GREATER MEKONG SYSTEM REGIONAL GRID CODE

Market Code (draft)

8 of 10 Code Documents

Version 0.2

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Version control

Document #	Title: **GMS Regional Grid Code** **Market Code**	Print Date: **[Date]**
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***Note:** A section titled "ANNEX: Code – History of Comments" is attached to each Code. It provides a log of every comment and subsequent consideration taken on the Code.*

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1. Introduction

(1) This code contains a set of operational requirements for the GMS Market including *Capacity Allocation and Congestion Management, Forward Capacity Allocation,* and *Electricity Balancing*.

(2) The *Capacity Allocation and Congestion Management* Code sets out non-discriminatory rules for access conditions to the network for cross- border exchanges in electricity and, in particular, rules on capacity allocation and congestion management for interconnections and transmission systems affecting cross-border electricity flows.

(3) To implement bilateral trading, day ahead and intraday markets, the available cross-border capacity needs to be calculated in a coordinated manner by *RPCC*. For this purpose, *RPCC* should establish a common grid model including estimates on generation, load and network status for each hour. The available capacity should normally be calculated according to the so-called flow-based calculation method, a method that takes into account that electricity can flow via different paths and optimizes the available capacity in highly interdependent grids. Each TSO of the interconnected system is required to prepare an individual grid model of its system and send it to *RPCC* for merging them into a common grid model. The individual grid models should include information from generation and load units.

(4) The Electricity Balancing Code establishes a GMS-wide set of technical, operational and market rules to govern the functioning of electricity balancing arrangements. It sets out rules for the procurement of balancing capacity, the activation of balancing energy and the financial settlement of balancing energy. The Electricity Balancing Code provides balancing and imbalance rules for the cases with and without a day-ahead market / intraday market and with and without a balancing market.

(5) This code was based on codes and policies stated in EU Commission Regulations 2015/1222, 2016/1719, ENTSO-e Policy 4 v2.4 and draft Balancing Code, accessed November 2017, and adapted for the GMS Interconnected Network.

2. Capacity Allocation, Forward Capacity Allocation and Congestion Management Code

2.1 Physical Transmission Rights (PTR)

(1) Transmission capacity shall be allocated hourly to market participants with approved bilateral contracts in the form of physical transmission rights (PTR).

(2) Transmission capacity shall be first allocated in the order of approval of bilateral contracts, that is the oldest bilateral contracts are the first to be allocated transmission capacity.

(3) Bilateral contracts shall not be approved should there not be sufficient transmission capacity.

(4) Should the transmission capacity be reduced due to unforeseen circumstances, the last approved bilateral contracts shall be cancelled until sufficient capacity is available for safe and secure operation of the GMS interconnection.

2.2 Financial transmission rights (FTR)

(1) Physical transmission rights can be converted into financial transmission rights when and if market rules allow this.

(2) *RPCC* shall be responsible for the auctioning of transmission capacity when and if market rules allow this.

2.3 Capacity calculation time-frames

(1) *RPCC* shall calculate cross-zonal capacity for at least the following time-frames:

(a) Long term bilateral trades which are trades that are longer than a year up to 20 years ahead;

(b) Rolling year ahead for short term bilateral trading market;

(c) day-ahead, for the day-ahead market (future); and

(d) intraday, for the intraday market (future).

(2) Long term bilateral trades capacity calculation shall be calculated on an ad hoc basis by *RPCC* when requests are received from participants.

(3) Market participants must confirm bilateral contracts every week for the following week-ahead by 12:00 on Wednesday. Bilateral contracts not confirmed will be deemed to have been terminated and will lose the associated transmission right pursuant to the Use it or Lose it principle.

(4) For rolling year ahead, the capacity calculation shall be updated each time there is a new short term bilateral trade approved by *RPCC* and at least weekly based on the latest available information. The weekly information update shall be before 12:00 market time every Thursday.

(5) *RPCC* shall annually calculate minimum monthly ATC information specific to each market participant for the 20 year ahead forecast.

2.4 Generation and load data provision methodology

(1) *RPCC* shall in conjunction with the *TSOs* develop a methodology for the delivery of the generation and load data required to establish the common grid mode

(2) The generation and load data provision methodology shall specify which generation units and loads are required to provide information to their respective *TSOs* for the purposes of capacity calculation.

(3) The proposal for a generation and load data provision methodology shall specify the information to be provided by generation units and loads to *TSOs*. The information shall at least include the following:

(a) information related to their technical characteristics;

(b) information related to the availability of generation units and loads;

(c) information related to the schedules of generation units;

(d) relevant available information relating to how generation units will be dispatched.

(4) The methodology shall specify the deadlines applicable to generation units and loads for providing the information referred to in paragraph (3).

2.5 Transmission capacity calculation methodology

(1) The Total Transfer Capacity methodology shall include at least the following items for each capacity calculation time-frame:

(a) methodologies for preparing the inputs to capacity calculation, which shall include the following parameters:

(i) a methodology for determining the reliability margin;

(ii) the methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints;

(iii) the methodology for determining the generation shift keys as defined in Paragraph 2.5.4;

(2) The capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

(3) The transmission capacity calculation shall be performed annually for the following two calendar years and shall be published by 30 November of the preceding calendar year.

2.5.1 Transmission reliability margin methodology

(1) *RPCC* has to determine the Transmission reliability margin (TRM) methodology which is taken into account in the capacity assessment process.

(2) The TRM is an allowance made in the calculation of capacity on the interconnectors between *TSOs* to allow for deviations between power flows in actual system operation and those calculated in simulations, and also to allow for errors in the calculation process. The TRM shall consider at least the following:

(a) The TRM must at least cater for primary frequency reserve activation of the *TSOs*;

(b) The TRM shall be at least 0.5% of Total Transfer Capability to cover measurement errors;

(c) The TRM shall consider historical power system flow errors and uncertainties

2.5.2 Net Transfer Capacity (NTC) and Available Transfer Capacity (ATC)

(1) Net Transfer Capacity (NTC) and Available Transfer Capacity (ATC) are calculated as follows:

NTC (Net Transfer Capacity) = BCE + ΔE – TRM

Where:

BCE = Base Case Exchange (Scheduled Exchange)

ΔE = Maximum Shift of generation that can be assigned to control areas involved in the interconnection preventing any violation from appearing with n or (n-1) criterion.
TRM = Transmission Reliability Margin

ATC (available transfer capacity) = NTC – AAC
where:
AAC = already allocated capacity

2.5.3 ATC calculation procedure

(1) *RPCC* shall perform an iterative and load flow-based procedure to determine ATC

(2) The input data sets ("Wet / Dry Season") are the GMS reference cases based on the GMS snapshot that have to follow the following rules:

(a) For all generation nodes that are to be considered for the NTC determination, the minimum and maximum output power must be indicated. Generators out of operation in the base case must also be included, with their corresponding limits, so that they could be switched on if necessary during NTC determination.

(b) In cases where a node of the transmission network is linked by a transformer to a lower voltage radial network with load and generation, the load and the generation can be summed up separately and indicated in the node of the transmission network (thus the aggregated generation of the lower voltage network can be used for the NTC determination). In this case the summed minimum and the maximum of the generation power must be indicated. In the case of meshed underlying networks, that procedure is not admissible; such networks have to be explicitly modeled.

(c) Pump storage stations that also have to be considered for the NTC determination can be defined by the indication of the minimum and maximum power limits.

(3) Generators that take part in the NTC determination must be characterized by their minimum and maximum power limits. It is possible to choose a limited number of generators to perform the NTC calculation manually, especially when there are many generators.

(4) The chosen generators are used for the NTC determination in the following way: in the area of one *TSO* (generators i=1,n) the generators' active power is increased and in the area of the other *TSO* (generators j=1,m) the generators' active power is decreased by the same value simultaneously.

(5) That shift shall be accomplished as follows:

(6) Method A (preferred method):

(a) All chosen injections are modified proportionally to the remaining available capacity.

$$P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i^{max} - P_i}{\sum_n (P_i^{max} - P_i)}$$

$$P_{new}^{dec} = P_i + \Delta E \cdot \frac{P_i^{min} - P_i}{\sum_n (P_i^{min} - P_i)}$$

$$\text{additional condition: } |\Delta E| \leq |\sum (Pmax - Pi)|$$

$$\text{additional condition}: \quad |\Delta E| \leq \left|\sum(Pmin - Pi)\right|$$

where

P_i : Actual active power generation (MW)

P_{new}^{inc} : New increased injection, in next iteration it will be P_i

P_{new}^{dec} : New decreased injection, in next iteration it will be P_i

ΔE : Shift generation, negative for increasing and positive for decreasing

P_i^{max} : Maximum permissible generation (MW)

P_i^{min} : Minimum permissible generation (MW)

(b) **Advantage:** generation over-utilization is impossible and generation capacities are reached simultaneously. It is also ensured that the evacuating lines are not overloaded because their capacity was based on the maximal power evacuation.

(c) This method should be used by *TSOs* in the normal case, because it respects the physical limits while operating a transmission grid. The last value of ΔE^{max} is determined when all generators or any network element reached its operation limits.

(7) Method B:

(a) This method shall only be used in emergency cases if the indication of the generation limits are missing or as a further calculation after the capacities used in method A have all been reached.

(b) All chosen injections are modified proportionally to the current generation:

$$P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}$$

$$P_{new}^{dec} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}$$

Remark: delta E has got a different sign in the decrement case from the increment case (see also method C).

(c) In this method, the generation limits are not considered; this can lead to an over-utilization and thus to unrealistic NTC results. The method B indicates a theoretical NTC value of the transmission grid without taking the physical limits of production into consideration.

(8) Method C:

(a) The chosen injections are modified proportionally according to a merit order with indications of the ranking after each injection taking the maximal and minimal production into account.

2.5.4 Generation shift computation (ΔEmax)

(1) After the generations and the shift method for the NTC determination have been chosen, ΔE is increased iteratively until a relevant constraint is violated.

(2) After each iteration step, the n-1 security must be checked in the GMS transmission network; *RPCC* shall in conjunction with the *TSOs* decide which elements are to be considered in the n-1 security analysis.

(3) During the NTC determination, the transformer taps and the reactive injections of PQ nodes are not changed. The change of losses caused by the load flow shift is compensated in the slack node.

2.6 Long-term capacity calculation

(1) Long-term capacity shall be calculated the for the peak demand for every 5th year in the next 20 years;

(2) *RPCC* shall determine if it is necessary to check long-term capacity in other periods of the 5th year on intermediate years;

 (a) *RPCC* shall publish the minimum transmission available capacity for these additional studies noting any additional limitations;

(3) The uncertainty associated with long-term capacity calculation time frames shall be taken into account;

(4) The approved GMS long-term generation and transmission expansion plan shall be used.

2.7 Available transmission capacity publishing

(1) *RPCC* shall publish the ATC information specific to each market participant for short term bilateral trades as follows:

 (a) The report shall provide unidirectional ATC from each potential market participant to the specific market participant;

 (b) The report shall contain at least 8760 hour time slots of the 12 months following the report issue;

 (c) The report shall be published every week by Thursday 12:00; and

 (d) An updated report shall be published within 1 day of a new bilateral trade approved by *RPCC*.

(2) *RPCC* shall publish annually the ATC information specific to each market participant the 20 year ahead forecast as follows:

 (a) The report shall provide unidirectional ATC from each potential market participant to the specific market participant;

 (b) The report shall contain at least 5 year time slots of the 20 years following the report issue;

 (c) The report shall be published by 30 June and 31 December each year.

2.8 Dispute of transmission capacity

(1) *RPCC* shall make all relevant information available to a *TSO* querying the ATC calculation in their system including but not limited to:

(a) The network models used for the calculation;

(b) Relevant network, generation and load data used for the determination of ATC;

(c) The methodology and assumptions used for the determination of ATC; and

(d) The results of studies undertaken.

(2) The *TSO* shall formally communicate with *RPCC* any concerns with respect to the methodology, data used or results;

(3) *TSO* queries relating another *TSO* network shall be reviewed by an independent party;

(4) Should there be a dispute between *TSOs* and RPCC that cannot be resolved by the parties, then the RPCC Board shall appointment an independent review;

(5) The RPCC board shall make the final determination in resolving a dispute.

3. Electricity Balancing Code

3.1 Objective of Balancing Code

(1) Enhancing efficiency of balancing GMS and national balancing arrangements;

(2) Integrating balancing arrangements and promoting the possibilities for exchanges of balancing services while contributing to operational security.

3.2 Role of TSOs

(1) Each *TSO* shall be responsible for obtaining balancing services from balancing service providers in order to ensure operational security.

(2) Each *TSO* shall make surplus balancing service provider bids available for *TSO* – *TSO* trading. The surplus bids can be aggregated by the *TSO*.

(3) Each *TSO* is encouraged to obtain balancing services from other *TSOs* where this makes economic sense and does not compromise operational security.

3.3 Role of balancing service providers

(1) A balancing service provider shall qualify for providing balancing energy or balancing capacity which are activated or procured by the connecting *TSO* or, in a *TSO-TSO* model, by the contracting *TSO*. The qualification criteria shall be defined by *RPTCC.*

(2) Each balancing service provider shall submit to the connecting *TSO* its balancing capacity bids.

(3) Each balancing service provider participating in the procurement process for balancing capacity shall submit and have the right to update its balancing capacity bids before the gate closure time of the procurement process.

(4) Each balancing service provider with a contract for balancing capacity shall submit to its connecting *TSO* the balancing energy bids or integrated scheduling process bids corresponding to the volume, products, and other requirements set out in the balancing capacity contract.

3.4 Role of RPCC for balancing energy

(1) *RPCC* shall develop a platform for the *TSO - TSO* exchange of balancing energy.

(2) The *RPCC* energy balancing platform shall consist of at least the following functionality

(a) the *TSO-TSO* activation optimization function,

(b) common merit order lists, from the activation optimization function, to exchange all *TSO- TSO* balancing energy bids and

(c) the *TSO-TSO* settlement function.

3.5 Balancing market rules

(1) *RPCC* shall develop Balancing Market Rules for approval by the RPCC board.

(2) The Balancing Market Rules shall be consistent with the other market rules and the principles set out in intergovernmental agreement/s.

(3) The balancing market rules shall at least include:

(a) Balancing market products;

(b) Qualification criteria for products;

(c) Registration of balancing service providers;

(d) Time frames for trading including gate closure time;

(e) Capacity payments methodology determination;

(f) Format of bids and offers;

(g) Merit order determination;

(h) Optimization algorithm methodology;

(i) Methodology for congestion determination;

(j) Activation methodology for bids and offers;

(k) Balancing and imbalance energy price determination; and

(l) Settlement process.

3.6 *Role of RPCC for imbalance energy calculation in the absence of a Balancing Market*

(1) *RPCC* shall develop a platform for the imbalance netting process, which shall be based on common governance principles and business processes and shall consist of at least the imbalance netting process function and the *TSO-TSO* settlement function.

3.7 *Imbalance Settlements*

(1) The settlement processes shall:

(a) establish adequate economic signals which reflect the imbalance situation;

(b) ensure that imbalances are settled at a price that reflects the real time value of energy;

(c) provide incentives to balance service providers to help the system balance or to restore its balance;

(d) avoid distorting incentives to balance service providers and *TSOs*;

(e) support competition among market participants;

(f) provide incentives to balancing service providers to offer and deliver balancing services to the connecting *TSO*;

3.8 *Imbalance energy settlement rules in the absence of a Balancing Market*

(1) *RPCC* shall develop Imbalance Energy Settlement Rules for approval by the *RPCC* board.

(2) The Imbalance Energy Settlement Rules shall be consistent with the other market rules and the principles set out in intergovernmental agreement.

(3) In the absence of a balancing market the settlement of imbalance energy can be settled by using one or more of the three methods proposed below and as approved by the *RPCC* Board

(a) “in-kind” imbalance energy settlement;

(b) “marginal cost” imbalance energy settlement;

(c) “market reference price” imbalance energy settlement; or

3.8.1 “In-kind” imbalance energy settlement

(1) “In-kind” imbalance energy settlement is calculated as Inadvertent Energy as defined in the System Operations Code.

(2) Inadvertent energy interchange accumulated shall be paid back during the same time-of-use and same season-of-use in which it was accrued, e.g. peak, standard and/or off-peak, unless otherwise agreed by the affected *Control Areas / TSOs* or *Participants*.

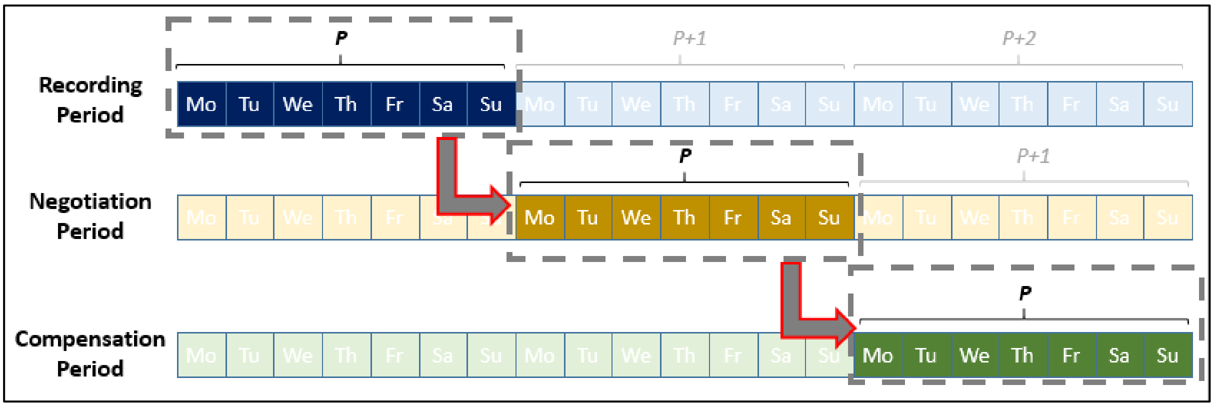
(3) The time-of-use and season-of-use definition shall be published by the RPCC.

(4) Each *Control Area / TSO* or *Participant Operator* shall submit a weekly summary of Inadvertent Energy interchange (over the "recording period" in Figure 1) to the *RPCC* Coordination Centre by 12:00 on the first working day of the week.

(5) *RPCC* Coordination Centre shall reconcile the Inadvertent Energy interchanges such that the sum of all interchanges is zero. The process of netting to zero shall be agreed to net off meter errors.

(6) Over the following week (the "negotiation period" in Figure 1), each participant which had a shortfall ("seller") shall propose a suitable time to return the Inadvertent Energy to the affected market participant(s) ("buyer") for the following week starting on Monday at 00h00 and ending on Sunday 24h00 (the "compensation period" in Figure 1).

Figure 1: Timeline for the recording and settlement of imbalances



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(7) Once an agreement between the buyer and the seller is reached, the buyer shall notify the *RPCC* and request for acceptance of the balancing trade before the end of the negotiation period.

(8) The *RPCC* shall check whether there is sufficient ATC and if so update the trading schedules, update the customised ATC reports and circulate to each potential buyer. Should there not be sufficient ATC the seller/s (i.e. participant which have a shortfall) shall agree a suitable time in discussion with *RPCC* by the end of the negotiation period.

(9) Should it not be possible to pay back inadvertent energy or no agreement can be reached between parties then inadvertent energy shall be settled using "marginal cost" imbalance energy settlement method.

3.8.2 "Marginal cost" imbalance energy settlement

(1) "Marginal cost" imbalance energy settlement is calculated as Inadvertent Energy as defined in the System Operations Code.

(2) *RPCC* shall calculate a reference price based on the marginal unit type on the system for that particular settlement period.

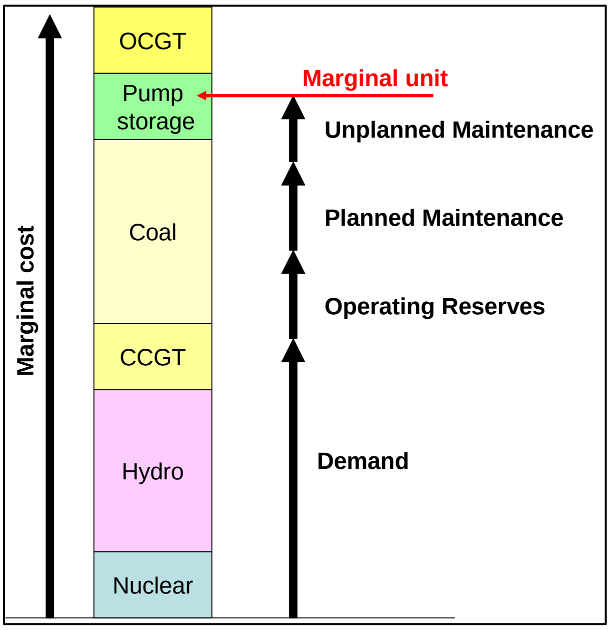
   (a) The marginal unit stack is fixed for the trading year ahead and the system demand at the time where imbalance has occurred is known.

   (b) The marginal unit is determined by adding operating reserves to the demand, planned maintenance and unplanned maintenance, Figure 2.

(c) The planned maintenance shall be determined from planned maintenance schedules provided by *TSOs* to *RPCC*.

(d) The unplanned maintenance shall be a percent of the demand as determined by *RPCC*. The unplanned maintenance percentages can be seasonal.

Figure 2: Example of marginal unit cost determination



(3) One month before the start of the trading year, each *TSO* shall provide the *RPCC* the following information:

(a) Installed Generation (including, for each unit, the unit's size and marginal cost);

(b) Planned maintenance schedule; and

(c) Unplanned maintenance percentage for the current trading year.

(4) *RPCC* shall be responsible for calculating the marginal unit stack applicable for the trading year ahead based on the information collected, and distributing the results to all market participants at the start of each trading year.

(5) *RPCC* shall update the stack monthly based on current information including:

(a) Current fuel prices; and

(b) Updated planned maintenance schedules.

(6) *RPCC* shall publish the following months balancing stack and prices to Participants 3 working days before the first day of the next month

(7) *RPCC* shall calculate reference prices for each zone should there be congestion

(8) *RPCC* shall adjust the market reference price by the system performance method described in section 3.9

(9) *RPCC* or appointed settlements agency shall raise invoices and credit notes to affected parties in accordance with the agreed rules.

3.8.3 "Market reference price" imbalance energy settlement

(1) "Market reference price" imbalance energy settlement is calculated as Inadvertent Energy as defined in the System Operations Code.

(2) The market reference price shall be determined from Day Ahead or intraday market trading prices.

(3) The market reference price can be adjusted by an agreed fixed percentage as agreed by the *RPCC* board. Separate peak, shoulder and off-peak adjustments shall also be possible.

(4) *RPCC* shall calculate market reference prices for each zone should there be congestion.

(5) *RPCC* shall publish the market reference prices to *Participants* as soon as prices are available for each settlement period.

(6) *RPCC* shall adjust market reference price by system performance method described in section 3.9 .

(7) *RPCC* or appointed settlements agency shall raise invoices and credit notes to affected parties in accordance with the agreed rules.

3.9 Determination of cause of imbalance energy in the absence of a Balancing Market

(1) The calculation of the cause of imbalance shall be determined using the NERC CPS1 criteria.

(2) Any *Participant* where the calculated NERC CPS1 value is less than 100% for the imbalance settlement period shall be deemed to be one of the parties causing the imbalance.

(3) The *RPCC* shall determine the penalty for *Participants* who are causing imbalances. This can include but not restricted to the following:

(a) A fine imposed on the *Participant;*

(b) An adjustment (penalty) to the imbalance energy price paid.

3.9.1 NERC CPS1 calculation for determining which *Participants* are the cause of imbalance energy:

(1) CPS1 is calculated as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor (CF) is a ratio of the accumulating clock-minute compliance parameters for the imbalance energy reconciliation period

$$CF = \frac{CF_n}{(\epsilon_1)^2}$$

The rating index CF_n is derived from the average clock-minute compliance parameters derived from the one-minute averages of Reporting ACE, Frequency Error, and Frequency Bias Settings.

A clock-minute average is the average of the reporting *TSO*, *Control Are*a or *Control Block's* valid measured variable (i.e., for Reporting ACE (RACE) and for Frequency Error) for each sampling cycle during a given clock-minute.

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE_i}{-10B_i} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

ACE_i is the clock-minute average of ACE

B_i is the frequency bias of the *TSO/Control Area* or *Control Block*. For those areas with variable bias, an area should accumulate ACE/(–10B) through the AGC cycles of a minute, and save the averaged value at the end of the minute as the clock-minute value of $ACE_i/(-10B_i)$,
Epsilon1, ϵ_1 , is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over a given year. The bound is the same for every *TSO/Control Are*a or *Control Block* within an Interconnection. The targeted frequency deviation is determined by *RPCC*.
ΔF, is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and **F_s** is scheduled frequency for the Interconnection,
i is representative of the *TSO/Control Area* or *Control Block*,
Period is defined as the imbalance energy period:

3.9.2 Penalty for *Participant*s who are causing imbalances

(1) The penalty for imbalances is dependent on whether the frequency is high or low is as follows:

(a) A frequency deviation of Epsilon1 (ϵ_1) from nominal frequency represents approximately the 66% of the targeted bound assuming a normal distribution. Twice ϵ_1 from nominal represents the 95% of the targeted bound.

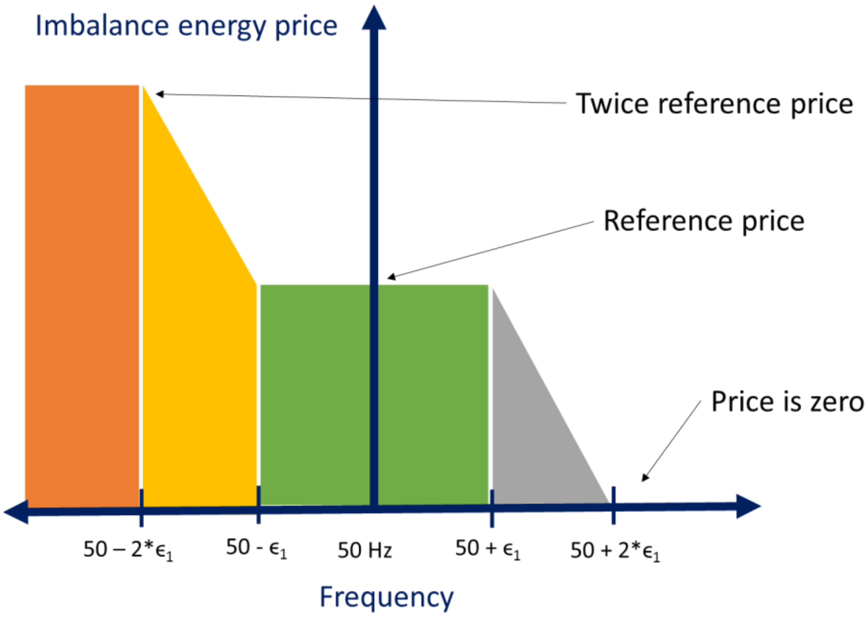
(b) If frequency is less than twice Epsilon1 ($2*\epsilon_1$) from nominal then the *TSO/Control Area* or *Control Block* whose CPS1 performance is less than 100% is causing the low frequency by under producing and should pay a penalty of twice the reference price for imbalance energy.

(c) If frequency deviation is less than Epsilon1 (ϵ_1) imbalance energy is charged at the reference price.

(d) If frequency is greater than twice Epsilon1 ($2*\epsilon_1$) from nominal then the *TSO/Control Area* or *Control Bloc*k whose CPS1 performance is less than 100% is causing the high frequency by over producing and should provide imbalance energy at no cost.

(e) For frequency deviations between Epsilon1 (ϵ_1) and twice Epsilon1 ($2*\epsilon_1$) a linear interpolation on the price shall apply as shown in Figure 3:

Figure 3: Imbalance energy price penalty calculation



3.10 “Balancing market” imbalance energy settlement

(1) Imbalance energy is the difference in energy flows between the final approved *Participant* schedules taking into account activated balancing energy bids and offers including Ancillary Service and Operating Reserve provision.

(2) *RPCC* shall be responsible for determining the rules for energy imbalance settlement from activated bids and offers. Such rules shall be approved by the *RPCC* Board.

(3) The imbalance energy price shall be determined from the approved balancing market rules.

(4) *RPCC* or appointed settlements agency shall raise invoices and credit notes to affected parties in accordance with the agreed rules.

3.11 Reporting

(1) *RPCC* shall set up performance indicators for balancing markets that will be used in the annual reports. These performance indicators shall reflect:

(a) the availability of balancing energy bids, including the bids from balancing capacity;

(b) the monetary gains and savings due to imbalance netting, exchange of balancing services and sharing of reserves;

(c) the total cost of balancing;

(d) the economic efficiency and reliability of the balancing markets;

(e) the possible inefficiencies and distortions on balancing markets;

(f) the efficiency losses due to specific products;

(g) the volume and price of balancing energy used for balancing purposes, both available and activated;

(h) the imbalance prices and the system imbalances;

(i) the evolution of balancing service prices of the previous years;

(j) the comparison of expected and realised costs and benefits from all allocations of TSO-TSO capacity for balancing purposes.

(2) *RPCC* shall provide monthly market information reports which contain at least the following:

(a) the availability of balancing energy bids, including the bids from balancing capacity;

(b) the total cost of balancing;

(c) the volume and price of balancing energy used for balancing purposes, both available and activated;

(d) the imbalance prices and the system imbalances;

ANNEX: Market Code – History of Comments

#	Country	Reference section in the document	Country Comment	Consultants Review and Recommendation	Country Acceptance
1.	Thailand	Section 2.15	Paragraph 2.15.1 should be corrected.	Corrected to 2.5.4 in version 0.2.	
2.	Thailand	Section 2.5.3 (2)	Raining Season may be added: The input data sets (“Winter”, “Summer”, “Raining”) are the GMS reference cases based on the GMS snapshot that have to follow the following rules:	Agree added “wet / dry” as an option to “summer / winter” to section 2.5.3 (2) in version 0.2.	
3	Thailand	Section 2.5.3	The right-handed side of these equations should not be identical: $P_{new}^{inc} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}$ $P_{new}^{dec} = P_i + \Delta E \cdot \frac{P_i}{\sum_n (P_i)}$ Font size should be as same as those in the text.	European policy 4 formulas use the same equation but delta E sign changes. Remark added to this effect (same as in European Policy 4 in version 0.3. Font size corrected in section 2.5.3. 4 in version 0.2.	

#	Country	Reference section in the document	Country Comment	Consultants Review and Recommendation	Country Acceptance
4	Thailand	Section 3.9	North American Electric Reliability Corporation (NERC) standard is proposed for determination of cause of imbalance energy in this section. The proposed methodology should be based on ENTSO-e instead of NERC as the previous codes are based on the ENTSO-e.	Disagree – The European code does not have performance criteria and this has led to a recent dispute between all members and Kosovo. No action could be taken against defaulting party. Similarly no performance criteria were in Gulf codes leading to many disputes. This was changed a few years ago.	