific time of the Day, of obligations and claims;
- d) Calculation and recovery of **Trading Margin**;

- e) Calculation and monitoring of **Credit Limits** and notification of the **Credit Limits** per **Market Participant**;
- f) **Publication** of **Clearing** results;

MC 15.3 Day-Ahead Market Price

MC 15.3.1 The **Clearing House** shall perform the **Clearing** of the **Day-Ahead Market** through the **ETS** system. The **Information** considered shall be:

- a) The market-**Clearing** price per **Market Time Unit**;
- b) The accepted energy quantity of the **Offers** of each **Market Participant** in each **Market Time Unit**, and
- c) The accepted energy quantity of the **Bids** of each **Market Participant** in each **Market Time Unit**.

MC 15.3.2 The **Clearing House, through** the **ETS**, shall calculate the credits and debits of the **Market Participants** resulting from their participation and trading in the **DAM**.

MC 15.3.3 The **Clearing House** shall notify the **Market Participants** of the **DAM** results on the **ETS** and Publish the aggregate **DAM** results on the **SMO's** website.

MC 15.3.4 The **Clearing** consists of matching the **Offers** and **Bids** for each **Market Time Unit** of the traded energy. The price determined by matching the **Offers** and **Bids** will be the **Day-Ahead Market Price**. The target is to maximise the Regional social welfare, therefore **Bids** are ranked per decreasing price (from the highest to the lowest price) and **Offers** are ranked per increasing price (from the lowest to the highest price). This creates two curves (an increasing one, the **Offers** curve, and a decreasing one, the **Bids** curve), and the equilibrium point (that is where the two curves meet) between these two curves is the **Day-Ahead Market** clearing price for the specific interconnected area and **Market Time Unit**.

MC 15.3.5 If the determined **DAM** price exceeds the maximum **Order** price (MC 10.3.4.2 b) or is lower than the minimum **Order** price (MC 10.3.4.2 a) approved by **ERERA** for one or more **Market Time Units**, the **Clearing House** shall cap the **DAM** price and notify the **SMO**.

MC 15.3.6 The **Clearing** process shall determine the approved transactions for the Day ahead, considering the **DAM** clearing price for **Sellers** and **Buyers**.

MC 15.4 Data for Clearing, and Calculation and Netting of Positions

MC 15.4.1 During the course of the Day of trading, the data from the **ETS** shall be checked. The detailed data on must include the following:

- a) **Market Participant** code;

- b) Code of the **Entity** for which the transaction was concluded;
- c) Type of **Order** (hourly order, block order, etc.);
- d) **Offer** or **Bid**;
- e) Quantity and price of energy;
- f) Date and time of trade;
- g) **Market Time Unit**(s) to which the transactions relate.

MC 15.4.2 The **Clearing House** shall verify the data and remedy any omissions and inconsistencies for **Clearing** purposes to form the total **Positions** per **Market Participant**.

MC 15.4.3 Upon the finalisation of trades, the **Clearing House** shall calculate the **Market Participants' Positions** (obligations/claims).

MC 15.4.4 To calculate the **Positions** per **Market Participant**, the **Clearing House** at a specific time on each business Day, shall calculate for each **Market Participant** the net obligations and net claims arising based on the transactions determined after the **DAM Clearing** process.

MC 15.5 Prudential Calculations

MC 15.5.1 The Clearing House shall determine the required Trading Margin and Credit Limit.

MC 15.5.2 To meet the **Trading Margin** and **Credit Limit** requirements, the **Clearing House** shall calculate the total value of **Collateral** provided by a **Market Participant**, taking into consideration the amount of cash deposited as well as the monetary value and period of validity of the letters of credit deposited.

MC 16. CAPACITY ALLOCATION IN THE DAY-AHEAD MARKET

- MC 16.1.1 The capacity allocation in the **Day-Ahead Market** shall be performed through **Implicit Allocation**.
- MC 16.1.2 The capacity allocation for the **Day-Ahead Market** shall be conducted simultaneously with the **Clearing** process in the **Day-Ahead Market**. The **Implicit Allocation** mechanism allocates capacity based on the price of energy **Offers/Bids** entered into the **ETS**.
- MC 16.1.3 In the **Implicit Allocations**, the energy allocated and the capacity of the **Cross-border Interconnection(s)** are based on the **Offers** and/or **Bids** placed for the **Day-Ahead Market**.
- MC 16.1.4 **Market Participants** selected for trading in the **Day-Ahead Market** shall have automatically reserved capacity in the **Cross-border Interconnection(s)** according to their **Offers** and **Bids** in the flow direction of the **Order**. The capacity and the **PTRs** for using the interconnection(s) are reserved for them.
- MC 16.1.5 The **SMO** shall each **Day Publish** the capacity allocated by the **Implicit Allocation** on an hourly basis and per flow direction.

TITLE IV – SETTLEMENT AND IMBALANCES

MC 17. SETTLEMENT IN REGIONAL ELECTRICITY MARKET

MC 17.1 General Provisions on Settlement

MC 17.1.1.1 The operation of the **WAPPITS** requires creating suitable conditions for commercial electricity trade. Therefore, it is necessary to schedule in advance the power to be exchanged at the interconnection borders between the system operators, according to the result of the **REM**. During daily real-time operations, the schedules are followed through the **Load-Frequency Control** installed in each **Load-Frequency Control Area**. Notwithstanding **Load-Frequency Control**, **Imbalances** invariably occur in energy exchanges. In addition, **Imbalances** can occur as unintentional deviations relating to supply and Demand fluctuations possibly due to network constraints or **Generation** forced outages. For this reason, it is necessary to observe in real-time **Imbalances** and coordinate the proper calculation by the **Compensation Programs** to balance **Imbalances**. The scheduling and dispatching activities are captured in OC-7.

MC 17.1.1.2 In this **Market Code** all imbalances are aggregated and treated the same.

MC 17.1.1.3 The **Settlement** in the **OTC Market** and in the **Day-Ahead Market** shall be performed by the **SMO** based on the collected data from the **Defined Metering Points**.

MC 17.2 Data Collection

MC 17.2.1 *Responsibilities of the SMO regarding the Metering Systems*

MC 17.2.1.1 The **SMO** shall remotely collect the readings from the **Metering Equipment** of each **Cross-border Interconnection** through secure communication channels utilizing specific usernames and passwords in accordance with IEC 62056. The access, user details, date, time, and duration of connections shall be automatically registered by the meters and/or the **Metering Equipment**.

MC 17.2.1.2 The **SMO** shall be responsible for developing, for approval by **ERERA**, the **Validation, Estimation and Editing (VEE)** rules for the remotely acquired readings from the **Metering Equipment**.

MC 17.2.1.3 The **SMO** shall apply the approved **VEE** rules (MC 17.3) to the remotely acquired readings and determine the **Validated Quantities** of electricity utilized by the **Imbalance** calculation.

MC 17.2.1.4 Any communication issue with a **Metering Equipment** shall be immediately communicated via the approved and formal communication channels to the **Transmission Operator** or **Entity** responsible for that **Metering Equipment**.

MC 17.2.2 *Collection of Meter Data*

MC 17.2.2.1 Data from each **Defined Metering Point** shall be downloaded daily for the twenty-four (24) hours of the **Delivery Day**. The data from the **Injection Points** and the **Withdrawal Points** involved in the transactions must be obtained by the **SMO** either by remotely accessing those meters (if the **Market Participant** allows) or from the **Grid Operators**.

MC 17.2.2.2 In the event of a failure to acquire data, a further attempt shall be made during the following Day. If that fails, the **Transmission Operator** or another responsible **Party** shall be requested to attend to the physical metering installation to manually read the meter and send this **Information** to the **SMO**.

MC 17.2.2.3 The meter readings to be used in Settlement and balancing calculations shall be those of the **Defined Metering Points** of each **Cross-border Interconnection** and where applicable the metering points of the **Injection Points** and **Withdrawal Points** involved in the transactions.

MC 17.2.2.4 Where there is a discrepancy between readings at each end of a **Cross-border Interconnection** that cannot be reasonably explained by transmission losses, or where one of the **Parties** disputes the readings, the **SMO** shall perform the **VEE** (MC 17.3) with the data from backup meters at each node.

MC 17.2.3 *Communication Problems with the Metering Equipment*

MC 17.2.3.1 Where there is a communication problem with any meter, the **SMO**, and the involved **Transmission Operator**, being the owner of the **Meter**, shall observe the following steps:

- a) the **SMO** shall immediately communicate to the **Transmission Operator**, owner of the **Meter** or other responsible **Party** for the concerned **Defined Metering Point**.
- b) The responsible **Transmission Operator** or **Party** shall, within the next one (1) hour, acknowledge the identified communication problem and communicate the remedial actions to be performed.
- c) Unless physical damage was identified in the installed **Metering Equipment** and/or remote communication system, the problem should be resolved within the next twenty-four (24) hours from the time the **SMO** communicates the problem to the responsible **Transmission Operator** or **Party**.
- d) The **SMO** shall Publish the problem in the **Metering Equipment** and may postpone the issuance of a daily Settlement according to the status of the actions being performed by the responsible **Transmission Operator** or responsible **Party**.

MC 17.2.3.2 Where a defect is detected at any **Defined Metering Point**, the **Metering Equipment** shall be re-calibrated. Any faults identified shall be repaired by the **Transmission Operator** as soon as possible.

MC 17.3 **Validation, Estimation and Editing (VEE)**

MC 17.3.1 The **SMO** shall be responsible for developing an **Operational Procedure** named "Validation, Estimation and Editing Rules" containing the **VEE** rules.

MC 17.3.2 The "Validation, Estimation and Editing Rules" shall define rules for validating the electronic readings collected from the meters of the **Metering Equipment**. The "Validation,

Estimation and Editing Rules” shall also define the different types of errors that could possibly be detected during the validation process.

MC 17.3.3 The Standard 4405 of UN/EDIFACT can be considered a starting point for classifying the errors during the **VEE** process. Some additional types of errors may be introduced to fulfil the validation process requirements.

MC 17.3.4 The validation rules to be applied to the collected readings shall be automatic without human intervention and shall consider at least the following:

- a) The reading from a meter is lower than expected
- b) The time series readings are incomplete
- c) Missing readings
- d) Missing time stamps
- e) Additional readings
- f) Timestamps are shifted more than seven (7) seconds
- g) Reactive Power is higher than active power
- h) Power outage
- i) Negative values

MC 17.3.5 Where the **Main Meter** does not comply with the validation rules, the values provided by the **Check Meter** shall be used. Where the **Check Meter** readings cannot be used after applying the automatic validation rules, the automated estimation rules should be applied. The estimation will be used in the following cases:

- a) Missing reading from the **Metering Point** in both the **Main Meter** and **Check Meter**;
- b) Missing reading of all the values in both the **Main Meter** and **Check Meter**;
- c) Missing values are more than or equal to two (2) consecutive readings according to the **Market Time Unit** defined;
- d) Missing values are more than or equal to ten (10) readings according to the **Market Time Unit** defined;
- e) Any other case identified and proposed by the **SMO**.

MC 17.3.6 After the automatic estimation is performed, a validation of the estimation is required with the same validation rules.

MC 17.3.7 Editing is a manual modification process of the readings that cannot be estimated by the automatic rules proposed by the **SMO**. This is the last step performed by the **SMO** and the edited fields shall be flagged for the correct identification.

MC 17.3.8 The general principle to be followed when editing is that the total amount of energy (read + estimated + edited) for the **Delivery Day** must follow the seasonal, weekly and daily variations.

MC 17.3.9 The results of the **VEE** process will deliver the **Validated Quantities** of electricity for **Settlement** and **Imbalances** calculation purposes.

MC 17.4 Daily Settlement Statement

MC 17.4.1 Every **Day**, the **SMO** shall prepare a **Daily Settlement Statement** by reporting the following **Information**:

- a) The **Day** of the year to which the **Daily Settlement Statement** relates;
- b) The type of **Settlement** statement;
- c) The daily **Validated Quantities** of each **System Operator** on the **Day** to which the **Daily Settlement Statement** relates;
- d) The **System Operator Imbalances** of the **Day** to which the **Daily Settlement Statement** relates (MC 18).

MC 17.4.2 The **SMO** shall Publish the **Daily Settlement Statement** on the **ETS** no later than 12:00Hrs (noon) on the Day following the **Settlement Day** to which the evaluation of the **Imbalances** relates.

MC 17.5 Rectified Daily Settlement Statements

MC 17.5.1 Where the **SMO** identifies one or more quantities to be amended in the **Daily Settlement Statement** (MC 17.4), the **SMO** shall rectify and rePublish the **Daily Settlement Statement** on the **ETS**.

MC 17.5.2 If a **System Operator** identifies that a rectification to the Published **Daily Settlement Statement** is required, it shall submit the following:

- a) The identification and **Code** of the **System Operator**;
- b) The **Daily Settlement Statement** to be rectified;
- c) The date to which the **Daily Settlement Statement** relates;
- d) The errors identified regarding the **Validated Quantities** and/or the **Imbalances**; and
- e) The supporting evidence, where applicable.

MC 17.5.3 The **SMO** shall review the submission and may liaise with the claiming **System Operator** to clarify any point of the claim.

MC 17.5.4 The **SMO** shall resolve the discrepancy within forty-eight (48) hours of receiving the request for rectification from the **System Operator**.

MC 17.5.5 The **SMO** shall **Publish** the rectified **Daily Settlement Statement** on the **ETS** as soon as possible.

MC 18. IMBALANCES IN THE REGIONAL ELECTRICITY MARKET

MC 18.1 Settlement of Imbalances

MC 18.1.1.1 The value of the energy of the **Imbalances** shall be calculated each Day and netted off within the seven-Day period of the billing cycle.

MC 18.1.1.2 The imbalance responsibilities of **Markets Participants** shall be governed by the relevant national rules and regulations.

MC 18.1.1.3 The **SMO** shall develop an **Operational Procedure** named “**Imbalance Procedure**” to determine the process for the **Settlement of Imbalances**.

MC 18.1.1.4 The **SMO** shall, on a daily basis, issue an imbalance statement to the **System Operator** in respect of the previous Day. The statement shall contain:

- a) the **Imbalances** which are the differences between **Validated Quantities** of energy during real-time operation and scheduled quantities of energy; and
- b) the financial value of the **Imbalances**, which is the **Imbalance** each hour of the **Delivery Day** multiplied by the **DAM** clearing price for that hour.

MC 18.1.1.5 The **SMO** shall issue an **Imbalance** statement each week setting out the **Imbalances** for each **Delivery Day** and the aggregate of **Imbalance** energy and costs for the previous seven (7) **Delivery Days**.

MC 18.1.1.6 The **SMO** shall issue an invoice to the **System Operator**, which could be positive or negative, in respect of the aggregate **Imbalance** costs during the billing period.

MC 18.1.1.7 The **System Operator** shall pay any incurred costs within fourteen (14) Days of receipt of the invoice or such other timeframe as specified by the **SMO**.

MC 18.1.1.8 The **SMO** shall pay to the **System Operator** any amounts owed within fourteen (14) Days of issuance of the invoice or such other timeframe as specified by the **SMO**.

MC 18.1.1.9 The **SMO** shall impose penalty on the **System Operator** whose **Imbalance** is out of the acceptable limit approved by **ERERA**.

MC 18.1.1.10 The **SMO** may require the **System Operators** who regularly fail to pay penalties for **Imbalance** to provide a bank guarantee in respect of potential **Imbalance** charges.

TITLE V – INVOICING, PAYMENT AND FEES

MC 19. INVOICING AND PAYMENT

MC 19.1 Invoicing in the DAM

MC 19.1.1 The **SMO** shall issue weekly invoices to **Market Participants** by [16:00 in D+8] only for the transactions in the **DAM** for the previous seven (7) **Delivery Days**, where D is the first **Delivery Day** of these seven (7) **Delivery Days**.

MC 19.1.2 An invoice must include:

- a) Final **Daily Settlement Statements** to which the Invoice relates;
- b) The net **Position** of the **Market Participant**, meaning the amount to be paid to or by the **SMO** including applicable market fees and levies. Whereas a positive amount implies the payment is to be made by the **Market Participant** to the **SMO**, a negative amount implies the payment is to be made by the **SMO** to the **Market Participant**;
- c) The due date and time for payment; and
- d) Any amounts outstanding from overdue payments in relation to previous Settlement statements.

MC 19.1.3 The **SMO** shall maintain a bank account with a reputable financial institution, the Settlement bank, for the sole purpose of settling market transactions. This account shall be maintained at a branch of the institution located in the Republic of Benin, the host country of the **SMO**.

MC 19.1.4 All **Market Participants** shall use the electronic funds transfer facility for payments.

MC 19.1.5 As a general rule, invoices issued to the **Market Participants** shall be payable within fourteen (14) Days of the issuing date.

MC 19.1.6 Where an invoice indicates that a **Market Participant** owes an amount greater than one (1) USD to the **SMO**, the **Market Participant** shall pay the full invoice amount to the **SMO** ,in cleared funds, by 10:00 hrs on the date specified in the invoice, whether or not it **Disputes** the amount indicated to be payable.

MC 19.1.7 Where an invoice indicates that the **SMO** owes an amount greater than one (1) USD to a **Market Participant**, the **SMO** shall pay the full amount to the **Market Participant**, in cleared funds, by 15:00 hrs on the date specified in the Invoice.

MC 19.1.8 Any late payments accrue interest at a rate defined and approved by **ERERA**.

MC 19.1.9 The **SMO** shall establish, in its books, a separate account for crediting all market fees and levies Settlement amounts payable to the **SMO**.

MC 19.1.10 The market fees and levies Settlement amount payable to the **SMO** shall be deemed paid when it is transferred into the account established by the **SMO**.

MC 19.1.11 The management of the account in MC 19.1.10 shall be in accordance with the regulation on the **ECOWAS Regional Electricity Market** fee and its related procedures.

MC 19.2 Payment in Default Situations

MC 19.2.1 Where a **Market Participant** fails to make a payment under the **Market Code** to the **SMO** by the time it is due, then the **SMO** shall draw upon any **Credit Support** concerning that **Market Participant** to meet the payment.

MC 19.2.2 Any time the total amount received by the **SMO** from **Market Participants** in cleared funds is not sufficient to make the payments which the **SMO** is required to make under the **Market Code**, for example, as a result of default by one or more **Market Participants**, then the **SMO's** liability to make those payments is limited to the amount available.

MC 19.2.3 The **SMO** must apply the available amount as follows.

- a) Firstly, the **SMO** must apply the total amount to satisfy the payment of market fees and levies Settlement amounts for the system and market operations and regulation. Where the available amount is insufficient to satisfy these first payments above, the **SMO** must reduce the payments proportionally among the system and market operations and regulation.
- b) Secondly, the **SMO** must apply the remaining amount for the **Market Participants**; but where the remaining amount after the first payments in a) is not sufficient to satisfy the payments to **Market Participants**, the **SMO** must reduce the payments proportionally. Each payment shall be based on the proportion of the remaining available amount, and the ratio shall be calculated based on the amount required to make full payments.

MC 19.2.4 If five (5) working days after a payment default, the **SMO** did not recover in full the overdue amount, then it must raise a default levy from all **Market Participants** other than **Market Participants** with unrecovered payment defaults, to cover the remaining shortfall. The **SMO** will determine the amount to be paid by each **Market Participant**, having regard to the absolute value of the energy in MWh supplied, generated or consumed, determined according to the schedules, for each **Market Participant** for hourly blocks during the most recent trading month, as a proportion of the total of those values for all **Market Participants** other than **Market Participants** with unrecovered payment defaults.

MC 19.2.5 The **SMO** must notify each **Market Participant** of the amount to be paid regarding the **Default Levy** within six (6) working days of the payment default.

MC 19.2.6 Each **Market Participant** must pay to the **SMO**, the full amount of the **Default Levy** notified by the **SMO** in cleared funds by 10:00 hrs of the 8th working day following the date of notification of the **Default Levy** payment, whether or not it disputes the amount notified.

MC 19.2.7 By 14:00 hrs on the 8th working day following the date of notification of the **Default Levy** payment, the **SMO** is to allocate the total of the **Default Levy** amounts received to the **Parties** affected .

MC 19.2.8 By the end of the second month following the end of a financial year, the **SMO** must refund all **Default Levies** raised during that financial year to the **Parties** affected from market fees.

MC 19.2.9 Where, after raising a **Default Levy**, the **SMO** recovers all or part of the relevant shortfall from the defaulting **Market Participant**, the **SMO** shall use the amount recovered to refund **Default Levy** amounts paid by other **Market Participants**. This shall be performed as soon as practicable but no later than the end of the next calendar month. The **SMO** will determine the amount to be refunded to each **Market Participant** who paid a **Default Levy**. In determining the amount to be refunded to a **Market Participant**, the **SMO** must have regard to:

- a) the amount recovered; and
- b) the default levy amount paid by the **Market Participant** as a proportion of the total of those amounts paid by all **Market Participants**.

MC 19.3 Billing in the Regional Electricity Market

MC 19.3.1 The billing for the electricity transactions in the **OTC Market** shall be the responsibility of the **Market Participants** according to their **Bilateral Contracts**.

MC 19.3.2 The billing for the **Day-Ahead Market** energy transactions shall be conducted between the **SMO** and the **Market Participants**.

MC 19.3.3 The billing for the use of **Transmission System** and the associated losses in the **Regional Electricity Market** is conducted between the **SMO** and the **Regional Compensation Parties (RCP)**.

MC 20. MARKET FEES AND LEVIES

MC 20.1 Determination of Market Fees and levies

MC 20.1.1 The levies and fees collected by the **SMO** from the **Market Participants** for the operation of the **Regional Electricity Market** are the following:

- a) Market operation fees;
- b) System operation fees;
- c) Regulatory levies; and
- d) Market participation application fees.

MC 20.1.2 The levy and fee rates shall be set to allow **SMO** to obtain a revenue equal to the estimated expenditures of the **SMO** and **ERERA** operations.

MC 20.1.3 The levy for **ERERA** operations shall be calculated and approved according to the provisions of Regulation C/REG.27/12/07 as amended on the Composition, Organisation, Functions and Operation of the ECOWAS Regional Electricity Regulatory Authority and the Regulation C/REG.14/12/23 on the ECOWAS Regional Electricity Market Fee.

MC 20.1.4 **ERERA** may set a lower **Fee** rate at the beginning of the **REM** where the existing level of exchange cannot reasonably support the estimated expenditures of **SMO** and **ERERA**.

MC 20.1.5 By 31st August of each year, the **SMO** must determine and submit its budget. **ERERA** shall approve the Fee rates based on this budget by 15th November. Before such approval, **ERERA** may require the submission of additional **Information**, materials and evidence from the **SMO**.

MC 20.1.6 Where **ERERA** has not approved Fee rates for the **SMO's** by 15th November, the **SMO** shall use the Fee rates most recently approved by **ERERA**.

MC 20.1.7 By 30th November each year, the **SMO** must Publish the Fee rates to be applied in the ensuing year, starting on the 1st of January.

MC 20.1.8 Where the revenue obtained by the approved Fees for a **Financial Year Y** is greater than or less than the actual revenue collected for that **Financial Year Y**, the fee rate for Y+2 must take it into account. The fee rate for **Financial Year Y+2** shall decrease by the amount of the surplus or increase by the amount of any shortfall, as the case may be.

MC 20.1.9 The level of each fee for **application** must reflect the estimated average costs to the **SMO** and **ERERA** of processing that **Application** and may be different depending on the type of **Market Participants**.

MC 20.1.10 For the implementation of the Regulation C/REG.14/12/23 on the **ECOWAS Regional Electricity Market** fee, **ERERA** shall adopt a detailed procedure including methods and deadlines for calculation, payment and collection of the market levies and fees.

MC 20.2 Payment of Market Levies and Fees

MC 20.2.1 The **SMO** must charge a **Market Participant** the relevant amount for the applicable fee rates, in accordance with the **ECOWAS Regional Electricity Market** Fee Procedure established in MC 20.1.10.

MC 20.2.2 The **Applicant** must pay the relevant **Application** fee upon submitting its **Application** to the **SMO or ERERA**.

MC 20.3 Payment for the Transmission Services

MC 20.3.1 The Payment of the Transmission Services will be performed following the methodology established in MC 24.

TITLE VI – MARKET MONITORING AND SURVEILLANCE

MC 21. MARKET MONITORING AND SURVEILLANCE

MC 21.1 Objectives of Market Monitoring

MC 21.1.1 The objectives of the Market Monitoring are:

- a) To detect and prevent **Market Manipulation, Insider Trading, Cartelization** and **Abuse of Dominant Position** by any **Market Participant**;
- b) To ensure that **Market Participants** have confidence in the integrity and fairness of trading in the **REM**;
- c) To ensure that the prices are obtained through a transparent and competitive process.
- d) To ensure assessment of compliance with the **Market Code** by the **Market Actors**.
- e) To ensure the neutrality of conduct of the **SMO** in case of extension of the **DAM Gate Closure Time**.

MC 21.2 Definitions of Anti-Competitive Practices

MC 21.2.1 **Market Manipulation** means the following:

- a) Entering into any transaction on the **ETS** of the **REM** which:
 - i. gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of any contract;
 - ii. secures or attempts to secure, through any staff member of the **SMO** or other **Market Actors**, a relatively higher sale price while curtailing supply to other entitled beneficiaries;
- b) Disseminating any **Information** through the media that gives, or is likely to give, false or misleading signals about the supply of, demand for, or price of any contract.

MC 21.2.2 **Cartelization** means an act by **Market Participants** who, by agreement amongst themselves, limit or control or attempt to limit or control **Generation**, distribution, sale, price or trade of electricity.

MC 21.2.3 **Unpublished Price Sensitive Information** means any **Information** relating to contracts transacted in the **REM** which is not generally available, but which upon becoming generally available, is likely to materially affect the prices in the **REM** and shall ordinarily include, but not restricted to, **Information** relating to the following:

- a) **Offers** and **Bids** of the **Day-Ahead Market**;
- b) **OTC Market** prices;
- c) **OTC** contracts.

MC 21.2.4 **Insider** means a person:

- a) Who is or has been, during the twelve (12) months prior to the concerned event, associated with the **SMO**, directly or indirectly, in any capacity, including by reason of frequent communication with its officers or by being in any contractual, fiduciary or employment relationship or by being a Director, officer or an employee of the **SMO** or by holding any position including a professional or business relationship with the **SMO** whether temporary or permanent, that allows such person, directly or indirectly, access to **Unpublished Price Sensitive Information** about transactions on the **REM**;
- b) Who is in possession of or has access to **Unpublished Price Sensitive Information** about transactions in the **REM**;
- c) Who has obtained **Unpublished Price Sensitive Information** through criminal activity.

MC 21.2.5 **Insider Trading** means:

- a) Trading, or causing another person to trade, in any **REM** contract while in possession of any **Unpublished Price Sensitive Information** relating to that contract
- b) Communicating, providing, or allowing access to any **Unpublished Price Sensitive Information**, to any person, including other **Insiders**, except where such communication is in furtherance of legitimate purposes, performance of duties or discharge of legal obligations;
- c) Recommending any person, based on **Unpublished Price Sensitive Information**, to nominate, acquire or dispose of any contract in the **REM** to which that **Information** relates.

MC 21.2.6 **Circular Trading** means when one or more **Market Participants** trade electricity among themselves, placing both **Bids** and **Offers**, directly or through related Entities, with the aim of manipulating prices, creating an artificial market, defrauding or misusing the system.

MC 21.2.7 **Abuse of Dominant Position** is the improper use of **Market Power** by a **Market Participant** to manipulate the market in order to restrict, distort or eliminate competition.

MC 21.2.8 **Capacity Hoarding**, in the context of the **Market Code**, means the acquisition of all or decisive part of the **ATC** without intentionally using it or without using it effectively.

MC 21.3 **Responsibilities for Market Monitoring and Surveillance**

MC 21.3.1 The market monitoring shall be performed by the **SMO** as established in MC 2.5.5. The responsibility of the **SMO** is the following:

- a) Implement the appropriate mechanism to collect **Information** for market monitoring;

- b) Develop and implement an **Operational Procedure** named “**Market Monitoring Procedure**”;
- c) Report immediately to **ERERA** if the **SMO** perceives any indication of a potential anti-competitive practice or **Capacity Hoarding** from a **Market Participant**.

MC 21.3.2 In market surveillance, **ERERA** shall:

- a) Approve the **Market Monitoring Procedure** prepared by the **SMO**;
- b) Specify the variables that the **SMO** requires to collect for the regular Market Monitoring;
- c) Exercise oversight responsibility through the **Market Surveillance Committee** on the Market Monitoring activities performed by the **SMO**;
- d) Conduct investigations for compliance to the **Market Code**;
- e) Analyse anti-competitive practices such as **Capacity Hoarding** or other practices that can be detected with the **Information** provided by the **SMO** and the additional **Information** collected by **ERERA**;
- f) Issue an award, decision or resolution setting out the result of its analysis and investigation related to anticompetitive practices;
- g) Impose penalties and take appropriate measures against the **Entities** and natural persons involved in anti-competitive practices.

MC 21.3.3 **ERERA** shall constitute a **Market Surveillance Committee**. The **Market Surveillance Committee** may include at least two (2) highly skilled experts from the **Electricity Supply Industry (ESI)** specifically hired by **ERERA** to provide comments, critiques and recommendations to improve the **REM**.

MC 21.3.4 The **Market Surveillance Committee** shall:

- a) Specify the variables that the **Market Surveillance Committee** requires from the **SMO** for their market surveillance activities.
- b) Recommend additional measures or improvements to the **Market Monitoring Procedure** prepared by the **SMO**;
- c) Prepare and submit a quarterly report directly to **ERERA** about the market surveillance activity.

MC 21.4 Market Monitoring by the SMO

MC 21.4.1 The **SMO** shall set up a monitoring unit to carry out day to day monitoring of transactions and undertake market analysis as mentioned in MC 21.4.3.

MC 21.4.2 The **SMO** shall ensure that only authorised personnel carry out market monitoring activities from a physically secure and access control area. **Information**, data security, and audio recording of conversations of such personnel shall be maintained by the **SMO** for a period of two years and made available to **ERERA**.

MC 21.4.3 The monitoring unit of the **SMO** shall analyse bidding patterns and transactions of the **Market Participants** and deliver a quarterly **Market Monitoring Report** based on the **Market Monitoring Procedure**. The **Market Monitoring Report** shall include, but not limited to, the following:

- a) Process for registering **Market Participants**;
- b) Mechanism for collecting data from **Market Participants**;
- c) **Information** of **Market Participants** or any other **Entities** required to provide **Information**;
- d) Specific **Information** to be provided by the **Entities** specified in clause (c) above;
- e) Periodicity and formats for reporting such **Information**;
- f) Measures to prevent any misuse of or unauthorised access to the **Information** provided by the **Market Participants**;
- g) Analytical and market monitoring activities based on the data provided by the **Market Participants**;
- h) Analytical and market monitoring activities based on the reports provided by the **SMO** as specified by **ERERA**;
- i) Any other **Information** as required by **ERERA**.

MC 21.4.4 **ERERA** may order an inquiry or investigation in accordance with this **Market Code**, where satisfied that any of the circumstances set out below exist:

- a) Non-compliance with the statutory obligations by **Market Participants**:
 - i. Violation or non-compliance with any provisions of this **Market Code**;
 - ii. Non-compliance with the decisions and resolutions of **ERERA** issued for contravention of the **REM Codes** and any other regulation;
 - iii. Delay or non-submission of **Information** sought under the **Market Code** or any other **Information** sought by **ERERA**;
- b) Involvement of **Market Participants** in any of the prohibited activities, including but not limited to the following:
 - i. **Market Manipulation**;
 - ii. Any form of **Cartelization**;
 - iii. **Insider Trading**;

iv. **Abuse of dominant position.**

MC 21.5 Market Surveillance Committee

MC 21.5.1 **ERERA** shall constitute an independent **Market Surveillance Committee** including at least two (2) highly skilled individuals with expertise in the **Electricity Supply Industry (ESI)**. No member of the **Market Surveillance Committee** shall be an employee of the **SMO**.

MC 21.5.2 The term of appointment for a member of the **Market Surveillance Committee** shall be two (2) years, renewable once. At the beginning of the committee activities and just for one time, one (1) of the appointed members shall be renewed after two (2) years and the other one after three (3) years. An old member of the Committee shall be performing his duties for one (1) year with the new member to guarantee the continuity of the activity and the knowledge transfer.

MC 21.5.3 The **Market Surveillance Committee** shall submit a quarterly **Market Surveillance Report** to **ERERA** within thirty (30) Days after the end of every quarter and shall include the following but not limited to:

- a) Transaction pattern of **Market Participants** over a specific time period;
- b) Daily, weekly, monthly volatility analysis of prices;
- c) Price setter analysis of **Buyers** and **Sellers**;
- d) Dominant position by **Market Participants**;
- e) Monitoring of **Circular Trading**;
- f) Analysis of sudden high transaction volumes of **Market Participants**;
- g) Analysis of default by any **Market Participants**;
- h) Analysis of transactions in case of congestion in the **Cross-border Interconnection** or transmission corridor;
- i) Analysis of market concentration in daily transactions; and
- j) Analysis of **Buyers** and **Sellers** whose volume were cleared at the margin.

MC 21.6 Intervention of ERERA

MC 21.6.1 **ERERA** shall receive the following reports on market monitoring and surveillance:

- a) **Market Monitoring Report** performed by the **SMO** (MC 21.4.1).
- b) **Market Surveillance Report** conducted by the independent **Market Surveillance Committee** (MC 21.5.3).

MC 21.6.2 Upon receipt of the reports referenced in MC 21.6.2 or any other specific **Information, ERERA**, following what is established on MC 21.4.4 shall give an opportunity to the concerned **Market Participant** to make a representation in connection with the reports. **ERERA** after considering the representation, if any, may by order:

- a) Require the concerned **Market Participant** to take such action as **ERERA** may deem fit; or
- b) Impose sanctions in accordance with the provisions of the **REMR** and the **REM Codes**; or
- c) Exclude the concerned **Market Participant** from participating in the relevant market of the **REM** for a period as may be decided by **ERERA**; or
- d) Direct the **SMO** to cancel their registration and participation; or
- e) **Suspend** or cancel the registration in the **REM** and the electronic platforms under the **Market Code**.

MC 21.7 Other Circumstances Requiring Intervention

MC 21.7.1 Where **ERERA** determines that a situation of abnormal increase or decrease in electricity prices or volumes in the **Day-Ahead Market** exists or is likely to occur in the **DAM**, **ERERA** may issue a resolution to:

- a) Adjust the minimum **Order** price (floor) and the maximum **Order** price (cap) on prices of electricity in **Day-Ahead Market**;
- b) Suspend transaction activities on the **Day-Ahead Market** for a cooling-off period, in case of increased volatility;
- c) Suspend transaction of any specific contract on the **REM**;
- d) Regulate the transaction fee charged by the **SMO**.

MC 21.8 Interim Measures by ERERA

MC 21.8.1 If, during an investigation or intervention, **ERERA** is satisfied that an act in contravention of the **Market Code** has been committed and/or continues to be committed or that such act is about to be committed, **ERERA** may, by a decision issue an interim order until the conclusion of such investigation or intervention.

MC 21.9 Inspections by ERERA

MC 21.9.1 **ERERA** may at any time undertake inspection, conduct inquiries or audit of the **SMO, Grid Operators** or **System Operators**, either through its employees or third parties.

MC 21.9.2 In the event **ERERA** undertakes such inspection, the **SMO, Grid Operators** or **System Operators** and employees of the **SMO, Grid Operators** or **System Operators** shall cooperate with **ERERA** for such inspection, inquiries or audit.

MC 22. ANTI-HOARDING MEASURES

MC 22.1 Capacity Hoarding

MC 22.1.1 Transmission **Capacity Hoarding** refers to an instance where a **Market Participant** acquires **PTRs** and performs the reservation of capacity through the **First-come First-served** or **Explicit Auction** mechanisms for the **OTC Market** or **Implicit Allocation** in the **Day-Ahead Market** without intentionally using it or without using it effectively.

MC 22.1.2 The instances of non-use of capacity occur when a **Market Participant** acquires capacity (**PTR**) in one direction for a given period and, at the same time or at a later time, acquires capacity (**PTR**) for the same period in the opposite direction.

MC 22.1.3 The instances of effective use of transmission capacity arise when it is used to fulfil a legitimate need of the **Market Participant** or in response to unexpected changes in the supply or **Demand** and when there is a direct and unequivocal link between these unexpected changes and the capacity used in terms of time and amount of the capacity used.

MC 22.2 Market Manipulation in Relation to Transmission Capacity

MC 22.2.1 **Market Manipulation** in relation to transmission capacity involves actions taken by **Market Participants** that artificially cause the transmission capacity (**PTR**) and/or the market prices to be at a level not justified by market forces. Such form of **Market Manipulation** includes deliberately making it appear that the **ATC** is lower than the technically available capacity. Such **Information** is likely to affect the price and capacity available in the **Day-Ahead Market**.

MC 22.2.2 The types of **Market Manipulation** include the following:

- a) False and/or misleading signals
- b) Price positioning
- c) Transactions involving fictitious nominations of capacity
- d) Dissemination of false or misleading **Information**

MC 22.2.3 Any **Nomination** of capacity which gives, or is likely to give, false or misleading signals to the **Market Participants** or the price of the **Day-Ahead Market** shall be considered **Market Manipulation**.

MC 22.2.4 Any transaction or participation in an **Explicit Auction** to obtain the **PTR** for a given period in an attempt to artificially increase the market price shall be considered a **Market Manipulation**. This constitutes a price positioning.

MC 22.3 Roles in Monitoring the Capacity Hoarding

MC 22.3.1 The **SMO** shall be responsible for performing the market monitoring (MC 2.5.5) to detect **Capacity Hoarding**, according to the concepts and definitions in this **Market Code**.

MC 22.3.2 The **SMO** shall be responsible for collecting the data required by **ERERA** to perform the assigned task of monitoring of the **ATC** and the **Capacity Hoarding** practices.

MC 22.3.3 The **SMO** shall collect **Information** from the **Explicit Auctions** to perform the operational coordination and **Capacity Hoarding** monitoring activities.

MC 22.4 Indicators to Monitor the Capacity Hoarding

MC 22.4.1 The following indicators shall be monitored by the **SMO**:

- a) **Day-Ahead Market Clearing** prices.
- b) Amount of **PTR** obtained by each **Market Participant**.
- c) Portion of the **ATC** acquired by each **Market Participant**.
- d) Time span between transactions from the same **Market Participant**.
- e) Direct or indirect reversal of transactions.
- f) Daily capacity offered in the **Day-Ahead Market**.
- g) **Nominations** of capacity by each **Market Participant**.
- h) Effective use of the **PTR** by each **Market Participant**.
- i) Any other relevant indicator.

MC 22.4.2 Monitoring the clearing prices of the **Day-Ahead Market** gives an indication of the effective use of **Physical Transmission Rights (PTR)** and their results.

MC 22.4.3 The portion of the **ATC** acquired by the **Market Participant** can help identify **Capacity Hoarding**. A decisive part of the **ATC** must be acquired for price convergence to be hindered by **Capacity Hoarding**.

MC 22.4.4 **Capacity Hoarding** implies a non-use or an ineffective use of the transmission capacity. Directly or indirectly reversing a transaction used for the **PTR's** acquisition allows the **Market Participant** to remove capacity from the market and may result in the non-use of the capacity.

MC 23. SANCTIONS AGAINST MARKET PARTICIPANTS

MC 23.1 Cases for the Imposition of Sanctions

MC 23.1.1 The competent authority responsible for imposing sanctions against **Market Participants** and the **SMO** shall be **ERERA**. Prior to imposing sanctions, **ERERA** shall conduct investigations according to applicable procedures.

MC 23.1.2 **ERERA** may impose sanctions against a **Market Participant**, following the Regulation C/REG.17/06/19, as it may be amended, in cases outlined in MC 23.1.3.

MC 23.1.3 Where the **Market Participant** violates any provision of the **Market Code** and **Operational Procedure**, in particular:

- a) Where a **Market Participant** fails to meet or inadequately meets the requirements for acquiring and maintaining the capacity of the **Market Participant**, including but not limited to:
 - i. Lack of the organizational and operational capacity.
 - ii. Failure of the **Certified Traders** of a **Market Participant** to satisfy the professional competence criteria stipulated by the **SMO**.
 - iii. Non-payment or default with respect to the payment of the required subscriptions, charges and fees of the **Market Participant** to the **SMO**.
- b) Where a **Market Participant** fails to comply with the technical instructions and specifications of the **SMO** for the use and operation of the electronic platforms for its participation in the **REM**'s trading sessions.
- c) In the event of unlawful or unauthorized use or operation of the electronic platforms used to participate in the **REM**'s trading sessions.
- d) Where a **Market Participant** fails to comply with the rules of professional conduct established by the **SMO** and **ERERA**.

MC 23.1.4 Where a **Market Participant** fails to comply with the processes adopted by the **SMO** for executing trades including but not limited to the following:

- a) Carrying out trading contrary to the terms, methods and conditions stipulated for such trading by the **SMO Operational Procedures**.
- b) Exceeding the position limits set for a **Market Participant**.
- c) Executing trades in a manner that disrupts the market's smooth operation.

MC 23.1.5 Where a **Market Participant** submits false or misleading **Information** to the **SMO**, including but not limited to the following cases:

- a) When a **Market Participant** or its **Certified Trader** is submitting its application to acquire the capacity;
- b) When a **Market Participant** requires or uses codes and accounts for the **REM**;
- c) When a **Market Participant** submits requests for the cancellation or rectification of its trades in general;
- d) When a **Market Participant** provides data, supporting documents or **Information** requested at any time by the **SMO**.

MC 23.1.6 Where the **Market Participant** fails to fulfil or inadequately fulfils any obligations undertaken according to the relevant provisions for clearing or Settlement, including but not limited to:

- a) The payment of the required guarantees and other **Collateral** in force;
- b) The compliance with the limits set to **Market Participant**;
- c) The fulfilment of the obligations arising from the clearing and Settlement of trades.

MC 23.1.7 Where a **Market Participant** fails to comply with the **SMO** notices, decisions or directives for processing and for promptly resolving outstanding matters that may arise in a clearing.

MC 23.1.8 Where a **Market Participant** becomes unable to fulfil its obligations or is deemed to be in a state of insolvency under the applicable provisions.

MC 23.1.9 Where a **Market Participant** engages in acts or omissions that prejudice the reputation and position of the **SMO**.

MC 23.1.10 Where a Market Participant engages in Market Manipulation, Abuse of Dominant Position and/or Insider Trading.

MC 23.1.11 Where a **Market Participant** is subject to sanctions imposed by its **NRA** and/or **ERERA** or other competent authorities.

MC 23.2 Categories of Sanctions against Market Participants

MC 23.2.1 **ERERA** may impose one or more of the following sanctions on a **Market Participant**:

- a) Formal written warning.
- b) Conditions or restrictions for participation in a relevant market of the **REM**.
- c) Fines as determined by **ERERA**, without prejudice to any claim for damages by the **SMO** to recover any loss caused.
- d) Prohibition from participation in the relevant markets of the **REM**.

- e) **Suspension** of the **Market Participant** for a specified period stipulated by **ERERA** on a case-by-case basis. The **Suspension** may be imposed solely on the **Certified Trader** or on the **Market Participant** in general. The right of the **Market Participant** to participate in the trading sessions shall be revoked throughout the **Suspension** period. The **Suspension** shall not discharge the **Market Participant** from its obligations towards the **SMO** to pay any amount due, including but not limited to its obligations to pay the annual fees, commissions and other amounts charged to the **Market Participant** by the **SMO** according to the **Market Code**, even if these obligations originate during the suspension period.
- f) Termination of **Market Participant's** authorisation to participate in the **REM**.

MC 23.2.2 The imposition of sanctions against a **Market Participant** shall not discharge that **Market Participant** from its liability for acts or omissions towards the **SMO** or third parties.

MC 23.2.3 *Suspension of a Market Participant*

MC 23.2.3.1 **Suspension** of a **Market Participant** shall be imposed upon the occurrence of any of the following events:

- a) The **Market Participant** is in default of payment under the **Market Code**;
- b) The **Market Participant** breaches **Prudential** obligations of MC 14;
- c) The **SMO** draws on a **Credit Support** concerning the **Market Participant** and payment under the **Credit Support** is not received by the **SMO** within ninety (90) minutes of the request;
- d) The **Market Participant** relies on a legal obstacle as a ground for non-compliance with any of its obligations under the **Market Code**;
- e) The **Credit Support** provider of the **Market Participant** is prevented or claim to be prevented from complying with any of its obligations under the **Credit Support** due to other legal or regulatory provisions;
- f) The unique identification code to trade in **ETS** ceases to be valid;
- g) The license of the **Credit Support** provider to carry on the business of providing **Credit Support** ceases to be valid;
- h) The **Credit Support** provider to the **Market Participant** ceases to carry on its business of providing **Credit Support**;
- i) The **Market Participant** or a **Credit Support** provider to the **Market Participant** becomes insolvent;
- j) A resolution is passed or steps are taken to pass such resolution for the winding up or dissolution of the **Market Participant** or its **Credit Support** provider; and/or
- k) The **Market Participant** or its **Credit Support** provider to the **Market Participant** is dissolved.

MC 23.3 Sanctions against the SMO

MC 23.3.1 **ERERA** may impose sanctions on the **SMO** in any of the following cases:

- a) Non-compliance with the provisions of the **REM Codes**.
- b) Failure to apply non-discriminatory and transparent rules and procedures in operating the **REM**.
- c) Indulgence in **Market Manipulation** or participation in **Insider Trading**.

MC 23.4 Exclusion From the Regional Electricity Market by ERERA

MC 23.4.1 Upon a proposal by the **SMO** or on its own initiative after investigations, **ERERA** may exclude, without delay, a **Market Participant** from the **REM** if the **Market Participant**, in any manner:

- a) Infringes the **Explicit Auction** provisions in the **Market Code**;
- b) Infringes the **Explicit Auctions Allocation Procedure**;
- c) Declared bankrupt;
- d) Is in default of any payment to the **SMO** and/or other **Market Participants**;
- e) Fails to top up the Collateral within five (5) working days from the date of the **PTR** allocation, to fully cover the total amount corresponding to the allocated **PTRs**;
- f) Fails to restore within five (5) working days the amount of the bank guarantee to the initial value following the execution of the guarantee;

MC 23.4.2 **ERERA** shall promptly notify the **SMO** and the **Market Participant** of the exclusion by e-mail followed by registered mail with acknowledgement of receipt. The exclusion shall take effect from the date specified in the notification.

MC 23.4.3 The exclusion from the **REM** shall not absolve the **Market Participant** of its payment obligations, such as **PTRs** obtained by **Explicit Auction**.

MC 23.4.4 The excluded **Market Participant** shall pay any outstanding invoices or claims of the **SMO** within five (5) working days after notification of its exclusion by **ERERA**.

MC 23.4.5 When the **Market Participant** is excluded from the **Explicit Auctions**, it shall lose any rights to participate in the **OTC Market** and to **Nominate** schedules.

MC 23.4.6 The **PTRs** acquired by the excluded **Market Participant** shall become available for the **Day-Ahead Market**. Where unpaid invoices remain, the **SMO** shall claim under the bank guarantee of the excluded **Market Participant**.

MC 23.4.7 An excluded **Market Participant** may apply for new registration only after paying all outstanding debts to the **SMO**.

MC 23.5 Imposition of Sanctions

MC 23.5.1 As part of the investigation process, **ERERA** shall have the authority:

- a) To request from the **Market Participant** any data or **Information** deemed necessary to investigate any case, including relevant data and audio records kept by the **Market Participant**.
- b) To require the appearance of one or more employees, representatives, or members of the management of the **Market Participant** before **ERERA**.
- c) To issue interim orders requiring the immediate cessation of practices by the **Market Participant** which may jeopardise the smooth operation of the **REM**

MC 23.5.2 Any decision imposing measures against a **Market Participant** shall be communicated in writing to the **Market Participant**. A copy of the decision shall be placed in the **Market Participant's** file, maintained by the relevant departments of the **SMO**.

MC 23.6 Enforcement of decisions

MC 23.6.1 A decision of **ERERA** imposing measures against a **Market Participant** shall be final and irrevocable.

MC 23.6.2 A decision of **ERERA** imposing measures against a **Market Participant** shall be enforced by the **SMO**. Where **ERERA** confirms that a penalty applies and specifies the amount, the **Market Participant** shall pay the amount due within thirty (30) Days from the date the decision becomes final and irrevocable.

MC 23.6.3 A decision imposing sanctions shall become final and irrevocable:

- a) On the expiry of five-Day deadline submission by the **Market Participant** of a request for the re-examination of the matter.
- b) Upon notification to the **Market Participant** of **ERERA's** decision on any request for a re-examination of the matter.

MC 23.6.4 A decision to take an immediate sanction immediately becomes final and unappealable and be executed immediately.

MC 23.7 Remedy Request Notice for Suspension Situations

MC 23.7.1 Where a **Market Participant** becomes aware of the occurrence of an event that could result in its **Suspension**, it must promptly notify the **SMO**, giving full details of the event.

MC 23.7.2 Where the **SMO** becomes aware of the occurrence of an event that could result in the **Suspension** of a **Market Participant** and that event has not been remedied, then the **SMO** must as soon as practicable:

- a) Issue a **Remedy Request Notice**, requiring that the event be remedied within twenty-four (24) hours from the time prescribed in the notice; and
- b) Draw upon the **Credit Support** of that **Market Participant**, if not already done, for the amount, it determines the **Market Participant** is actually or contingently owing to the **SMO** or any other **Market Participant**.

MC 23.7.3 Where the **SMO** has issued a **Remedy Request Notice** to a **Market Participant** with respect to the event that could result in **Suspension**, the **SMO** may extend the deadline for remedying the event by up to five (5) working days from the date and time prescribed in the **Remedy Request Notice** if the **SMO** considers that:

- a) The **Market Participant** can pay all outstanding amounts and comply in full to prudential obligations before the end of the extended deadline; and
- b) The **Market Participant** is not capable of doing so within the twenty-four (24) hours following the issuance of the **Remedy Request Notice**.

MC 23.7.4 If a **Market Participant** does not remedy a **Suspension** event before the deadline specified in the **Remedy Request Notice**, as extended, if applicable, then the **SMO** may issue a **Suspension** notice to the **Market Participant**.

TITLE VII – REGIONAL TRANSMISSION TARIFF

MC 24. REGIONAL TRANSMISSION TARIFF METHODOLOGY

MC 24.1 Objective

MC 24.1.1 The **Regional Transmission Tariff Methodology** for the **WAPP** shall be used by the **SMO** to develop a clear, transparent and predictable model that shall govern transmission pricing for the use of the **Regional** assets.

MC 24.1.2 The **SMO** shall develop an **Operational Procedure** named “Regional Transmission Tariff Application Procedure” that shall govern the determination and application of the methodology for pricing the use of the **Regional** transmission **Facilities** of the **REM**.

MC 24.1.3 Only the charges submitted by the **SMO** within the framework of the **Regional Transmission Tariff Methodology** shall be approved by **ERERA**.

MC 24.1.4 Upon the approval of the Regional Transmission Tariff Application Procedure (MC 24.1.2) by **ERERA**, the application of wheeling charge to international **Bilateral Contracts** shall be discontinued.

MC 24.2 Transmission Tariff Principles

MC 24.2.1 The following principles shall apply to the cost allocation for the use of the **Regional** transmission network:

- a) Cost Causality: The conceptual basis of the cost allocation methodology is that costs shall be allocated to the users of the **Grid** based on factors that cause the costs to be incurred. This requires that costs should be assigned to those who are responsible for them.
- b) Efficiency: Appropriate price signals to **Generation** and **Demand** give incentives for proper investment and promotes competition.
- c) Cost Reflectivity: Recover costs by reflecting the actual cost of transmission services. Security in cost recovery lowers the risk of investment and hence the cost of capital.
- d) Transparency, Fairness and Predictability: Be transparent, fair and predictable to encourage new **Market Participants**. The methodology should be easy to apply, predictable and stable in the long term.
- e) Non-discrimination: Treat network users who have the same impact on the transmission network equally. For example, ensure that the recovery of any residual costs is fairly allocated. The cost allocation shall be implementable to both **Day-Ahead Market** and **OTC Market**.

MC 24.2.2 The cost components to be allocated through the **Regional Transmission Tariff Methodology**, include:

- a) Capital costs of the **Regional** network and equipment;
- b) Operation and maintenance costs on the **Regional** network and equipment;
- c) Losses; and,
- d) Any other relevant cost approved by **ERERA**.

MC 24.2.3 The **NRAs** shall use their **Best Effort** to ensure that their national electricity tariffs are reflective of the charges and revenues associated with the application of the **Regional Transmission Tariff Methodology**.

MC 24.3 Regional Transmission Tariff Methodology

MC 24.3.1 The **Regional Transmission Tariff Methodology** and the “Regional Transmission Tariff Application Procedure” shall be approved by **ERERA** and attached in Annex D of the **Market Code**.

MC 24.3.2 The “Regional Transmission Tariff Application Procedure” shall detail:

- a) The **Information** required from the **Grid Operators** regarding their **Grid Model** including import and export as well as any other operational data needed for applying the procedure;
- b) Timeframes for submission of data to the **SMO** to ensure there is sufficient time to calculate the following year’s revenue and charge;
- c) The model adopted to allocate the cost for use of the **Regional** transmission assets and losses between the **Market Participants** and other network users;
- d) The detailed process of how the model in MC 24.3.2c) is run by the **SMO**;
- e) The mechanism to set up and approve the financial **Settlements** and timeframes for payment, as well as the **Entities** involved in the payment;
- f) The approval process for the final transmission revenues and charges; and
- g) The **Information** to be provided to **Grid Operators, NRAs, Market Participants** and **ERERA**.

MC 24.3.3 The **SMO** shall acquire and manage a computational tool for implementation of the “Regional Transmission Tariff Application Procedure”. This shall be, as far as practicable, an easy to use, auditable and repeatable pricing computational tool. This entails setting up the asset database, writing scripts to transfer data from the **Power System** model to the financial model and Settlements processes.

MC 24.4 Review and Modification of the Regional Transmission Tariff Methodology

- MC 24.4.1 **ERERA** may, from time to time, conduct a review of the Regional **Transmission Tariff Methodology** to ensure that the methodology results give the proper signal to the **Market Participants** and **Grid Operators**.
- MC 24.4.2 For the review of the **Regional Transmission Tariff Methodology**, **ERERA** shall consider the principles set out in MC 24.2 and the impact of the review on the **REM**.
- MC 24.4.3 The **SMO** shall revise the “Regional Transmission Tariff Application Procedure” to reflect any revision or modification in the methodology subject to approval by **ERERA**.

TITLE VIII – MISCELLANEOUS

MC 25. TRANSPARENCY AND INFORMATION MANAGEMENT

MC 25.1 Information and Transparency

MC 25.1.1 Market Audit

MC 25.1.1.1 No later than four (4) months after the end of each **Financial Year**, the **SMO** shall appoint one or more qualified independent auditors selected in an open tendering process to conduct an operational audit of the system operation and the market operation services, including the **Settlement** system, price calculation, auctions, scheduling, and any **Operational Procedures** relevant to the **REM**, in accordance with the **Market Code**

MC 25.1.1.2 The scope of the market audit shall include the following:

- a) The compliance of the **SMO's** internal and business processes with these rules;
- b) **SMO's** compliance with the **Market Code**;
- c) **SMO's** market software and processes for these software management;
- d) The market accounts operated on behalf of **Market Participants**.

MC 25.1.1.3 The auditor shall submit a market audit report to the **SMO** within thirty (30) Days from the date of appointment. Upon receipt of the audit report, the **SMO** shall either:

- a) Accept the report and any recommendations contained therein; or
- b) Prepare a separate report setting out findings in the market audit report, including those the **SMO** accepts, those it does not accept and the reason for its opinion.

MC 25.1.1.4 The market audit report together with any opinion of the **SMO** on that report if applicable, shall be forwarded to **ERERA** within sixty (60) Days after receiving the market audit report.

MC 25.1.1.5 **ERERA** shall approve the market audit report within thirty (30) Days of receiving the report. The **SMO** shall Publish, in the public domain of its website, the market audit report and any report it prepared within five (5) Days after **ERERA** approval including recommendations made by **ERERA**, if any.

MC 25.1.1.6 If the **SMO** fails to appoint an auditor in any year, **ERERA** may appoint an auditor to conduct the market audit required, and the **SMO** shall be responsible for the remuneration of the appointed auditor.

MC 25.1.1.7 The **SMO** shall ensure that the appointed auditor engages a qualified independent team to carry out the market audit.

MC 25.1.2 SMO Financial Audits

MC 25.1.2.1 At least once every year, the **SMO** shall appoint a qualified independent auditor to carry out a financial audit of the **SMO**.

MC 25.1.2.2 Following each financial audit, a report shall be submitted to **ERERA** and Published on the **SMO's** website for access by all **Market Actors**.

MC 25.1.2.3 The market audit and **SMO** financial audit indicative timeline of activities over a calendar year is shown in ANNEX E.

MC 25.2 Confidentiality

MC 25.2.1 General Confidentiality Obligations

MC 25.2.1.1 The **Regional Institutions** and **Market Actors** shall keep confidential, any third-party **Information** so classified, that is in their possession or they have knowledge of.

MC 25.2.1.2 **ERERA** shall determine what **Information** provided by the **Market Actors** is to be treated confidential, considering the protection of **Information** related to trade secrets.

MC 25.2.1.3 The Regional Institutions and Market Actors shall:

- a) Refrain from disclosing **Confidential Information** to any person or **Entity** unless it is in compliance with the **REM Codes**;
- b) Use or reproduce the **Confidential Information** only for the purposes for which it was provided or for the purposes specified in the **REM Codes**; and
- c) Not allow access to **Confidential Information** to unauthorized persons.
- d) Prevent unauthorized access to **Confidential Information** in their possession or control.
- e) Ensure that any person to whom they provide **Confidential Information** is made aware of the provisions of MC 25.2 concerning the confidentiality of **Information**.

MC 25.2.1.4 The **Regional Institutions** and **Market Actors**, as soon as they become aware of a breach of these provisions concerning **Confidential Information**, shall:

- a) Notify the **Entity** to whom such **Confidential Information** relates or who supplied it;
- b) Take steps to prevent unauthorized disclosure, access, use or reproduction of **Confidential Information** because of such a breach.

MC 25.2.1.5 The **Regional Institutions** and **Market Actors** shall take internal measures regarding the protection of **Confidential Information**, such as and not limited to the signing of confidentiality agreements, which enable them to comply with and monitor compliance with their obligations under MC 25.2.

MC 25.2.2 Classification of Confidential Information

MC 25.2.2.1 The confidentiality status of **Information** or documents shall fall within one of the following classes:

- a) Public, which refers to any **Information** or documents which may be made available to any person;
- b) **Market Participant**-Market Restricted, which refers to market and dispatch-related **Information** or documents which may be disclosed only to:
 - i. A specific **Market Participant**;
 - ii. The **SMO**;
 - iii. **ERERA**;
 - iv. **NRA** of a **Market Participant**'s country; and
 - v. Other government agencies or courts of a **Market Participant**'s country, in accordance with applicable laws.
- c) **Market Participant**-Network Restricted, which refers to network-related **Information** or documents which may be disclosed only to:
 - i. A specific **Market Participant**;
 - ii. Relevant **Grid Operator**;
 - iii. The **SMO**;
 - iv. **ERERA**;
 - v. **NRA** of a **Market Participant**'s country; and
 - vi. Other government agencies or courts of a **Market Participant**'s country following the applicable laws.
- d) System operations-Confidential, which refers to system operation-related **Information** or documents which may be disclosed only to:
 - i. The **SMO**;
 - ii. Relevant **Grid Operator**;
 - iii. **ERERA**;
 - iv. **NRA** of a **Market Participant**'s country; and
 - v. other government agencies or courts of a **Market Participant**'s country in accordance with applicable laws.
- e) Market operations-Confidential, which refers to market operations-related **Information** or documents which may be disclosed only to:
 - i. The **SMO**;
 - ii. **ERERA**;

- iii. **NRA** of a **Market Participant's** country; and
- iv. Other government agencies or courts of a **Market Participant's** country following the applicable laws.

MC 25.2.2.2 In establishing the confidentiality status of any type of market-related **Information** or document, the **SMO** shall be guided by the following principles:

- a) **Information** that discloses the price of electricity, capacity or any related service, equipment, or plant, or commercially sensitive or potentially defamatory **Information** relating to a **Market Participant** is not made public or revealed to other **Market Participants** except in accordance with legal requirements or requirements of the **Market Code**;
- b) **Market Participants** shall have access to **Information** on current and projected **Power system** conditions that may affect their ability to trade, deliver, or consume energy;
- c) The **SMO** may make available **Information** to any person it is required to do so by law;
- d) The **SMO** may declare its own documents under development or those from the **System Operators** to be confidential;
- e) In all cases, the confidentiality status must seek to maximise the number of **Parties** that may view the **Information** or document;
- f) **Information** already in the public domain, other than by reason of a breach of existing confidentiality obligations, is regarded to be public;
- g) The **SMO** may only disclose **Confidential Information** relating to a **Market Participant** with the consent of the **Market Participant**.
- h) **Information** that may be aggregated or provided in a form that does not disclose material that would otherwise be confidential may be made public.

MC 25.2.2.3 A **Market Participant** must not provide **Information** or documents of a given confidentiality status to any non-qualified person.

MC 25.2.2.4 A **Market Participant** may disclose **Information** or a document to any person, including another **Market Participant**, where the confidentiality status of the **Information** or document is set as public by the **SMO**.

MC 25.2.3 **Disclosure of Confidential Information**

MC 25.2.3.1 Unless otherwise provided in this **Market Code**, the following may be permitted:

- a) The disclosure, use or reproduction of **Information**, which at the time of disclosure, use or reproduction is generally known without breach of confidentiality.
- b) **Confidential Information** to a **Market Actor** may be disclosed to:

- i. An employee of the **Market Actor**, if such person requires the **Confidential Information** for the proper performance of its duties and responsibilities under the **REM Codes**;
 - ii. A legal adviser, auditor or other consultants of a **Market Actor**, where such person requires the **Information** for purposes contemplated by the **REM Codes** or under an agreement entered into pursuant to the **REM Codes**.
- c) Disclosure, use or reproduction of **Confidential Information**:
 - i. By the **Market Participant** providing the **Confidential Information** in accordance with the **REM Codes**;
 - ii. With the consent of the **Market Participant** who provided the **Confidential Information** in accordance with the **REM Codes**;
 - iii. By the **Market Participant** to whom the **Confidential Information** is provided.
- d) The disclosure, use or reproduction of **Confidential Information** required by any government or authority having jurisdiction over a **System Operator**, **Transmission Operator** or **Market Participant** for its activities within the **Regional Electricity Market**.

MC 25.2.3.2 The disclosure, use or reproduction of **Confidential Information** required in connection with legal proceedings, conciliation, arbitration, expert determination, or other mechanisms in connection with the **REM Codes** is permissible where:

- a) The provision of **Confidential Information** is necessary to protect the health and safety of persons, the integrity of **Facilities** or equipment necessary to ensure the safe and reliable operation of the **WAPPITS** or to preserve the environment;
- b) The **Confidential Information** provided pertains to an unidentifiable component or is presented as an aggregate sum; or
- c) The provision of **Confidential Information** is made by the **Market Actors** when the **WAPPITS** is in an alert or Emergency operating state, or when the **SMO** anticipates the occurrence of such a state and to the extent that the provision of **Confidential Information** will assist a **System Operator** or **Market Participant** in responding to the **Alert State** or **Emergency State** or assist the **SMO** in restoring the **WAPPITS** to a **Normal State**.

MC 25.2.3.3 Prior to disclosing **Confidential Information**, the recipients shall be informed of the confidential status of the **Information**, and all reasonable efforts, including but not limited to the signing of confidentiality agreements, shall be made to ensure that the recipient keeps such **Information** confidential and does not use it for purposes other than those referred to in this MC 25.2.

MC 25.2.4 ***Confidentiality of the OTC Market Information***

MC 25.2.4.1 Pursuant to the **Explicit Auctions Allocation Procedure**, the **SMO** may receive or gain access to **Confidential Information of Market Participants**. **Confidential Information** shall include all **Information** disclosed in writing and classified as “Confidential”, or **Information** disclosed other than in writing, **Information** as to which the recipient of such **Information** is made aware, prior to or essentially concurrent with such disclosure, that such **Information** is confidential.

MC 25.2.4.2 The **SMO** shall hold **Confidential Information** in confidence and not to disclose or make such **Confidential Information** available, in any form, to any third person or to use such **Confidential Information** for any purpose other than the compliance to the provisions of the **Explicit Auctions Allocation Procedure**, except to **ERERA** and relevant public authorities.

MC 25.2.4.3 The provisions in MC 25.2.4 shall not apply to any **Information** disclosed to the **SMO** if:

- a) Prior to such disclosure, the **Information** was a public knowledge or, after such disclosure, becomes public knowledge through no fault of the **SMO**.
- b) The **Information** was already known to the **SMO** before the disclosure.

MC 25.3 **Regional Electricity Market Website**

MC 25.3.1 ***Website Public and Private Areas***

MC 25.3.1.1 The **SMO** shall set up a dedicated website for the **REM** hosted on an internet domain independent of **WAPP** domain, not even a subdomain of any other institution.

MC 25.3.1.2 The dedicated website for the **REM** shall have a public and a private area where **Market Participants** may access **Information** related to the operations of **WAPPITS** and the **REM**, and such **Information** is not to be publicly disclosed.

MC 25.3.1.3 The private area shall be encrypted with secure access and be accessible only to **Market Participants**.

MC 25.3.1.4 The design of the dedicated website for the **REM** shall be done to facilitate public users' ability to find the required **Information** and statistics in graphics and downloadable tables. The dedicated REM website shall be designed to be user-friendly, enabling public users to easily access the required **Information** and statistics in graphical form and downloadable tables.

MC 25.3.2 ***Website Design Characteristics***

MC 25.3.2.1 The main characteristics of the website shall be:

- a) Well-designed, functional and structured to make it user-friendly, easy to consult and retrieve the required **Information** quickly.
- b) Optimize for mobile devices.
- c) Visual to clearly understand the parameters and variables through charts and graphics.
- d) Integrated with the internal database and applications of the **SMO**.
- e) Written in clear, non-technical language that is easily understandable by all stakeholders, regardless of their technical background
- f) Optimized for search and social web.
- g) Extendable in design to allow easy extensions in the future for new website areas and incorporate new markets.

MC 25.3.3 **Website Content**

MC 25.3.3.1 The **SMO** shall determine the scope and formats of **Information** Published on the website, and may update from time to time. At a minimum, the following **Information** shall be Published:

- a) **Information** on the nature and operation of the market.
- b) **Information** on market performance.
- c) Reports and documents, including its own financial reports.
- d) The list of the confidentiality status of **Information** and documents;
- e) The current version of the **Market Code**;
- f) Any rule amendment proposals that are open to public comment;
- g) **Information** on any amendment to the **Market Code** that have been made according to the amendment process;
- h) Details of all **Market Participants** including:
 - i. name;
 - ii. physical address;
 - iii. mailing address, e-mail address and telephone;
 - iv. details of applicable licenses and authorisations held.
- i) The precise basis for determining the bank rates.
- j) For each hourly block in each completed Day of operations since the commencement of the market, as well as during the previous 12, 6, 3 and 1 calendar months and 7 **Days** and 1 **Day**, key **Information** on market developments, such as aggregated quantities offered for trade and actually traded, clearing prices and other relevant market **Information**.

- k) Where available, balancing forecast and network availability forecast.
- l) Loss factors for each network.
- m) Details of resolved **Disputes**, including all public **Information** associated with the **Dispute**, but not aspects of the resolution or **Information** associated with the resolution which, in accordance with its confidentiality status class, cannot be made public.
- n) Public consultation proceedings.
- o) Public reports about the **REM**.
- p) Incident reports explaining what happened during unusual market or dispatch events but not aspects of such reports which, in accordance with its confidentiality status, cannot be made public.
- q) The **SMO** budget for the current financial year.
- r) Fee schedule for services provided by the **SMO**, and all other market fees.
- s) Summary **Information** of the bank account maintained by the **SMO** for market Settlement for the preceding 12, 6, 3 and 1 calendar months, including the end of month balance.
- t) Summary **Information** on **Disputes** in progress that may impact other **Market Participants**.
- u) Audit reports;
- v) Documentation on the functionality of any software used to run the market and/or **Settlements**.
- w) **Information** relating to commissioning tests.

MC 25.3.4 **Information Regarding Planned and Unplanned Works**

MC 25.3.4.1 The **Market Participants** shall provide **Information** regarding planned and unplanned works as may be necessary for the **SMO** to Publish the following **Information** in the private area of its website, accessible to all **Market Participants**:

- a) The planned works for the **WAPPITS** and the **Relevant Grid**; and,
- b) The program of any modification not included in the planned works, specifying the equipment expected to be unavailable based on **Information** provided by each **System Operator**.

MC 25.3.5 **Market Participant Specific Data**

MC 25.3.5.1 The **SMO** shall Publish the following **Information** in the private and secure area of the website, which will be accessible to the relevant **Market Participant**, the relevant **Credit Support** provider, and the **SMO** only:

- a) The details of the historic and current transactions in the **REM** by the **Market Participant**, including **Information** regarding quantities and value of the transactions as acknowledged by the relevant **Market Participant**;
- b) The quantity of **PTR** obtained by the **Market Participant**; and,
- c) The outstanding amount payable by the **Market Participant**.

MC 25.3.6 **Statistics**

MC 25.3.6.1 The **SMO** shall Publish daily, monthly, quarterly and yearly statistics related to the **REM** in a secure area of the website, accessible to all **Market Participants**.

MC 25.3.6.2 The **SMO** shall Publish at least the following historical data:

- a) An hourly actual transmission carrying capacity of each **Cross-border Interconnection**;
- b) Quantity of electricity hour-by-hour metered at the **Defined Metering Points** of the **Cross-border Interconnections**;
- c) Actual monthly and yearly energy at the **Defined Metering Points** of the **Cross-border Interconnections** ; and
- d) The **Information** on **Cross-Border Transactions**.

MC 25.3.6.3 The **SMO** shall Publish at least the following operational indicators to assess the performance of the **WAPPITS**:

- a) Number of outages during each month on the **Cross-border Interconnections**;
- b) System Average Interruption Duration Index (SAIDI) due to outages on the **Cross-border Interconnections**;
- c) System Average Interruption Frequency Index (SAIFI) due to outages of **Cross-border Interconnections**;
- d) The daily incident reports (if any) of the **WAPPITS** and interconnected part of the Grid of the **Market Participants**;
- e) Frequency deviation Indicator and voltage deviation indicator;
- f) **Energy Not Served** by **Cross-border Interconnection**; and
- g) Average time delay for communication and switching/operational activities with respect to the agreed time durations.

MC 25.3.6.4 The **SMO** shall Publish at least the following market indicators to assess its performance:

- a) Average time of publication delay per topic for each type of market of the **REM**.

- b) Market structure of the **Member States**: number of **Generation** companies, transmission companies, distribution companies, traders and big Loads that are **Market Participants**.
- c) The share of energy **Generation** from each **Member State** in the total energy trade in the **REM**.
- d) Daily **Cross-border Interconnection** capacity and its Load factor.
- e) Daily offer to the **Day-Ahead Market**.
- f) Percentage of non-**Nominated PTR**.
- g) Effective use of the **Cross-border Interconnections** per flow direction.

MC 25.3.7 ***Backup of Information and Data***

MC 25.3.7.1 The **SMO** shall maintain a backup of all the **Information** Published on the website in a secure location, accessible only to the **SMO**.

MC 25.3.7.2 The backups of the data and **Information** Published on the **SMO**'s website shall be retained for an unlimited period of time"

MC 25.3.8 ***Security***

MC 25.3.8.1 The website shall be hosted on a network designed within a demilitarized zone (DMZ) to avoid intrusion into the main databases and systems of the **SMO**.

MC 26. DISPUTE RESOLUTION

MC 26.1 The General Process

MC 26.1.1 When a **Dispute** arises, the **Parties in Dispute** shall, within 30 **Days**, make bona fide efforts to negotiate and resolve the **Dispute** before filing a **Notice of Dispute**. Each **Entity** who is a **Party** to a **Dispute** shall, to this end, designate an individual of sufficiently senior status in its organization with authority to negotiate. The period for negotiation of thirty (30) Days can be extended by mutual agreement of the **Parties**.

MC 26.1.2 If, after thirty (30) **Days** of efforts (or the period agreed by the **Parties**) no agreement has been reached, any **Party** to the **Dispute** may:

- a) Initiate the **Dispute Resolution** process established in the “Articles of Agreement” of the **WAPP** (Accra, October 2005) by filing the corresponding **Notice of Dispute** according to the procedure's provisions.
- b) File a **Notice of Dispute** directly to **ERERA** and initiate the **ERERA Dispute** resolution procedure. The **Parties**, in this case, have to demonstrate that they have not arrived at an agreement after trying to solve the **Dispute** amicably.

MC 26.1.3 The resolution of **ERERA** will be final and enforceable according to the **Dispute** resolution procedure approved by **ERERA**.

MC 26.2 Application

MC 26.2.1 Without prejudice to the general **Dispute** resolution provisions in the **General Conditions**, this MC 26 sets out the **Dispute** resolution procedure applicable to any **Dispute** concerning:

- a) The application or interpretation of the **Market Code**.
- b) The failure of **Market Participants** to reach an agreement on a matter where the **Market Code** requires such agreement or requires the **Market Participants** to negotiate in good faith to reach an agreement.
- c) The payment of money or the performance of any obligation under the **Market Code**.

MC 26.2.2 The provisions in MC 26.5 shall be construed to secure the most expeditious, just and least expensive determination on its merits of every proceeding conducted hereunder

MC 26.2.3 The **Dispute Resolution** procedure provided in the **Market Code** shall apply to:

- a) any **Dispute** between the **SMO** or a **Transmission Operator, System Operator** or any **Market Participant** which arises under, in connection, or concerning the **Market Code**;
- b) **Disputes** relating to a denial order issued by the **SMO** to any **Entity** to participate in the **REM**;
- c) **Disputes** referring to or in connection with the **REM** transactions and operation;
- d) **Bilateral Contracts** operating in the **REM** may have their own **Dispute Resolution** procedure, and this procedure will prevail over these provisions if the **Parties** to the **Bilateral Contract** have agreed so; and
- e) **Bilateral Contracts** signed after the **REM** has begun, **Disputes** on any matter referring to or in connection with the use of the **WAPPITS** will be dealt with as described in MC 26.5.

MC 26.2.4 The **Dispute** resolution Procedure provided herein shall not apply to:

- a) A matter that arises under a **Bilateral Contract** between **Market Participants** unless the **SMO** is a **Party** to the contract, or the contract provides that this **Dispute** resolution process applies.
- b) **Disputes** relating to a proposal to amend any provision of the **Market Code**.
- c) **Disputes** between the **SMO** and a **Market Participant** relating to the amount chargeable by the **SMO**, unless the **Dispute** relates to or is connected with the calculation process of the charge payable by the **Market Participant**.
- d) An award of an arbitrator made under the **Market Code**.

MC 26.2.5 In this **Market Code**, the “**Parties in Dispute**” shall be the **Market Participants** raising the **Dispute**, the **SMO** and any other **Market Participants** named in or joined to the **Dispute**.

MC 26.2.6 The **Parties in Dispute** shall avoid any action to resolve a **Dispute** with processes inconsistent with the **Market Code**.

MC 26.3 First Stage Dispute Resolution

MC 26.3.1 Where a **Market Participant** decides to initiate a **Dispute** with other **Market Participants** concerning a matter to which this **Dispute** resolution process applies, it may issue a **Notice of Dispute** to the **SMO** and the other **Market Participants** who are **Parties** to the **Dispute** within

twelve (12) months of the matter giving rise to the **Dispute**. A copy of the **Notice of Dispute** shall be sent to **ERERA**.

MC 26.3.2 The **Market Participant** initiating the **Dispute** may name any **Market Participant** in a **Notice of Dispute** it considers affected by the **Dispute** or its resolution.

MC 26.3.3 The **Notice of Dispute** shall be in writing and must contain:

- a) The date of issuance;
- b) The identity of the initiating **Market Participant**;
- c) The identities of all **Parties in Dispute** ;
- d) A detailed description of the **Dispute**, including a description of the actions in **Dispute**, and the time and date when the actions in **Dispute** occurred; and
- e) The official e-mail and registered postal address of the initiating **Market Participant** and the contact details of its representative **Market Participant**.

MC 26.3.4 A **Market Participant** receiving a **Notice of Dispute** shall acknowledge receipt of the **Notice of Dispute** and provide its registered postal address, official e-mail and details of its contact person within two (2) working days of receipt of the **Notice of Dispute**.

MC 26.3.5 Where the **SMO** considers that a **Market Participant** not named in a **Notice of Dispute** may be affected by the **Dispute** or resolution of the **Dispute**, it shall, within ten (10) working days of receiving the **Notice of Dispute**, request the **Parties in Dispute** to join such **Market Participant**.

MC 26.3.6 The designated representatives of the **Parties in Dispute** with authority to resolve the **Dispute**, shall make reasonable endeavours to attempt in good faith and with **Best Efforts** to resolve the **Dispute**.

MC 26.3.7 A **Dispute** shall be escalated to the second stage of the **Dispute** resolution process if the **Parties in Dispute** fail to resolve the **Dispute** within:

- a) A mutually agreed period; or
- b) thirty (30) Days from the date of the **Notice of Dispute**, where no time period is agreed by all **Parties in Dispute**.

MC 26.3.8 Notwithstanding these provisions, the resolution of any **Dispute** among **Market Participants** shall comply with the **Dispute** resolution MC 26.5 established in the **Market Code**.

MC 26.4 Second Stage of the Dispute Resolution Process

MC 26.4.1 If any **Dispute** is not resolved in the first stage, then the **Parties in Dispute** may subject the **Dispute** to the **Dispute Resolution** Procedure as provided in MC 26.5 of this **Market Code**.

MC 26.5 Dispute Resolution Procedure

MC 26.5.1 *Dispute Resolution Confidentiality*

MC 26.5.1.1 Any **Party in Dispute** may declare any document or **Information** contained in any document required to be produced during the **Dispute** resolution process as **Confidential Information**. The **Party in Dispute** making such declaration shall provide written justification to the corresponding authority. If the corresponding authority accepts the claim of confidentiality, the corresponding authority shall establish such procedures as may be necessary to protect the confidentiality and commercial value of such document or **Information**.

MC 26.5.1.2 **Parties** involved in the **Dispute** resolution process shall enter into such confidentiality agreement as may be needed.

MC 26.5.2 *Record-Keeping and Publication*

MC 26.5.2.1 **ERERA** shall maintain a record of all **Dispute** resolution proceedings conducted under this Article MC 26. **ERERA** shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such records which constitute **Confidential Information**. For this purpose, such **Information** may be sealed and marked as “CONFIDENTIAL” or otherwise labelled as being confidential.

MC 26.5.2.2 Notwithstanding the confidential matters, **ERERA** shall arrange for publication on **ERERA**’s website of the following:

- a) The matters of the **Dispute**;
- b) Notice of the appointment of experts who will resolve the **Dispute** (conciliators, an arbitration tribunal of the body that **ERERA** decides will deal with the **Dispute**);
- c) Notice of the date, time and place fixed for hearings, if any; and
- d) A summary of the award.

MC 26.5.2.3 Any award made by **ERERA** or an arbitrator pursuant MC 26.5 shall:

- a) Be binding on the **Parties in Dispute**;
- b) Be enforceable;
- c) Have the possibility of being subjected to appeal at the **ECOWAS** Court of Justice on matters of law. Until and unless the **ECOWAS** Court of Justice modifies the award by **ERERA** or an arbitrator, the award shall be enforceable, and non-compliance shall constitute an event of default under the **Market Code**.

MC 26.5.3 *Continuing Obligations and Stay of Orders*

MC 26.5.3.1 Where a **Dispute** involves the payment or recovery of monetary amounts due under the **Market Code**, other than payment of a financial penalty, the amount shall be due and payable at the time specified for payment under the **Market Code**, notwithstanding the initiation of a **Dispute Resolution** procedure.

MC 26.5.3.2 Where a **Dispute Resolution** is initiated that involves payment of a financial penalty imposed by the **SMO** on a **Market Participant**, the obligation to pay that financial penalty shall remain until delivery of an award.

MC 27. AMENDMENTS OF THE MARKET CODE

MC 27.1 General Amendment Process

- MC 27.1.1 An amendment to the **Market Code** shall follow the procedure set out in the **General Conditions**.
- MC 27.1.2 This MC 27 provides additional procedures applicable to amendment process for the **Market Code**.
- MC 27.1.3 Any proposal for amendment to the **Market Code** shall be drafted by the **SMO** in consultation with the **Market Participants** ensuring that **ERERA** is informed of the process.
- MC 27.1.4 All amendments shall be submitted to **ERERA** for approval.

MC 27.2 Amendments of the Market Code

MC 27.2.1 *Market Code Report*

- MC 27.2.1.1 Every six (6) months specifically in the first week of February and August, the **SMO** shall prepare a **Market Code** report describing the challenges in the implementation and application of the **Market Code** and complementary **Operational Procedures**. The report shall be submitted to **ERERA, NRAs, Market Participants, Grid Operators** and **Transmission Operators**.

MC 27.2.2 *Proposals to Amend the Market Code*

- MC 27.2.2.1 A proposal to amend the **Market Code** may be initiated by:

- a) **ERERA.**
- b) **WAPP.**
- c) The **SMO.**
- d) An **NRA** of one of the **Member States**.
- e) A group of at least four (4) **Market Participants**, from at least two (2) different **Member States**.
- f) Any **Entity** through any of the **Market Actors** referred to in subparagraphs (a) to (d) above.

MC 27.2.3 *Initiation of Amendments*

MC 27.2.3.1 An amendment shall be initiated in accordance with the provisions set out in the **General Conditions** and shall be considered by **ERERA** in a quarterly regulatory report.

MC 27.2.3.2 The following principles shall apply in the drafting of the proposal for amendment:

- a) The initial amendment shall be prepared by the **SMO** in consultation with **Market Actors**.
- b) The amendments shall be prepared in a transparent manner, giving all stakeholders the opportunity to contribute.
- c) The amendments shall include provisions for modification when required, in accordance with the principles stated in MC 27.1.3 for the initial drafting.
- d) **ERERA** shall be kept informed of the process at all stages.
- e) The entire process shall be documented, and the records shall be made available to interested **Market Actors**.
- f) **ERERA** may approve or reject the proposed amendments.

MC 27.2.4 *Conditions for Rejection of Proposal of Amendments*

MC 27.2.4.1 Without prejudice to the reviewed and approval process of major amendment to the **REM Codes** specified in the **General Conditions**, **ERERA** may reject a proposed amendment to the **Market Code** if, in its opinion, the proposed amendment:

- a) Unfairly discriminates against a **Market Participant** or category of **Market Participants**;
- b) Restricts competition or prevent free entry into the **REM**;
- c) Enables one or more **Market Participants** to obtain or retain abusive market power;
- d) Creates potential for abuse of market power by one or more **Market Participants**; and/or
- e) Is not conducive for the efficient and economic operation of the **REM**.

MC 27.3 **Enforcement and Compliance**

MC 27.3.1 Without prejudice to the compliance provisions of the **REM Codes** outlined in the **General Conditions**, it is hereby specified that:

- a) The **SMO**, **Grid Operators** or **System Operators**, **Market Participants** and **Transmission Operators** shall comply with the **Market Code** including any amendment or modification that has been dully approved.
- b) The **SMO** shall ensure compliance with this **Market Code** by **Market Participants**, **Grid Operators** and **Transmission Operators**, and shall report any breach of the **Market Code** to **ERERA**.

- c) Any **Market Participant, Grid Operator** or **Transmission Operator** having evidence of a violation of the **Market Code** by another **Market Participant, Grid Operator, Transmission Operator** or the **SMO**, shall report the violation to **ERERA**.

ANNEXES

ANNEX A – Procedure for Authorisation to participate in the Regional Electricity Market

A 1. Application Form to become Market Participant

- A 1.1.1 To participate in the **REM**, an applicant shall submit an application form as prescribed by **ERERA**.
- A 1.1.2 **ERERA** may amend and change the application form from time to time according to its evaluation of the **Regional Electricity Market** evolution and requirements.

ANNEX B – Bilateral Contracts - Minimum Requirements

B 1. Minimum Requirements for Bilateral Contracts

- B 1.1.1 The **OTC Market** is a framework for the exchange of electricity where transactions take place directly between the **Parties**. However, any **Bilateral Contract** shall comply with the **Regional Electricity Market Regulation**.
- B 1.1.2 **Bilateral Contracts** shall follow the models of **Bilateral Contracts** approved by **ERERA** in Resolution No 9/**ERERA**/17 of August 9, 2017 as updated from time to time.
- B 1.1.3 **ERERA** may amend and change the guidelines for the **Bilateral Contracts** from time to time according to their evaluation of the **OTC Market** evolution and requirements.

ANNEX C – Regional Market Participation Agreement

C 1. Agreement for the Regional Day-Ahead Market

- C 1.1.1 To participate in any type of market in the **REM**, a **Market Participant** shall sign an agreement with the **SMO** in accordance with the procedure prescribed by **ERERA**.
- C 1.1.2 **ERERA** may Amend and change the mandatory Agreement for participating in any type of market of the **REM** according to its evaluation of the **REM** evolution and requirements.

ANNEX D – Transmission Tariff Methodology

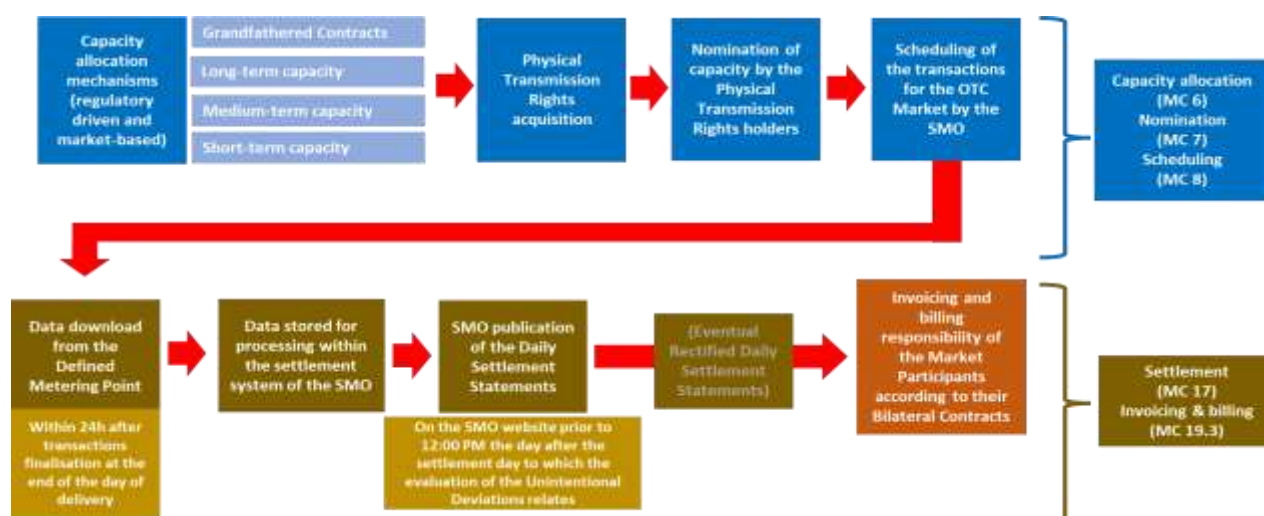
D 1. Regional Transmission Tariff Methodology

D 2. Regional Transmission Tariff Application Procedure

ANNEX E – Key Indicative Timelines and Deadlines Over a Calendar Year According to the Market Code Provisions

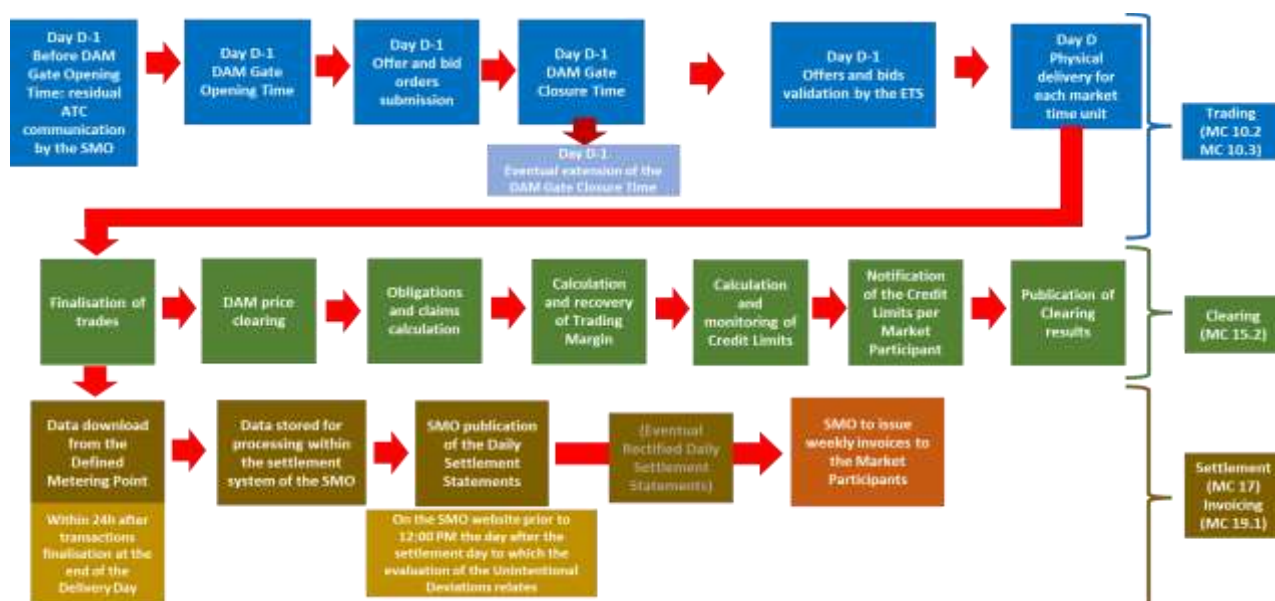
E 1. OTC Market Indicative Timeline

E 1.1.1 The following figure describes the indicative Regional **OTC Market** timeline based on the provisions set in relevant sections of the **Market Code**. The figure shall be for illustration purpose.



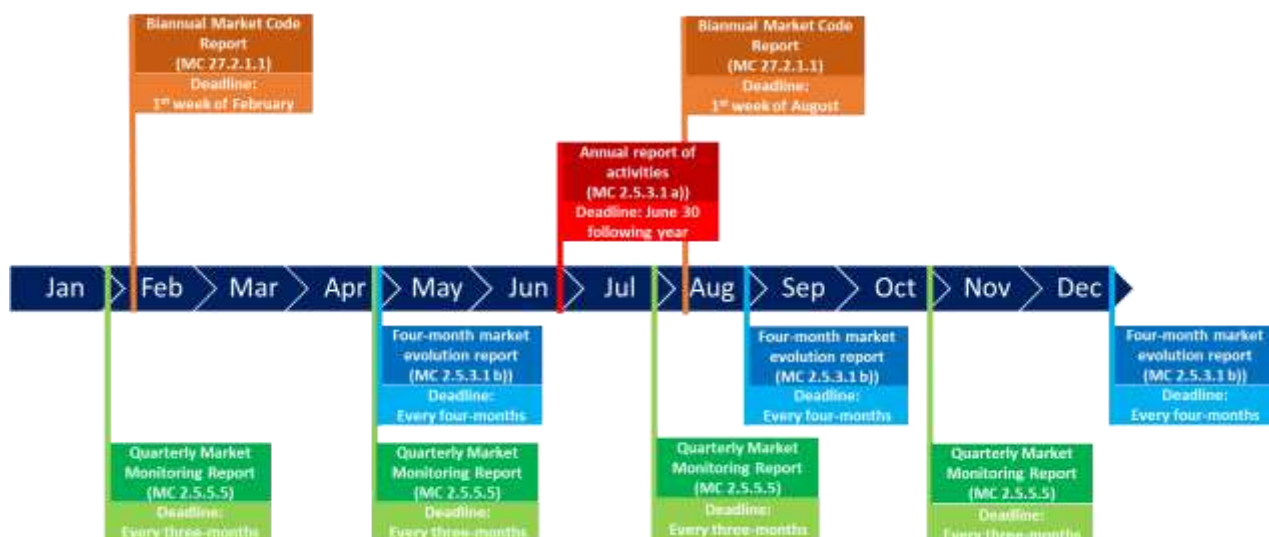
E 2. DAM Indicative Timeline

E 2.1.1 The following figure describes the indicative Regional **DAM** timeline based on the provisions set in relevant sections of the **Market Code**. The figure shall be for illustration purpose.



E 3. SMO reporting Deadlines over a Calendar Year

E 3.1.1 The following figure describes the **SMO** reporting deadlines over a calendar year based on the provisions set in relevant sections of the **Market Code**. The figure shall be for illustration purpose.

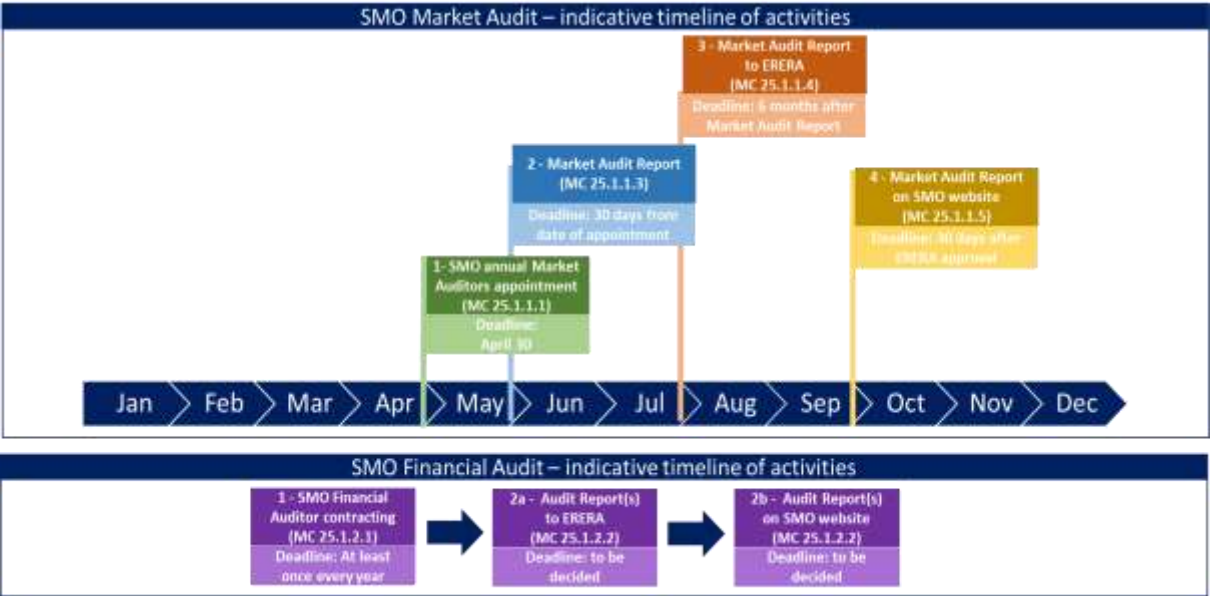


E 3.1.2 The following table summarizes the key purpose of each report to be produced by the **SMO**.

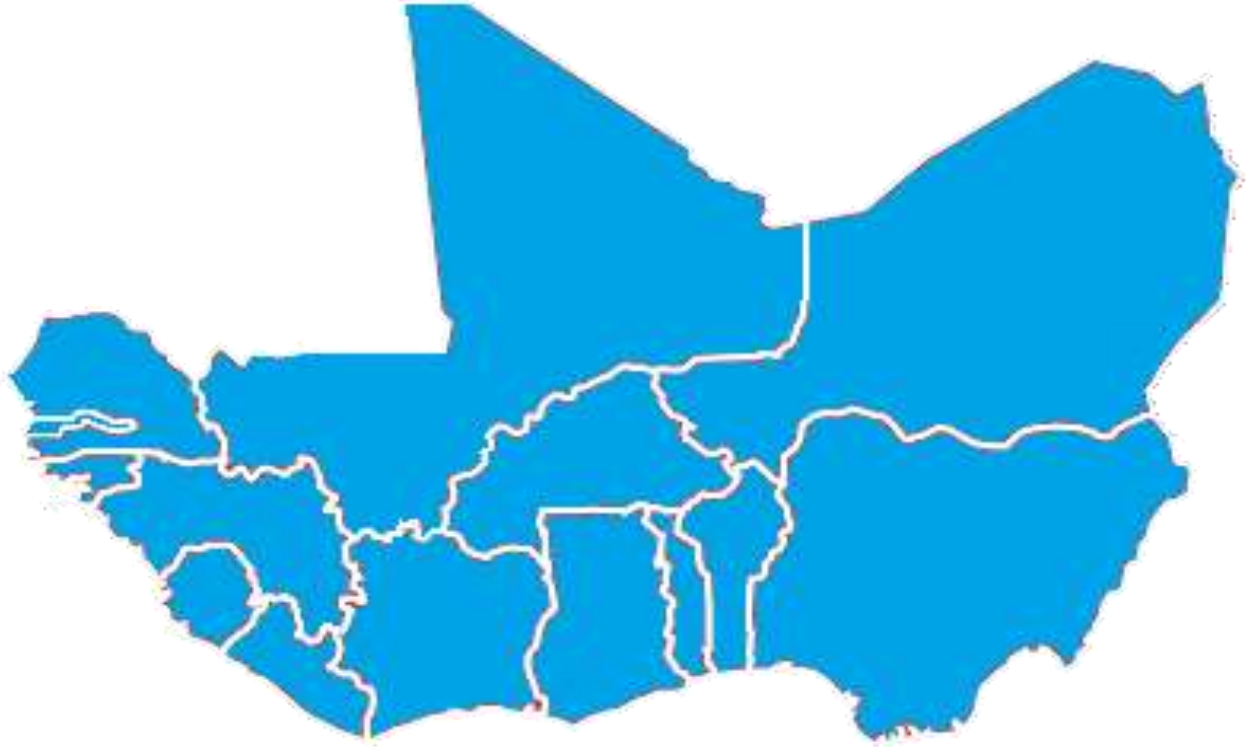
Report name	Purpose
Market Monitoring Report	The monitoring unit of the SMO shall analyse bidding patterns and transactions of the Market Participants and deliver quarterly Market Monitoring Report based on the Market Monitoring Procedure . The SMO shall verify that all Market Participants comply with the Market Code .
Market Code Report	Every six (6) months, (on the first week of February and August), the SMO shall prepare a Market Code report describing the problems experienced by the SMO in the implementation and application of the Market Code and any Operational Procedures .
Market evolution report	Summarized report to be produced every four (4) months to describe the REM evolution.
Annual report of activities	Annual report of activities including market performance, financial statements, and operational Disputes to be sent to ERERA no later than June 30 of the following year

E 4. SMO Market and Financial Audit indicative Timeline of Activities over a Calendar year

E 4.1.1 The following figure describes the **SMO** indicative timeline over a calendar year of activities related to the **Market Audit** and Financial Audit based on the provisions set in the pertinent sections of the **Market Code**. The figure only has an illustrative purpose.



REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



MTC – METERING CODE

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MTC 1. INTRODUCTION

MTC 1.1.1 The **Metering Code** sets out the minimum requirements for metering in the **Regional Electricity Market (REM)**.

MTC 1.1.2 The following terms are adopted in this **Metering Code** to distinguish and properly assign the metering functions to involved **Entities**:

- a) “**System Operator**” refers to a subset of the “**Grid Operator**” and represents the **Entity** in charge of the **Functional Operation** of the **Power System** and the **Cross-border Interconnections** at any voltage level.
- b) “**Transmission Operator**” means a subset of the “**Grid Operator**” and represents the **Entity** that owns a whole or part of the **Grid** assets, and it is responsible for the **Physical Operation**, the security, and maintenance of such assets.

MTC 1.1.3 Given the different unbundling status of the electricity sector within each **Member State**, the **System Operator** and **Transmission Operator** may represent two (2) independent national **Entities**, or two (2) departments of the same independent **Transmission System Operator (TSO)**, or two (2) departments of a vertically integrated utility.

MTC 1.1.4 **Metering Data** from **System Operators** shall be required for the accurate settlement of the traded electricity in the **Regional Electricity Market**. This **Metering Code** sets the technical references or standards for the measurement of power and energy import and export flows at each **Interchange Point** identified as custody transfer points between the participating **System Operators**.

MTC 1.1.5 The **Metering Code** specifies the minimum technical, design and operational requirements or standards to be complied with for the accurate **Metering** of energy transfers at each **Interchange Point** between **System Operators**, and between **System Operators** and **Non-WAPP Grid Operators**. The **Metering** at the **Interchange Points** is required for accurate accounting of energy exchange for financial purposes and for the accounting of inadvertent deviations in line with the **Operation Code** and **Market Code**.

MTC 1.1.6 The **Metering Code** also specifies the requirements for the associated electricity market and **Operational Data** related to **Metering** procedures required for the compliant operation of the **Regional Electricity Market**, under the auspices of the **SMO**.

MTC 1.1.7 The **Metering Code** shall not apply to **Metering** for commercial transactions at the national level. The **Metering Equipment** used for commercial transactions at the national level shall be subject to **National Grid Codes**, regulations or **Power Purchase Agreements**.

MTC 1.1.8 The **Metering Code** shall not apply to the following areas of responsibilities:

- a) the management of **Data Exchange** from **System Operators** or other electricity **Market Participants**; and,

- b) the responsibilities of the **SMO** in relation to the storage of **Metering Data** and the provision of the **Common Information** to **Grid Users**.

MTC 1.1.9 The area of responsibilities in MTC 1.1.8 are subject to the relevant sections of the other **REM Codes** concerning **Data Exchange** and **WAPP** policies, under the regulatory oversight of **ERERA**.

MTC 2. OBJECTIVE

MTC 2.1.1 The objective of the **Metering Code** is to outline common principles, specify minimum technical standards, design requirements and establish basic data collection rules for **Transmission Operators**, **System Operators** and other actors in the **REM**.

MTC 3. RESPONSIBILITY, ACCESS AND MAINTENANCE

MTC 3.1 Responsibility and Access to the Metering Equipment

MTC 3.1.1 The **Metering Equipment** shall be procured, owned, installed and maintained by the **Transmission Operators** of the **Member States**.

MTC 3.1.2 The **Metering Equipment** and the metering system shall be procured with the technical characteristics specified in this **Metering Code** and shall be interoperable with the metering system installed by the **System Operators** and the **SMO**.

MTC 3.1.3 The **Transmission Operator** shall have exclusive physical access to the **Metering Equipment** located in their **Facilities**. In case of **Disputes** under the jurisdiction of the **NRA** and/or **ERERA**, the **Transmission Operator** shall grant permission to authorised personnel to access the physical equipment and the metering information to perform audits.

MTC 3.1.4 For the purpose of the system operation and the transactions in the **Regional Electricity Market**, the **Transmission Operator** shall grant access to the **Main Meter** and **Check Meter** to the relevant **System Operators** of the **Member States** and the **SMO**.

MTC 3.1.5 The relevant **System Operators** and the **SMO** shall be able to remotely access the **Meters** and remotely read the registered variables via a secure and encrypted communication means.

MTC 3.1.6 For security reasons, only two (2) authorised staff members from the **System Operator** and two (2) authorised staff members from the **SMO** shall have access to remotely read the Meters. These staff members shall be clearly identified with the full name, physical address, e-mail address, cell phone number for contact. Authorised personnel shall be fully responsible for the use or misuse of the information obtained from the **Main Meter** and/or **Check Meter**.

MTC 3.1.7 A declaration form shall be signed by each authorised personnel with access to the **Metering System** and the **Main Meter** and **Check Meter's** information.

MTC 3.1.8 Any troubleshooting and problem with remotely accessing the **Main Meter** and/or **Check Meter**, shall be immediately communicated to the relevant **Transmission Operator**.

MTC 3.2 Maintenance of Metering Equipment

MTC 3.2.1 **Metering Equipment** shall measure and record the active and reactive energy, as well as active and reactive power transferred into or out of a **Control Area** at the **Interchange Point** with another **Control Area**. This **Metering Equipment** shall be the primary source of data for **System Operators** and the **SMO** to account for **Unintentional Deviations**.

MTC 3.2.2 The **Metering Equipment** shall measure and register the variables established and indicated by the **SMO** and the **System Operators** according to the established **Market Time Units** for the **Regional Electricity Market**.

MTC 3.2.3 **Transmission Operators** shall be responsible for the maintenance and operation of the **Metering Equipment** installed at each **Defined Metering Point (DMP)**, and for the initial design, installation, testing and commissioning of the **Main Meters** and **Check Meters**.

MTC 3.2.4 **Metering Equipment** for the **Main Meter** and the **Check Meter**, procured, installed, operated and maintained, shall comply with the accuracy standards in relation to **Meters** and **Metering Equipment** as set out in this **Metering Code**.

MTC 3.3 General Requirements

MTC 3.3.1 The **Metering Equipment** for the measurement and recording of electrical energy transfer on the interconnections between **System Operators** and between **System Operators** and **Non-WAPP Grid Operators** shall comply with the technical requirements in this **Metering Code**. The provisions of the **Metering Code** shall equally apply to the **Main Meter** and the **Check Meter**

MTC 3.3.2 The **Transmission Operators** shall establish **Metering** related policies, **Codes of Practice**, and procedures based on common standards including, but not limited to, registration in the **Metering Database**, testing and certification, sealing, loss adjustments, data security, inspection, testing and audit of **Metering Equipment** and measurement error correction.

MTC 4. METERING STANDARDS

MTC 4.1 Objectives of Metering Standards

MTC 4.1.1 The objective of the metering standards is to ensure the accurate, proper and correct settlement and billing for the **System Operators** as well as **Market Participants**. The **Metering**

Code outlines the requirements for applying uniform standards, specifications and **Codes of Practice** underpinning the validity of data for settlement and billing purposes.

MTC 4.1.2 The Rules and obligations governing compliance with this **Metering Code** are set out in the **General Conditions**, that include the framework to revise and adjust the **REM Codes** over time.

MTC 4.2 Applicable Metering Equipment Standards

MTC 4.2.1 The IEC metering accuracy standards at the highest accuracy level shall apply to both the **Main Meter** and the **Check Meter**, and the highest accuracy standards shall also be required for **Current Transformers (CTs)** and **Voltage Transformers (VTs)**.

MTC 4.2.2 Where IEC standards are not nationally recognized or have not yet been legally ratified by a **Member State**, equivalent internationally recognized standards with legal validity in that **Member State** may be applied, provided that, at a minimum, the IEC standards referenced in Annex A – Application of Standards are observed.

MTC 5. METER INFORMATION REGISTER

MTC 5.1 Register Content

MTC 5.1.1 The **Metering Database** of both the **System Operators** and the **SMO** shall contain a **Meter Information Register** of all **Meters**. This register shall contain but not be limited to:

- a) A unique **Meter** identification.
- b) The location of the **Main Meters**, **Check Meters** and any other **Metering Equipment** including **Metering Data** recording systems.
- c) The identification of the concerned **Transmission Operator**.
- d) **Meter** manufacturer, type, model and serial number.
- e) The specification of the **Metering Equipment**, including its accuracy class.
- f) **Current Transformers (CT)** manufacturer's certificates.
- g) **Voltage Transformer (VT)** manufacturer's certificates.
- h) The adjustment factors per **Meter**, including circuit losses to be applied.
- i) Detailed installation documentation.
- j) Date of installation.
- k) Date of commissioning, and
- l) Accuracy verification certificates.

MTC 5.1.2 The **System Operators** and **Non-WAPP Grid Operators** shall be obligated to share the **Metering Information** to the **SMO** for the permanent record keeping.

MTC 5.1.3 The **SMO** shall outline the guidelines and procedures to ensure up to date record keeping.

MTC 5.2 Main and Check Metering

MTC 5.2.1 The **Main Meter** and the **Check Meter** shall be of different makes and shall be of identical accuracy class. The **Main Meter** and **Check Meter** installations for interconnections shall be at the same voltage level.

MTC 5.2.2 The **Main Meter** and the **Check Meter** shall be connected to and operate from separate **CT** and **VT** windings. The operation of the **Main Meter** and the **Check Meter** shall be independent of each other to avoid simultaneous defect of both **Meters**.

MTC 5.2.3 Continuous **Main Meter** and **Check Meter** reading services shall be provided at all **Commercial Metering Points**.

MTC 5.2.4 **CT** and **VT** windings and cables connecting such windings to both **Main Meters** and **Check Meters** shall be dedicated for such purposes and such cables and connections shall be securely sealed.

MTC 5.3 Measurement Parameters

MTC 5.3.1 For each **Commercial Metering Point**, the **Metering Equipment** for the **Main Meter** and the **Check Meter** shall separately be capable of measuring the following parameters in both import and export directions: MW, MVAR, MWh and MVARh. Data shall be provided by the **Transmission Operator** to the relevant **System Operators** and the **SMO** in line with the relevant procedures and requirements.

MTC 5.3.2 The data provided by the **Transmission Operator** shall be available with a time resolution of five (5) minutes.

MTC 5.3.3 All **Metering Equipment** shall comply with the provisions set out in the **Metering Code**. The provisions in the **Metering Code** may be revised from time to time, in accordance with the provisions set out in the **General Conditions**, to take account of changing technologies or new requirements of the electricity industry.

MTC 5.3.4 A **CT** shall comply with the IEC standards specified in Table 1 (row 3) of Annex A. A **VT** shall comply with the IEC standards specified in Table 1 (row 4) of Annex A. Where a combined unit measurement transformer (**VT & CT**) is provided the “Tests for Accuracy” covering mutual influence effects shall be met as per the standards in Table 1 (row 5) of Annex A.

MTC 5.3.5 Where a combined unit measurement transformer (**VT** and **CT**) is provided, the “Tests for Accuracy” in the combined **CT/VT** covering mutual influence effects shall be met.

MTC 5.3.6 The **Meters'** cumulative registers shall not rollover more than once within a year of operation. The **SMO** shall provide a rollover procedure for this purpose.

MTC 5.3.7 In addition to the parameters measured in MTC 5.3.1, additional power quality parameters may be obtained either from the **Main Meter** and the **Check Meter** or from separate power quality **Metering Systems**. Such additional parameters may be requested within the framework of either a **Bilateral Data Exchange** or a **Multilateral Data Exchange**.

MTC 6. METERING EQUIPMENT ACCURACY AND ERROR LIMITS

MTC 6.1 Conformity

MTC 6.1.1 The accuracy of the distinct items of **Metering Equipment** shall conform to the relevant IEC standards or equivalent national standards mutually agreed between the concerned **Transmission Operators**. The accuracy limits set out in the **Metering Code** shall be applied after adjustments have been made to the **Metering Equipment** for compensation of the introduction of any errors due to any secondary equipment and connections. The accuracy of **Meters** shall be verified by an independent accredited agency approved by the **SMO** for this purpose. The agency shall provide an accuracy verification certificate with an indication of its validity expiry date.

MTC 6.2 Voltage Transformers (VT)

MTC 6.2.1 **VTs** shall have a minimum acceptable class of at least 0.2 compatible with standards referred to in MTC 5.3.4, and comprise three (3) single phase units, each of which shall comply, at a minimum, with the provisions of the referenced **VT** Standard.

MTC 6.3 Current Transformers (CT)

MTC 6.3.1 The **CTs** shall have a minimum acceptable class of at least 0.2 compatible with standards referred to in MTC 5.3.4 and comprise three (3) units for a three-phase set, each of which shall comply, at a minimum, with the provisions of the referenced **CT** standard.

MTC 6.4 Meters

MTC 6.4.1 **Meters** shall be of the three-element type independent for each phase, be rated as appropriate, comply with IEC Standards as per Table 1 (rows 1 and 2) of Annex A, and shall be of the accuracy class of at least 0.2.

MTC 6.4.2 In addition to the requirements of the meter standard', the **Meters** shall measure and locally display at least the MW, MWh, MVar, MVarh, and cumulative energy exchange. Additional features in support of the **Codes of Practice**, maintenance records, and power quality monitoring are desirable.

MTC 6.4.3 **Meters** shall be digital and shall separately measure and store all parameters bidirectionally and per phase.

MTC 6.4.4 The **Meters** shall, as far as practicable, conform to industry practice for rack-mounted meters, allowing for automatic **CT** shorting (“plug and play test blocks”) following a **Meter** removal.

MTC 6.4.5 The **Main Meter** and the **Check Meter** shall satisfy all requirements provided under MTC 5.2.

MTC 6.4.6 A cumulative register of the parameters measured shall be available on the internal storage facilities of the digital **Meters** for a minimum of six (6) months with five (5) minute interval recorded values. The loss of auxiliary supply to the **Metering Equipment** shall not erase these registers.

MTC 6.4.7 The registers in both the **Main Meter** and the **Check Meter** shall be readable by the **System Operator’s Automated Meter Reading System (AMR)** via the **WAPP Communication Network**. The minimum dataset from the **AMR** shall be shared in real-time with **the SMO** in accordance with the relevant procedures and requirements.

MTC 6.4.8 It is desirable that the **System Operator’s SCADA** shall read the **Meters’** registers and the additional **Information** be shared either bilaterally or multilaterally from the **System Operator’s AMR** or **SCADA**.

MTC 6.4.9 ***Compensation for Instrument Transformer Error***

MTC 6.4.9.1 All **Meter** installations shall be compensated for the individual errors of their associated instrument transformers and the leads to/from the **Meters**.

MTC 6.4.9.2 The compensation calculations, and the values applied to the **Meters** shall be recorded by the **Transmission Operator** and shall be made available to the **SMO**, along with the latest **Meter** and **Instrument Transformer** test certificates obtained at the time of commissioning, during normal operational activities and in case of any abnormality.

MTC 6.4.9.3 The **Instrument Transformer** error compensations shall be made directly in the **Meter** by either:

- a) A single calculated error or ‘offset’ which is a single error programmed into the **Meter** which is applied internally at defined test points on the error curve; or
- b) A series of calculated errors programmed into the **Meter** for each test point on the error curve and applied as such by the **Meter**.

MTC 6.4.9.4 Where the **Commercial Metering Point** and the **DMP** do not coincide, the **Metering System** shall be deemed non-compliant with the **Metering Code**. However, where justified and approved in line with the **General Conditions**, a dispensation may be granted, subject

to the submission and application of compensation for power transformer and/or line losses to ensure compliance with the overall accuracy requirements at the **DMP**.

MTC 6.4.9.5 The compensation may be achieved either within the **Metering Equipment** or by software within the **Data Exchange** system.

MTC 7. INSPECTION, TESTING AND ACCURACY VERIFICATION

MTC 7.1 Commissioning

MTC 7.1.1 All new **Meters** shall undergo relevant certification tests, and initial accuracy verification of **Meters** shall be performed in a recognized test facility. These tests shall be performed in accordance with the relevant IEC standards as per Table 1 (row 6) of Annex A and shall confirm that the **Meter** accuracy is within the limits stated in MTC 6.4.1 of the **Metering Code**. A unique identifiable accuracy verification record shall be provided for a **Meter** before the connection is commissioned.

MTC 7.1.2 **VTs** and **CTs** shall be verified in accordance with the relevant IEC standards prior to installation at the **Commercial Metering Point**. The **Transmission Operator** shall provide the manufacturers' test certificates for **CTs**, **VTs**, **Meters** and individual programmed compensations in line with the requirements for the **Metering Database**.

MTC 7.1.3 The commissioning shall cover the **Metering** system and the verification of data collection from both the **Main Meter** and the **Check Meter** at the **Defined Metering Points (DMPs)**.

MTC 7.1.4 The commissioning tests shall be conducted for both directions of power flow to the satisfaction of both the **Transmission Operators** and the **System Operators** involved in each **Interchange Point**.

MTC 7.2 Periodic Activities

MTC 7.2.1 The **Transmission Operator**, as owner of the **Metering Equipment**, shall be responsible to undertake accuracy verification testing upon request by the **SMO** or any relevant **System Operator**. Particularly, the **Transmission Operators** shall:

- a) conduct routine accuracy verification of the **Metering Equipment** every three (3) years, and
- b) check the connections for the **CTs** and **VTs** every five (5) years.

MTC 7.2.2 The accuracy of each **Meters** shall be verified by an accredited laboratory either once every ten (10) years from the date of commissioning, or upon the expiration of the manufacturer-issued accuracy certificate, whichever occurs earlier.

MTC 7.2.3 Where the **Meters** have been adjusted to compensate for errors in the **CTs** and **VTs**, those **CTs**, **VTs**, and their connections, shall be checked at the same periodicity as the **Meters**.

MTC 7.2.4 Where, following a test, the accuracy of the **Metering Equipment** is found not to comply with the requirements of this **Metering Code**, the **Transmission Operator** shall take such measures necessary to ensure compliance of the **Metering Equipment**.

MTC 7.2.5 The **Transmission Operator**, as owner of the **Metering Equipment**, shall bear the cost of routine testing of the **Metering Equipment**.

MTC 7.2.6 The cost of unscheduled accuracy verification tests shall be borne by the requesting **Party**, unless the test shows the accuracy of the **Metering Equipment** does not comply with the requirements of the **Metering Code**; in which case the cost of the tests shall be borne by the responsible **Transmission Operator**.

MTC 7.2.7 **Transmission Operators** and relevant **System Operators** shall carry out a physical inspection and on-site reading of all **Metering Equipment** at **DMPs** at least once every six (6) months to reconcile cumulative register readings on-site with remotely collected data. Physical checks shall be conducted at the same time to identify missing seals or damage or any other issues of concern as may be identified.

MTC 7.2.8 Where a **Metering Equipment** component is found to be non-compliant with the **Metering Code** and the **General Conditions**, the concerned **Transmission Operator** shall promptly inform the concerned **System Operator** or **Non-WAPP Grid Operator** and any party affected of the failure or the non-compliance. Such notification shall include the plans by the concerned **Transmission Operator** to restore the **Metering Equipment** to service in compliance with the **Metering Code**.

MTC 7.2.9 The **SMO** shall be notified of any **Metering Equipment**'s non-compliance. In cooperation with the affected **System Operators**, the **SMO** shall assess the duration of the non-compliant period. when the **Metering Equipment** has been faulty or non-compliant. During this period, recorded data from the **Check Meter** shall be used.

MTC 7.3 Data Collection

MTC 7.3.1 The **System Operators** shall collect all data recorded by the **Metering Equipment** at **DMPs** by remote or on-site manual interrogation, in accordance with the **Metering Code**. The **System Operator** shall undertake the on-site manual interrogation in collaboration with the **Transmission Operator**.

MTC 7.3.2 For the purposes of remote interrogation, the **System Operator** responsible may use its own data communications network. In the absence of this, the **System Operator** shall enter into, manage, and monitor contracts to provide for the maintenance of all data links by which data is passed to the **System Operator** and to the **SMO** in line with the provisions in the relevant sections of each **Code** concerning **Data Exchange**.

MTC 7.3.3 In the event of the absence of a communication link or any fault or failure on such communication links or any error or omission in such data, the **System Operator**, together with the concerned **Transmission Operator**, shall, where possible, retrieve such data by on-site manual interrogation.

MTC 7.4 Security

MTC 7.4.1 Each **Transmission Operator**, as the owner of the **Metering Equipment** at the **DMPs**, shall ensure that the **Meter** itself is sealed and that any links and secondary circuits of the **Metering Equipment** are sealed, where practically possible. The seals shall only be placed and broken in the presence of representatives of the relevant **System Operators** and the responsible **Transmission Operators**, unless expressly agreed otherwise by the **Parties** involved.

MTC 8. DISPUTES

MTC 8.1.1 **Disputes** concerning this **Metering Code** shall be dealt with by following the procedures set out in the **General Conditions**, aligned with the **ERERA Dispute** resolution procedures.

MTC 9. METERING DATA CONFIDENTIALITY

MTC 9.1.1 **Metering Data** may contain commercially sensitive and **Confidential Information**. Accordingly, appropriate measures shall be taken to ensure that the **Metering Data** cannot be divulged, or obtained, by third parties without due authorisation.

MTC 9.1.2 The **SMO** shall develop appropriate policies on **Metering Data** sharing, for the approval of **ERERA**.

MTC 10. OPERATIONAL METERING

MTC 10.1.1 Operational **Metering Equipment** is required to support real-time operation of the electricity market. Since operational requirements differ from the **Metering** requirements at the **Interchange Point**, the operational **Metering System** does not necessarily have the same requirements for accuracy of measurement.

MTC 10.1.2 Timely operational **Metering Data** is, however, critical for the efficient, safe and timely operation of the **WAPP Power System**.

MTC 10.1.3 **System Operators** are encouraged to bilaterally agree on the types of **Operational Data** required for **Real-Time Data Exchange** and shall ensure that appropriate systems are in place to support this **Operational Data** exchange.

ANNEX A – Application of Standards

The foundation of the **Metering Code** is based on internationally agreed and applied standards.

It is advised to ensure that the accuracy is the best possible at the time of selection, if industry solutions are exceeding the standards.

The revisions and updates of any standards or **Codes of Practice** shall apply on a forward-looking basis only and shall not require changes to existing commissioned solutions.

Any change of standard or **Codes of Practice**, as may be adopted by **WAPP**, may lead to the consideration of adaptations, changes and updates of the existing **Metering Equipment** as part of the scheduled and normal operational and maintenance life cycles, based on mutually agreed economic and operational merits.

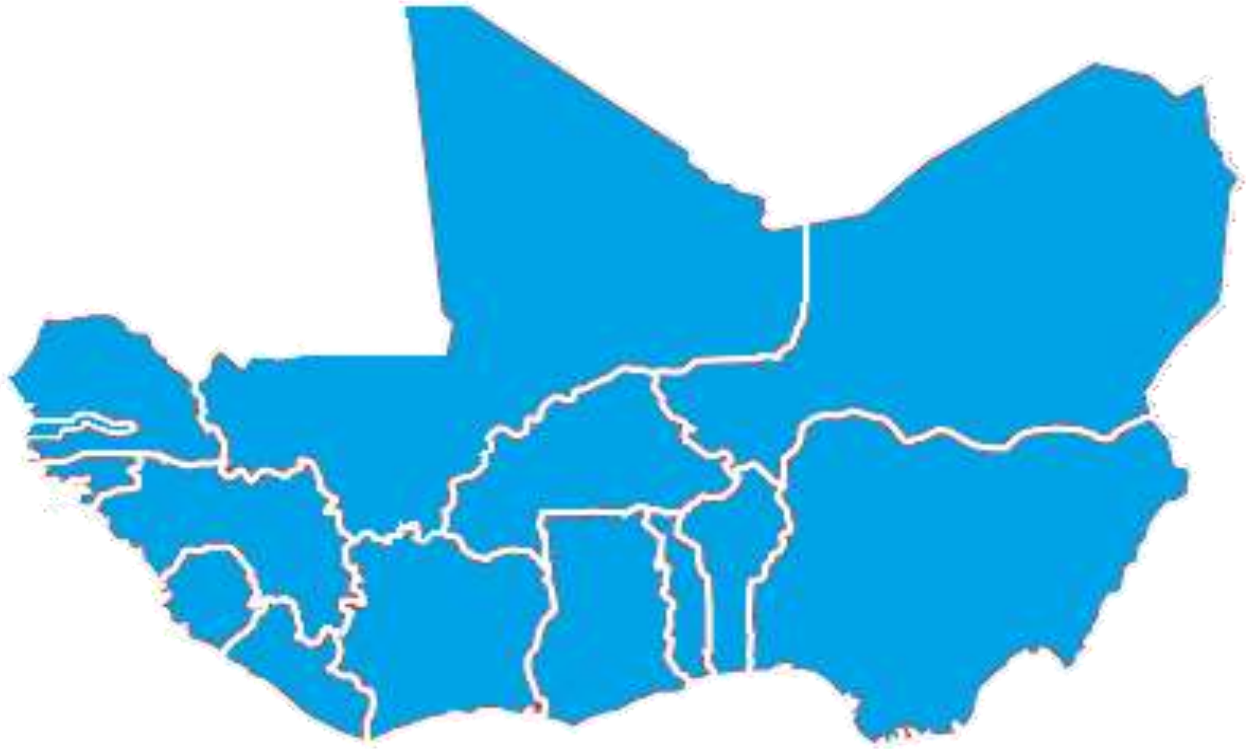
The International standards to be adopted in the **Metering Code** are provided in Table 1.

Where change in the international standards, or subject to agreement in **WAPP**, the latest updated references in force in the **REM** shall prevail on the contents of the table 1 below:

Table 1. International standards to be adopted in the Metering Code

Row.	Ref. in the Code	Reference international standard
1	Active energy	IEC 62053-22:2020, or later, as legally approved.
2	Reactive energy	IEC 62053-24:2020, or later, as legally approved.
3	CT Standard	IEC 61869 series, or later, as legally approved.
4	VT Standard	IEC 61869 series, or later, as legally approved.
5	Combined CT/VT	IEC 61869 series, or later, as legally approved.
6	Certification tests for meters	IEC 62052-11, or later, as legally approved.

REGIONAL ELECTRICITY MARKET CODES OF WEST AFRICA



OpTC – OPERATORS TRAINING CODE

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OPTC 1. PURPOSE AND SCOPE OF TRAINING

OpTC 1.1 Purpose of the Operators Training Code

- OpTC 1.1.1 This **Operators Training Code** relates to the training elements that the **Grid Operator** and **SMO**'s personnel operating the **Power System** shall receive, in order to properly handle the complexity of the interconnected **WAPP Power System**.
- OpTC 1.1.2 The beneficiaries of the training activities are those persons in charge of **Long-Term Planning, Operational Planning**, market operations, real time operation including post-event analysis, at any responsibility level within the **Grid Operator** and the **SMO**.
- OpTC 1.1.3 In this **Operators Training Code**, the **Grid Operator**'s personnel under training are referred to as trainees.
- OpTC 1.1.4 The **Entities** responsible for providing training are **WAPP, SMO, Grid Operators**, and any other **Entity** that are delegated by proxy to take decisions on the aforementioned activities reported in article OpTC 1.1.2.
- OpTC 1.1.5 In this **Operators Training Code**, the **Entities** providing training are referred to as **Training Entities** and the physical persons providing training are referred to as trainers.
- OpTC 1.1.6 Training shall be a prerequisite for the certification of the competence of personnel to operate the **Power System**. Certification programs and processes for system and market operations shall be developed and enforced by **WAPP**.

OpTC 1.2 Orientation on the Training Content

- OpTC 1.2.1 The training shall deal with:
- a) technical and practical matters related to the system and the market;
 - b) essential background knowledge, that are easily adaptable to fit set objectives;
 - c) knowledge really needed and directly applicable;
 - d) essential activities tailored to the needs, duties and professional level of the trainees;
 - e) The functioning and management of the **Regional Electricity Market (REM)**.

OpTC 1.3 Training Management Guidelines

- OpTC 1.3.1 The training activity outlined in this **Operators Training Code** shall be part of a broader training program to be carried out by **the SMO** and each **Grid Operator**.

- OpTC 1.3.2 The **Training Entities** shall be responsible and in charge of:
- a) Identifying from the relevant departments, the training needs to be addressed.
 - b) Enquiring from the relevant departments, the level of skill gaps of the trainees and their training needs.
 - c) Organizing and performing the whole training activity.
- OpTC 1.3.3 The training activity shall comply with the following requisites:
- a) Be planned with appropriate time schedule.
 - b) Be traceable: traceability implies that the **Training Entity** shall keep a register where hours and topics are duly recorded.
 - c) Make systematically available the feedback on the outcome of the training provided. This means that a trainee shall be required to undertake a test at the end of the training cycle.
 - d) Issue the appropriate certification. To this end all training materials used for the training of a trainee must be accessible and validated for certification by the internal or external certification body, if applicable, at the end of the internal training.
- OpTC 1.3.4 The training plans shall be based on:
- a) The harmonization and consistency with the current active programs as agreed between **WAPP** and the **Grid Operators**.
 - b) The lead role of **WAPP** in matters concerning the **REM Codes**, namely the interconnected **Operation** of the **WAPP Power System** and the development of the **Cross-Border Interconnections**.
 - c) The lead role of the **Grid Operators** as far as the control of the **LFC Area** under their responsibility is concerned.
 - d) The *System Operator Certification Program* and Market Operator Certification Program adopted by **WAPP** and the **Grid Operators**, aiming at ranking of skills.

OpTC 1.4 Training Arrangements

- OpTC 1.4.1 According to the topic and the learning needs of the trainees, the training activity shall be organized as:
- a) Continuous training.
 - b) On demand training.
 - c) Training on the job.
 - d) Off-line training.

- OpTC 1.4.2 Continuous training shall be guaranteed to ensure the adequacy of the personnel over time. For the continuous training, the time between two training cycles shall not exceed two (2) years.
- OpTC 1.4.3 On demand training shall be provided in the event the operating procedures change (e.g. the **SCADA**, the **EMS** applications), the general **Functional Operation** environment change (e.g. new interconnections), or the personnel shows lack of confidence on some matters.
- OpTC 1.4.4 Training on the job shall be provided by the **Grid Operator's** personnel in charge of the same job or the head of the trainee. Training on the job is mandatory:
- a) for newly recruited personnel of **Grid Operators** before the assignment of operational duties.
 - b) for the cooperation initiatives as per OpTC 5.
- OpTC 1.4.5 Off-line training shall be organized in regular workshops and provided mainly by senior experts of the **Grid Operator's** personnel. External experts or facilitators are recommended when:
- a) knowledge transfer is needed from equipment manufacturers;
 - b) their experiences are considered useful to enhancing performance of the personnel;
 - c) the focus on lesson learned from **Grid** events are beneficial for the mindset of the personnel.

OpTC 1.5 Trainer Requirements

- OpTC 1.5.1 Trainers shall be selected by the relevant **Training Entity** based on the trainers' experience, academic qualification, and skill necessary for the nature of the training to be provided.
- OpTC 1.5.2 Trainers selected from **Grid Operator's** internal personnel shall be preferred for practical training on internal procedures. The internal trainers should have been trained on teaching techniques to enhance their effectiveness and clarity.
- OpTC 1.5.3 External trainers shall be selected preferably from experts with proven experience in activities of the **Grid Operator** or **Grid Operators'** association, **WAPP**, **SMO**, **ERERA**, vendors, consultant, centres of excellence and academia.
- OpTC 1.5.4 Dedicated memorandum of understanding may be signed with universities on specific topics that can be considered innovative or not covered by the **Training Entity's** skills.

OpTC 1.5.5 ***Training of Trainers***

- OpTC 1.5.5.1 Trainers shall engage in continuous professional development activities to enhance and update their knowledge of advancements in **Power system** operation.
- OpTC 1.5.5.2 A minimum number of hours for annual professional development shall be established by **WAPP**, and trainers are required to meet this requirement.
- OpTC 1.5.5.3 Trainers shall undergo periodic updates on changes in **Power System** technologies, regulations, and **Good Utility Practice**.
- OpTC 1.5.5.4 The frequency and content of these updates shall be determined by **ERERA** and communicated to trainers in a timely manner.
- OpTC 1.5.5.5 A periodic assessment of trainer competence shall be conducted by **WAPP** to evaluate their effectiveness in delivering training content.
- OpTC 1.5.5.6 Trainers shall maintain records of their professional development activities, including details of courses attended, certifications obtained, and any other relevant training initiatives.

OpTC 1.6 The logistic organization

- OpTC 1.6.1 **Training Entities** shall provide the logistics and strive to create the best learning conditions for the trainees.
- OpTC 1.6.2 **Training Entities** shall relieve the burden of everyday activities of the trainees. Such activities never should interfere with the tuition sessions and vice versa.
- OpTC 1.6.3 The training activity shall be delivered through in-person or remote sessions.
- OpTC 1.6.4 **Training Entities** shall provide:
- a) Training programs, skills required, duration of the sessions, topics, objectives, difficulty level, beneficiaries and any other detail required to design the training pathways.
 - b) Tutorial material associated with the topics to be handled.
 - c) Training programs should conform to this **Operators Training Code**.

OpTC 1.7 Administrative aspects

- OpTC 1.7.1 Costs for training shall be thoroughly recorded. **ERERA** and the **NRAs** shall admit such costs as eligible costs.

OPTC 2. TRAINING PROGRAMS ON BASICS OF POWER SYSTEM

OpTC 2.1 Goal, Topics, and Targets

OpTC 2.1.1 The goal of the training in this OpTC 2 is to create awareness to develop a common language and common understanding about the current challenges of the **Electricity Supply Industry**.

OpTC 2.1.2 The training topics should include:

- a) Updates on the latest technological advancement in **Power System** (e.g. **PMU**, **FACTS**, dynamic thermal rating).
- b) Overview of the latest regulatory updates.
- c) Operational models of the interconnection.
- d) Planning challenges.
- e) Market models.
- f) **RESs** in the context of the energy transition.
- g) Funding mechanisms.

OpTC 2.1.3 Target audience for this training program shall include:

- a) Middle management of the **Grid Operator** company.
- b) All personnel involved in **Functional Operation**.

OPTC 3. TRAINING PROGRAMS ON THE REM CODES

OpTC 3.1 Goal, Topics, and Targets

OpTC 3.1.1 The goal of the training in this OpTC 2OpTC 3 is to share knowledge on the rights, duties and obligations deriving from the application of the **REM Codes**.

OpTC 3.1.2 The training topics shall be the contents of the **REM Codes**.

OpTC 3.1.3 Target audience for this training program shall include:

- a) Management of **Grid Operators**.
- b) Legal personnel of **Grid Operators**.
- c) All personnel of the **Grid Operators** and the **SMO** involved in **Functional Operation**.

OPTC 4. TRAINING PROGRAMS ON SYSTEM OPERATION

OpTC 4.1 Objective

OpTC 4.1.1 The objective of the training in this OpTC 4 is to enhance the capacity and confidence of **Grid Operator's** personnel in charge of **Operational Planning** and real time **Functional Operation**.

OpTC 4.1.2 **Operator Training Simulator (OTS)** is recommended for sessions on practices and control. The **OTS** is a powerful tool to simulate the dynamic behaviour of the **Transmission System** and replicate the real control room environment. The recommended functional requirements are summarized as follows:

- a) Architecture that clearly separates the interface of the trainer from that of the trainee;
- b) A trainer interface with the capability to introduce predefined or customised **Contingencies** and malfunctions, including faults in power system protection and control schemes, to test trainee's responses under stress or abnormal conditions.
- c) replication of the real operational environment;
- d) interface with the **SCADA** system and ability to record and retrieve real operational events.
- e) Capability to store and replay training sessions to produce a lesson library.

OpTC 4.2 System Operation Topics

OpTC 4.2.1 The execution of **Operational Planning** and real-time **Functional Operation** tasks requires careful selection and training of the relevant personnel.

OpTC 4.2.2 The training programme for the system operation shall ensure the realisation of the following objectives:

- a) the personnel in charge of system operation is well qualified, psychologically capable, and thoroughly conversant with the principles and procedures of interconnected system operations.
- b) the personnel in charge of system operation has a thorough understanding of the basic principles of **Power system**. The power system consists of a variety of **Elements**, equipment and apparatus, hence thorough understanding of their characteristics and how these devices are integrated is essential.
- c) the personnel in charge of system operation demonstrates good communication skills, the ability to make prompt decisions, and capable of supervising others.

OpTC 4.2.3 The training shall consider:

- a) the knowledge and competencies required to apply policies;
- b) procedures, and requirements for normal, emergency, and restoration conditions;
- c) the **Regional Electricity Market Regulation (REMR)** requirements on system **Functional Operation** and related procedures.

OpTC 4.2.4 Topics shall include the following:

- a) Normal Operation
 - i. **Basics of power flows: Generation, Transmission**, transformers, **Load** characteristics and effect on the **Power System**, phase angle, reactors, capacitors, power flows, **HVDC Systems**, voltage regulation, causes of voltage deviations, generator excitation, transformer taps, reactive sources, line and cable switching, **Reserve**, dispatching techniques, **AGC, Area Control Error**, interchange control, inadvertent interchange, special operating programs.
 - ii. *Economic Operation*: short-term **Demand Forecast**, economic dispatch, operating guidelines and constraints and operating considerations.
 - iii. *System Protection*: basic protection relaying schemes, protection discrimination and sensitivity, protection coordination, interpretation of relay operation.
- b) Abnormal Operation
 - i. *Dynamic performance of the Power System*: transient stability, oscillations, causes of disturbances, **Special Protection Schemes**
 - ii. *Dynamic performance of equipment*: governor response, exciter response, automatic control (frequency relays, **AGC**, voltage control, generator and load tripping, system separation), line fault, frequency deviation, and Interchange deviation, voltage level, isolated system operation, **Functional Operation** in abnormal frequency and voltage deviations.
 - iii. *Power System Restoration*: **Black Start Capability**, generator start-up capabilities, and pick-up rates, system synchronization.
- c) Interconnected system operation
 - i. **SMO's operating criteria and guidelines**: philosophy of operation (e.g., economic dispatch, inadvertent cross-border exchange), benefits, obligations, responsibilities, authority.
 - ii. *Impacts on system performance*: frequency, interchanges, **Reserves**, mutual assistance.
 - iii. **REMR framework**.
- d) **Power System Control**
 - i. *Equipment*: human-machine interface, supervisory control, data acquisition, fall over and restart (master-slave switchover), uninterruptible power supplies.

- ii. *Theory and use of software application for **Normal Condition** and **Emergency Condition: System State** estimation, economic dispatch, **AGC**, unit commitment, load flow, **Contingency** analysis, interchange accounting, alternative control methods during equipment and software unavailability, and typical software applications.*

e) Mode of Communication

- i. *Power line carrier schemes (PLC)*
- ii. *Private microwave systems*
- iii. *Radio*
- iv. *Optical fiber*

f) Supervisory skills

- i. *Language (English and French)*
- ii. *Verbal communication*
- iii. *Decision making*
- iv. *Stress management*

OpTC 4.2.5 The training program shall consider an initial session for first accreditation, and a continuous program for constant updating. The roles of the **SMO** and the **Grid Operators** on the training programs and related certifications shall follow the criteria set in article OpTC 1.3.4.

OpTC 4.2.6 ***Initial training session***

OpTC 4.2.6.1 The aim of the initial training session is to prepare the **Grid Operator's** personnel to occupy the dispatcher position and it shall provide an adequate necessary level of professional knowledge in order to obtain the required qualifications. It shall be organized in three (3) parts:

- a) Off-line part: to provide a first level of competencies on the main topic categories concerning the **Power System** theory: basics of power flows, **Power System** components, management of **Power System** (normal operation, economic operation, abnormal operation, restoration, interconnected system operation), knowledge of operational tools, knowledge of the rules and procedures of the **REMR** on the **Functional Operation** matter.
- b) On the-job-part: to allow trainees to put in practice all the professional actions in real time operation, using appropriate tools, and guided by experienced personnel in the respective position.
- c) On the simulator part: to allow trainees to experience simulated normal and insecure situations.

OpTC 4.2.7 **Continuous training sessions**

OpTC 4.2.7.1 The main aim of the continuous program is to keep and extend the dispatchers' knowledge and competencies over time. It should reproduce the three (3) parts of the initial training course with some more elements gained by experience:

- a) Off-line part: to provide advanced knowledge on some specific topics, such as analysis of disturbances, recapitulation of important aspects of **Grid Operation** at the different **Operating Conditions**, changes in the **Power System**, information about new rules and procedures, human behaviour aspects.
- b) On the simulator part: to simulate situations with insecure and emergency **Scenarios**, complemented by the **Restoration** of the **Power System** after disturbances / black-outs.
- c) Stress management: to inform **Grid Operator's** personnel on methods to manage the stress.

OpTC 4.2.8 **Topics Related to the Electricity Market**

OpTC 4.2.8.1 The training on this topic aims at:

- a) enhancing awareness of dispatchers on the rights and duties of the **Grid Users** and the economic consequences of dispatching and other operation actions in general.
- b) Developing the dispatchers' knowledge of the **REMR**.

OpTC 4.3 **Target for System Operation Training**

OpTC 4.3.1 Target trainees of this program shall include all personnel involved in the **Functional Operation** and regulation.

OPTC 5. **TRAINING PROGRAMS ON INTERCONNECTED-GRID OPERATION**

OpTC 5.1 **Goal**

OpTC 5.1.1 The **SMO** shall foster the cooperation on **Grid Operator** training as the **Functional Operation** of the National **Transmission Systems** near international **Cross-border Interconnections** with bordering **Member States** is strongly influenced by the **Generation/Load** pattern and the topologies of the neighbouring **Power Systems**. Thus, it is essential to develop a framework for a regular joint training of control room operators focusing on specific situations for the most critical boundaries and involving mainly experienced operators.

OpTC 5.1.2 **Grid Operators** may sign bilateral or multilateral agreements of cooperation for joint training, in order to pursue common objectives on **Security of Operation** and improvement of procedures.

- OpTC 5.1.3 The **Grid Operator** training program should allow neighbouring **Grid Operators** to be aware of the peculiarities of the respective neighbouring **Power Systems** and the effectiveness of the coordinated **Remedial Actions** implemented across the borders under the various operating conditions (**Normal State**, **Alert State**, **Emergency State**, **Blackout State**, and **Restoration**).

OpTC 5.2 Interconnected Grid Operation Training Topics

- OpTC 5.2.1 Technical topics should focus on:
- a) Security assessment practices.
 - b) **TTC/NTC** calculation.
 - c) **Contingency** studies and **Remedial Actions**.
- OpTC 5.2.2 ***Training programs and modalities***
- OpTC 5.2.2.1 Cross visits shall be taken as a good opportunity for dispatchers to know each other on a personal level and introduce a more collaborative atmosphere between the dispatchers, and to provide a global overview of the **Transmission Systems** of the **Member States**.
- OpTC 5.2.2.2 Joint workshops are recommended to provide the same set of information to all involved **Grid Operators** with a view to better understanding the problems of the neighbouring **Power Systems** and the content of existing procedures in normal and abnormal **System States**.
- OpTC 5.2.2.3 On-shift cross periods may be used as a mechanism to improve in-depth understanding and interpersonal communication between neighbouring **Grid Operator**'s dispatchers and to reinforce the knowledge level of the **Power Systems** of the neighbouring **Member States**.

OpTC 5.3 Target for Interconnected Grid Operation Training

- OpTC 5.3.1 Target trainees of this program shall include all personnel involved in real time **Functional Operation**.

OPTC 6. TRAINING PROGRAMS ON LONG TERM PLANNING

OpTC 6.1 Objective

- OpTC 6.1.1 As the **Long-Term Planning** activity requires competencies in **Power Systems**, electrical engineering, economics, and mathematics, the **Long-Term Planning** training shall be based on these topics.

OpTC 6.2 Long Term Planning Training Topics

OpTC 6.2.1 Long Term Planning Training topics should focus on:

- a) Theoretical reference on probability, reliability, forecast, to align theoretical background to application.
- b) Computer methods in **Long-Term Planning** (e.g. Monte Carlo Method), to give the perception of pros and cons of various methods and their intrinsic limitations.
- c) Databases structures and management, to acquire knowledge in the technicalities behind the data needed for simulations, and to better select **ICT** personnel and specialists dedicated to the design and the maintenance of the database.
- d) **Planning Code**, to sensitize those responsible for the **Long-Term Planning** about obligations and basic choices.
- e) Structure of the **WAPP Power System** and related peculiarities, to better share the issues in common within the **Member States**.
- f) Challenges, determinants, and priorities of the **WAPP Power System**, to build up scenarios, decide **KPIs**, and agree on objectives of the **Master Plans**.
- g) Operation practices, to recall the constraints that the good **Operation** poses to the **Long-Term Planning** and to guarantee consistency between **Long-Term Planning** and **Functional Operation** regarding security and adequacy levels
- h) Training on the tools adopted for market and grid simulations, to speed up the application, make easier the input-output of the planning tools, and check results for validation.
- i) **Grid Elements** and associated standard costs (for cost benefit analysis), to have a uniform approach to the costs and make comparable the results of the cost benefit analysis.

OpTC 6.3 Target for Long Term Planning Training

OpTC 6.3.1 Target trainees for this program shall be:

- a) Management of **Grid Operators**.
- b) All personnel of the **Grid Operators** and the **SMO** involved in the market operation.