CPPA-G/2023/CEO/9412-15 December 28, 2023

REGISTRAR OFFICE
Diary No. 03
Date: 1-1-24

Registrar NEPRA
NEPRA H/Q
Islamabad

Subject: SUBMISSION OF THE FINAL TEST RUN REPORT TO THE AUTHORITY

Reference: Determination No. NEPRA/R/DG(LIC)/LAM-01/8889 dated May 31, 2022

This is with reference to the determination issued by NEPRA dated May 31, 2022, which included (i) Grant of MO License to CPPA-G (ii) Approval of the Market Commercial Code for Test Run and (iii) Approval of six (6) months' Test Run Plan. The actions encapsulated in the Test Run Plan had specific obligations assigned to the relevant power sector entities including CPPA-G. Further, CPPA-G was assigned the role of central coordinator / facilitator regarding the implementation of Test Run Plan.

2. In the aforesaid determination (Section H (Decision of the Authority) sub section III, part (c)), CPPA-G has been directed to submit a Final Test Run report to the Authority in consultation with relevant power sector entities. For this purpose, CPPA-G held several consultative sessions during the Test Run Phase to discuss findings and observations of the test run.

3. Accordingly, CPPA-G has prepared a Final Test Run Report in consultation with the relevant power sector entities. The final report presents a cumulative status update of the test run phase and the aggregate status of activities starting from June 2022. This report begins with an executive summary highlighting key activities carried out under the Test Run Plan. Furthermore, this report also highlights a summary of the Settlement Statements issued during the test tun and also includes the proposed Commercial Code amendments. The remaining part of the report provides compliance status of specific directions issued by the Authority and a high-level status update on each of the twenty-four (24) actions as included in the Test Run Plan.

4. Henceforth, the Final Report was presented to CPPA-G Board which directed CPPA-G management to held consultative session on the report and also get it vetted from an International Consultant before forwarding the same to the Cabinet Committee on Energy (CCoE) through Power Division seeking approval for its submission to NEPRA for final approval. Accordingly, the CCoE in its meeting dated November 22, 2023 has approved the submission of Test Run Report to NEPRA and authorized CPPA-G to submit the same to the Authority. The said decision of CCoE has also been ratified by the Federal Cabinet in its meeting held on December 13, 2023.

5. In view of the above, following documents are hereby submitted to the Authority for consideration: (i) the Final Test Run Report (Annex-I) (ii) revised Market Commercial Code incorporating proposed amendments in light of the Test Run (Annex-II), and (iii) Minutes of the Consultative Session on the Test Run Report (Annex-III).

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29/12/23

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- Head MOD CPPA-G
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I

CENTRAL POWER
PURCHASING AGENCY

CTBCM

[CTBCM: The Competitive Trading Bilateral Contract Market]

FINAL TEST RUN REPORT

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LIST OF ACRONYMS

Acronym	Abbreviation
ASC	Ancillary Service Charges
API	Application Programming Interface
BMC	Balancing Mechanism for Capacity
BVM	Best Value Metered
CCOP	Commercial Code Operating Procedure
CCRP	Commercial Code Review Panel
CTBCM	Competitive Trading Bilateral Contract Market
CDP	Common Delivery Point
EMP	Electricity Market Professional
BME	Balancing Mechanism for Energy
EMO	Economic Merit Order
ERP	Enterprise Resource Planning
DISCO	Ex-WAPDA Distribution Company
FSS	Final Settlement Statement
MCC	Market Commercial Code
MMS	Market Management System
MO	Market Operator
MP	Market Participant
MPA	Market Participant Agreement
MDI	Maximum Demand Index
MSP	Metering Service Provider
NEPRA	National Electric Power Regulatory Authority
NTDC	National Transmission and Dispatch Company
PSS	Preliminary Settlement Statement
SP	Service Provider
SPA	Special Purpose Agent
SQL	Structured Query Language
SO	System Operator
SDXP	System Operator Data Exchange Portal
T&D	Transmission & Distribution

PREAMBLE

National Electric Power Regulatory Authority (NEPRA) granted Market Operator (MO) license to Central Power Purchasing Agency Guarantee Ltd. (CPPA-G) vide a determination dated May 31st, 2022. The Authority approved the Market Commercial Code for test-run during the soft launch of the Market and a test-run plan. The test-run plan had various actions to be performed by relevant power sector entities.

Further, NEPRA assigned to CPPA-G the role of central coordinator / facilitator for implementation of the test-run plan which was monitored on a bi-weekly basis by NEPRA. Moreover, the Authority also directed CPPA to furnish monthly and final test run reports.

The test run phase of the CTBCM was defined as the pre phase before CTBCM goes live. The test-run phase – also sometimes referred to as "trial run", "dry run" or "parallel run"– was aimed to simulate the CTBCM transactions under "actual and real conditions" without imposing any financial obligations on the market participants and to test all IT systems, applications and software in real time scenarios.

In the test run phase, the readiness of relevant power sector entities to provide data inputs for the Market Management System (MMS) and other related IT systems was carried out. In this phase, the market participants were made aware of the MMS data requirements and processes, and they successfully completed their internal IT and operational changes to accommodate the new system and its associated procedures. Specifically, this phase also ensured that the power sector entities undergo thorough exercise of relaying and processing the relevant data sets as required.

The test-run phase also allowed market participants to review and evaluate the output data reports, generated from MMS, in relation to their operational and commercial needs. This hands-on experience and knowledge gained will enable them to participate in the competitive wholesale market and make informed decisions when financial implications are put into effect after the launch of the CTBCM.

EXECUTIVE SUMMARY

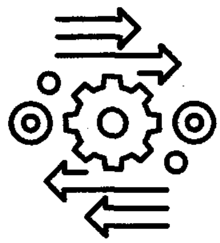
The CTBCM Test Run Plan was approved by NEPRA as a part of its determination for MO License. Test Run Plan was segregated into three groups namely:

(i) Market Commercial Code Actions
(ii) IT Tools and Systems and
(iii) Awareness Sessions and Reports, and enlisted actions therein had specific obligations assigned to the relevant power sector entities.

This report is prepared by the Market Operator in consultation with NTDC, DISCOs and other relevant stakeholders as per directions of the Authority, which includes the amendments proposed in the Commercial Code, update on the test run plan actions, findings and problems identified during the trial run and recommendations for improvement thereof.

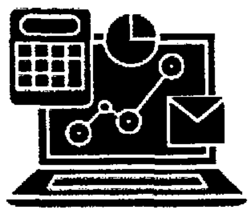
Following are the key updates pertaining to the implementation of test run actions:

1. **<u>Actions under the Market Commercial Code:</u>**



i. Commercial Code Review Panel established and notified.
ii. Configuration of legacy contracts in Market Management System completed.
iii. Balancing Mechanism for Energy (BME) being regularly executed along with issuance of PSS and FSS from June 2022 till date.
iv. Firm Capacity calculated as per provisions of the Commercial Code.
v. Ex-Ante Capacity Obligations were determined for all Ex-WAPDA DISCOs and KE as per the provisions of the Commercial Code.
vi. Amounts of Security Cover & Settlement Guarantee Cover determined.
vii. Opening of Bank Accounts completed.
viii. Commercial Code Operating Procedures developed and submitted to NEPRA.

2. **<u>Test Run Tools & Systems:</u>**



i. Implementation of Market Management System Phase 1 completed.
ii. ERP financials module developed and operationalized.
iii. Market Operator website developed.
iv. IT application associated with market operations including Marginal Price application, SDXP, Variable Cost submission portal developed and operationalized.

v. Through SMS, data Integration of MSP with MO completed.

3. **Awareness, Capacity Building, Test Run Sessions, and Reports**

i. Organization of roadshows in Lahore, Karachi, Peshawar, and Islamabad.
ii. Five consultative sessions with stakeholders conducted on Test Run Actions.
iii. 14 online awareness sessions conducted on CTBCM framework.

Besides the key updates as stated above, the following paragraphs highlight the most important findings of the test-run. The details of these findings and information regarding other actions undertaken during the test run have been elaborated into the relevant sections of this report.

The market governance ensures that all the transactions in the market are happening at arm's-length. The importance of the market governance is explained in detail in Section 4 of this report, however, as per the CTBCM design and the Market Commercial Code, typically the following two types of transactions may happen in the Market:

i. Where the buyers and sellers have contracted their Energy fully and Imbalances may arise due to centralized economic dispatch.
ii. A Market Participant has installed more Generation Capacity than its bilateral contracts and is selling the surplus Energy at the System Marginal Price.

In the transaction type (i) above, the Imbalances are a natural consequence of the dispatch decisions based on Economic Merit Order (EM)) and there can be profits for Market Participants over and above the variable generation cost while the System Marginal Price may be optimized. Similarly, in the transaction type (ii), in the short run, some extraordinary profits may occur if the variable generation cost of the Generator is significantly lower than the System Marginal Price. This profit is not arising due to CTBCM design or centralized economic dispatch, but it may be arising due to departure from the arm's length transactions principle. The Authority may ensure to bring up the market governance and monitoring system for identifying and adjudicating transactions that deliberately deviate from the arm's length transaction principle and apply penalties thereof. While penalizing, the benefit of such transaction may be transferred to the regulated consumers through sale to SOLR.

Therefore, it is necessary to highlight that the Authority may consider such market transactions, and deep analysis of such transactions may be considered to ensure effective market governance while providing the determination w.r.t transaction type (i) and (ii) above.

During the trial run, the Balancing Mechanism for Energy (BME) was executed successfully, and the Market Operator have been issuing the settlement statements since June 2022, however, it is pertinent to mention here that following observations require consideration of the Authority:

i. **Data provision by the Metering Service Provider:**
   a. The NTDC as Metering Service Provider (MSP) provides the hourly data in a manner that it undertakes an exercise at month end where it matches the manually collected data with the SMS data because of lack of infrastructure at certain metering points (43 number of meters) as mentioned in Section 8.2 below.
   b. The requirement for the market is that all metering points shall have Secured Metering System (SMS) on primary as well as backup meters so that the data collection system can be standardized on automatic meter reading and subsequently the metering data shall be used on hourly, daily, or weekly basis for its intended purposes as per Market Commercial Code.
   c. There should be a sufficient inventory of meters maintained at all times to cover meter failures.

ii. **Distribution Losses:**
   a. The Commercial Code specifies a mechanism to apply the distribution losses on the inter-DISCO CDPs, however, as per existing practice, which is approved by the Authority, the settlement on inter-DISCO CDPs is done on the actual metered data and no losses are uplifted. Therefore, it is imperative that the benchmark losses determined by the Authority need to be revised for all relevant DISCOs as per the mechanism given in the Commercial Code so that the true benchmarks reflecting the revised mechanism of uplifting the losses can be established.
   b. In order to avoid any disputes in future, it is important that all DISCOs confirm, to the Market Operator, the configuration regarding the application of losses on the inter-DISCO transactions. The Market Operator has initiated this process and confirmation from DISCOs has not been received yet.

iii. **Auxiliary Consumption of NTDC:**
   a. The Authority may direct the NTDC to regularize its auxiliary consumption from the respective DISCOs before the CMOD.

iv. **Marginal Price:**

a. The labels as provided in the Commercial Code for each Generation Plant for identification being dispatched due to EMO or other services by the System Operator shall be updated upon finalizing the definitions for the different types of other charges.

b. The mechanism for discovery of System Marginal Price as provided in the Commercial Code needs to be further analyzed. This means that the discovery of System Marginal Price based on next plant of fully loaded (loaded above 95%) may be altered to the principle that the most expensive generation plant run on EMO other than the plants dispatched for other market charges including Ancillary Services. Besides the detailed methodology as provided in the Commercial Code, it is important that the SO ensures at all times i.e. for each hour, the System Marginal Price is set by the most expensive generation plant run on EMO other than the plants dispatched for other market charges including Ancillary Services.

v. Other Market Charges (Must Run Generation and Ancillary Services)

During the trial run, the calculation of compensation for Must Run Generation and Ancillary Services was performed by the Market Operator based on the data received from the System Operator, however, as per the approved Commercial Code for test-run, the Energy units (kwh) for compensation are required to be specified by the System Operator, which were not specified. Further, the mechanism for provision of this data has been improved in the revised Commercial Code which mandates the System Operator to provide this data to the Market Operator due to the reason that under the NEPRA Act, it is the obligation of the System Operator to procure the Ancillary Services. Besides the aforesaid matter, the following observations were made regarding Must Run Generation and Ancillary Services during the trial run:

i. Under the approved Commercial Code for test-run, the System Operator was required to identify the Congested Areas and Zones, however, this action is still pending on the part of the System Operator.

ii. The Market Commercial Code introduces the mechanism for charging of Imbalances arising due to partial loading of Generators by the System Operator to the respective Market Participants. The System Operator has to make dispatch decisions on the basis of EMO as per provisions stipulated in the Grid Code including the instruction for provision of ancillary services such as frequency regulation or voltage support. In case the partial loading of the Generation Plant is because of an action of the System Operator which is beyond EMO as provided in the Grid Code including the provision of ancillary services such as frequency regulation or voltage support, this may attract dispute from the Market Participants claiming that its Imbalance due to action of System Operator and it shall not be penalized to pay for higher System Marginal Prices.

Therefore, it is important that necessary regulatory directions shall be issued to the System Operator that specify the parameters under which a cheaper Generator can be partially loaded, and the Market Participant shall be compensated for any loss in such a case by the whole market as provided in the Commercial Code.

iii. In public hearings for FCA, the Authority doesn't allow deviations from Economic Merit Order (EMO) from time to time and also disallows any cost incurred on account of deviation from EMO to be passed on to the consumers and instead has charges such cost to the NTDC. It is therefore, necessary that the Authority may determine parameters for deviation from EMO in light of the provisions of the Commercial Code and Grid Code and specify which deviations from EMO will qualify for compensation as other market charges including Ancillary Services and which deviations will be charged to the NTDC or System Operator, as the case may be.

4. Commercial Allocation

The Commercial Allocation Factors, determined by the Market Operator as per provision of the Commercial Code, shall be used for the following three purposes:

a. Planning
b. Energy Imbalances
c. Capacity Invoices

The Commercial Allocation factors calculated on historical Capacity invoices data shall be used for planning purposes and Energy Imbalances only. For Capacity Invoices to the DISCO by the Special Purpose Agent (SPA), the following transition shall be adopted for calculation of the Allocation Factors:

a. At least three (3) years of coincidental MDI data shall be used for calculation of the Allocation Factors.
b. Installation of Commercial Metering System as per provisions of the Commercial Code and Grid Code on all Metering Points especially the Metering Points between PESCO and TESCO.

Once the Allocation Factors are calculated on the coincidental MDI data, then the same factors shall be used for all of the above three purposes as stated above.

In addition to the above, one of the inputs from the stakeholders is that the factors already calculated on historical Energy data in invoices shall be used for the calculation of Imbalances.

It is also important to highlight here the implications of Commercial Allocation for Suppliers of Last Resort (SOLRs) on settlement of their Energy Imbalances (procurement of Energy on System Marginal Price), for which the following areas need clarity in the regulatory framework:

i. How the Imbalances will be catered for in the base tariff and what would be the parameters therefor? Whether the Authority will consider the Imbalances as an in-efficiency and will not allow it to be passed on to the end consumers?
ii. If the Imbalances are made part of the tariff, then how the Fuel Charges Adjustment (FCA) will be determined? Whether there will be a separate determination of FCA for each SOLR or a single determination on uniform basis will be made by the Authority?
iii. During the regime of uniform tariff for consumers, any additional cost on account of Imbalances for SOLR to be added into its tariff, if not passed on to the consumers, may result in an automatic determination of subsidy which may have adverse effect on the subsidy planning by the Federal Government.
iv. The Authority may issue necessary mechanism for the cases where the Imbalances in the Balancing Mechanism for Energy occurs because of the directives of System Operator under any governmental policy, then under such case, whether such Imbalance for the shall be calculated or not by the Market Operator.

[illegible] Annual Settlement Statement

i. Excess Losses of Transmission Service Providers

a. The approved Commercial Code for test-run stipulates that the actual loss during any hour shall be charged to the Market Participants. Besides that, a mechanism was included in the Commercial Code for determination of any excess losses beyond the benchmark as set by the Authority for any Transmission Service Provider. However, during the trial run, it was observed that the losses are a bilateral matter between the Market Participants and the Transmission Service Providers, and the Market Operator shall not be involved in this transaction. Therefore, the Market Operator was unable to calculate the actual losses for the previous year and it is recommended to remove this section from the Commercial Code.

ii. Balancing Mechanism for Capacity

a. During the trial run, the Market Operator has performed the simulation on the excel sheet for the Balancing Mechanism for Capacity (BMC) based on data provided by the System Operator (i.e., Daily Log Reports, Availability of Thermal Plants) and Metering Service Provider (Energy injected into the Grid). However, the System Operator was required to provide certain parameters (i.e., Critical Hours, Capacity of Generators, Reserve Margin, Efficient Reserve, LIC of Reference Technology), as explained in Section 7 below, which were not obtained from the System Operator and certain parameters were calculated by the Market Operator and the transitory values as provided in the Commercial Code were used for this simulation.

b. The objective of BMC is to maintain a discipline in the Market by the Market Participants that they should not be drawing more Energy more than what they had contracted and informed as their peak demand at the time of determination of the Capacity Obligations and Generators shall also remain fully available. The BMC mechanism has been provided to impose a financial penalty for violation of the contracted capacity, whereas the technological and physical infrastructure may also be considered like there is always a maximum cap of physical limitation of interconnection that any Market Participant can't withdraw beyond that. This aspect may also be emphasized in the service agreement between TNOs and Market Participants.

c. For SOLRs, the Capacity Imbalances may occur due to the Commercial Allocation Factors which are based on non-coincidental MDIs data. The Commercial Allocation Factors based on coincidental MDI data will be determined in three years.

d. Because of non-availability of coincidental MDI data and the readiness of the System Operator to determine the input parameters of the BMC, it is recommended that the trial run of the BMC shall be extended for three years without having any financial implications so that that improvements can be made before its actual implementation.

6. Merit Order and Discovery of System Marginal Price

The software for merit order has been developed, tested, and deployed on the SDXP. The IPPs will be providing hourly variable cost for calculating the Marginal Price. However, for the purposes of payments under PPA, the Authority determines the actual Fuel Cost Component (FCC) of all such IPPs on monthly basis as average of the operations during a month. The hourly variable cost may be higher or lower than the Authority's determination as mentioned above. This scenario will result in the following:

Scenario	Imbalances for BPCs / Regulated Consumers	Imbalances for a Generator
Marginal Price is greater than actual FCC	Will be charged more than actual cost.	A Market Generator will get higher payment than actual cost whereas for a Legacy Generator, the DISCOs will get a higher payment than the actual cost.
Marginal Price is less than actual FCC.	Will be charged less than actual cost.	A Market Generator will get lower payment than actual cost whereas for a Legacy Generator, the DISCOs will get a lower payment than the actual cost.

It is pertinent to mention that a consultative session was held with the NEPRA team in this regard. In order to cater for such differences between the values used for determination of System Marginal Price and the actual FCC for the bilateral payment, the Authority may address this matter in its regulatory framework.

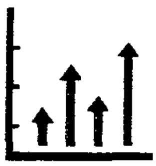
1- OBJECTIVES AND STRUCTURE OF THE REPORT

The objective of this report is to provide a comprehensive status update on the implementation of CTBCM test run plan to NEPRA so that a regulatory oversight is available on the readiness of the relevant power sector entities regarding operationalization of CTBCM and ensure that corrective measures could also be taken by the Regulator, if necessary, before the start of the Market.

This report presents the status of activities under the test run by highlighting the key activities and achievements that were carried out under the test run plan during the reporting period. In addition, this report also highlights amendments which are being proposed in the Market Commercial Code (MCC) which was approved for test-run at the time of grant of the license.

The remaining part of the report provides a summary of the issued Preliminary and Final Settlement Statements. The report also covers status of specific directions by the Authority and a high-level status update on all of the twenty-four (24) actions to be performed under the approved 6-month Test Run Plan is presented along with annexures pertinent to relevant sections of the report.

2- KEY HIGHLIGHTS OF TEST RUN



Issuance of Ex Ante Capacity Obligations

During the trial run, the Ex-Ante Capacity Obligations were determined by the Market Operator for all Ex-WAPDA DISCOs and KE as per provisions of the Commercial Code. The details of this activity are provided below in this report; however, the important observations are provided as under:

i. All Ex-WAPDA DISCOs and KE provided their forecasts as stipulated in the Commercial Code.

ii. The already existing contracts data was already available with CPPA-G.

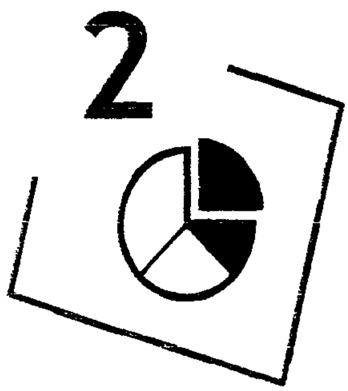
iii. The future planned projects were taken from the approved IGCEP for EX-WAPDA DISCOs.

iv. KE provided the list of its own Generators and the information related to its contracts with IPPs.

v. EX-WAPDA DISCOs and KE also provided the list of projects that they have bilaterally procured.

The above steps were executed successfully, and it was observed that the uncertainty margins for the 3rd and 4th years shall be linked with the Compound Average Growth Rate (CAGR) during the forecast instead of taking hardcoded percentages for which an amendment is proposed in the Commercial Code.

Submission of SPA Application & Code



In compliance with the directions of the Authority, CPPA-G has applied for the grant of registration as a Special Purpose Agent (SPA) along with SPA code to the Authority vide letter no. CPPA-G/2022/CEO/8943-45 dated 7th Nov 2022.

Issuance of Yearly Preliminary & Final Settlement Statements

During the trial run, the Balancing Mechanism for Capacity (BMC) was executed as per provisions of the Commercial Code to test the system, procedures and readiness of infrastructure and institutions involved in this process. The detailed observations are provided below in this report; however, some important points are as under:

i. The critical hours were identified by the Market Operator based on the data provided by the System Operator; however, it is the responsibility of the System Operator to provide this information and the System Operator has the capability to provide it. To this extent, the System Operator has failed to undertake this activity as per provisions of the Commercial Code and accordingly, the results under the trial run are based on Market Operator assessment and the System Operator may be directed to undertake this activity in the future.

ii. The Capacity data based on availability and generation during Critical Hours was required to be provided by the System Operator, however, it was calculated by the Market Operator based on data provided by the System Operator and the Metering Service Provider. The System Operator has the capability to provide this information and has failed to do undertake this activity as per provisions of the Commercial Code and the results under the trial run are based on Market Operator assessment and the System Operator may be directed to undertake this activity in the future.

iii. The Capacity Requirements of EX-WAPDA DISCO and KE were calculated on Energy withdrawal basis by the Market Operator based on the data provided by the Metering Service provider. This calculation basis on Energy (KWh) data is for simulation purpose whereas actual Capacity (KW) imbalance is required to be calculated based on development of infrastructure and methodology.

iv. For Reserve Margin, Efficient Reserves, Levelized Investment Cost (LIC) of Reference Technology, the transitory values provided in the Commercial Code were utilized for this simulation purpose. The System Operator is required All these values have to be determined by the System Operator for each BMC period for which System Operator has not initiated an action on this. It is recommended that the System Operator shall be directed to undertake this obligation. For the trial period, the BMC was executed on the transitory values.

Submission of CCOPs

CCOPs for Market and Contract Registration, Metering, Firm Capacity Certification, Capacity Obligation and Security Covers have been developed and initial drafts were submitted to the Authority for review in November 2022, however, the drafts updated as per the dry-run are attached herewith.

Firm Capacity Certification of Existing Generators

During the trial run, the Firm Capacity was calculated as per provisions of the Commercial Code for all the Legacy Generators except the Legacy Generators having bilateral contracts with Ex-WAPDA DISCOs. The details of observations are provided below in this report;.however, some importance points are provided below:

i. The availability of Legacy Generators based on 1994 power policy is not available on hourly basis and it was estimated through Daily Log Reports (DLR) provided by the System Operator.

ii. There was no clear bifurcation between the actual available capacity and the capacity not available but being paid as per the forced outage allowance.

iii. There are several practical issues in establishing the actual availability of Generation Plants due to structure of the Legacy Contracts.

iv. In majority of the Generation Plants, the availability information was available on Generation Plant basis instead of Generation Unit basis, therefore, the Firm Capacities for such Generation Plants have been determined on Generation Plant basis instead of Generation Unit basis.

v. Due to these issues, it was considered appropriate to change the Firm Capacity determination mechanism for thermal based Generation Units from historical availability data to the annual/dependable capacity test in which CPPA-G has years of experience to certify the Capacity of Generation Plants in a scientific manner and the Capacity certified through this method is reliable and dependable. Therefore, an amendment is proposed in the commercial code in this regard.

vi. It was also observed that there are certain hours where the load on the System is higher than those hours that are included in the System Peak Hours, therefore, a recommendation has been proposed to alter the System Peak Hours or determining the Firm Capacity of non-dispatchable Generation Plants.

The following sections describe in detail the actions performed during the trial run, important findings and observations and recommendations for improvement before the actual implementation of the market.

3- ACTUAL PRELIMINARY & FINAL SETTLEMENT STATEMENTS

From the start of the trial run period i.e., June 2023, CPPA-G has been issuing the preliminary and final settlements statements on monthly basis in a timely manner. CPPA-G also issued one Extraordinary Settlement statement for the month of June 2023. The summary statement of the PSS and FSS issued in the month of February 2023 is provided below as an example:

Preliminary Settlement Statement
Settlement Period: February - 2023

SN	Market Participant Id	Market Participant Name	Balancing Mechanism For Energy (BME) Charges PKR	Ancillary Services Charges PKR	Market Operator Fee PKR	Other Charges PKR	Adjustment from ESS PKR	Net Amount PKR
1	2	LESCO	0	0		-	-	0
2	3	ESCO	0	0		-	-	0
3	4	FESCO	0	0		-	-	0
4	5	GEPCO	0	0		-	-	0
5	6	HESCO	0	0		-	-	0
6	7	SEPCO	0	0		-	-	0
7	8	MEPCO	0	0		-	-	0
8	9	PESCO & TESCO	0	0		-	-	0
9	10	QESCO	0	0		-	-	0
10	12	K Electric	0	0		-	-	0

Figure 1: Preliminary Settlement Statement of February 2023

Final Settlement Statement
Settlement Period: February - 2023

SN	Market Participant Id	Market Participant Name	Balancing Mechanism For Energy (BME) Charges PKR	Ancillary Services Charges PKR	Market Operator Fee PKR	Other Charges PKR	Adjustment from ESS PKR	Net Amount PKR
1	2	LESCO	0	0	-	-	-	0
2	3	ESCO	0	0	-	-	-	0
3	4	FESCO	0	0	-	-	-	0
4	5	GEPCO	0	0	-	-	-	0
5	6	HESCO	0	0	-	-	-	0
6	7	SEPCO	0	0	-	-	-	0
7	8	MEPCO	0	0	-	-	-	0
8	9	PESCO & TESCO	0	0	-	-	-	0
9	10	QESCO	0	0	-	-	-	0
10	12	K Electric	0	0	-	-	-	0

Figure 2: Final Settlement Statement of February 2023

4- MARKET GOVERNANCE

Market governance refers to the rules, regulations, and mechanisms that govern the functioning of markets in an economy. It involves establishing a framework of policies and institutions that facilitate fair competition, protect the interests of stakeholders, and promote efficient resource allocation. One key aspect of market governance is the concept of arm's-length transactions, which are transactions that occur between two parties who have no special relationship or conflict of interest, and who negotiate and transact on equal footing without any undue influence.

Arm's-length transactions are an important principle of market governance as they ensure that transactions occur in a transparent and fair manner. In such transactions, parties are assumed to act in their own self-interest and are free to negotiate and agree on the terms and conditions of the transaction without any external pressures or biases. This helps in ensuring that prices are determined through market forces of supply and demand, and that the allocation of resources is efficient and based on economic considerations rather than personal relationships or biases.

Arm's-length transactions also promote competition in markets by preventing anti-competitive practices such as collusion or price-fixing. When transactions are conducted at arm's length, parties are not allowed to engage in anti-competitive behaviors that distort market outcomes, harm consumers, or hinder entry by new competitors. This fosters a level playing field for all market participants, encourages innovation, and enhances overall market efficiency.

Another key aspect of arm's-length transactions is that they promote accountability and transparency in market activities. Parties engaging in arm's-length transactions are expected to provide accurate and complete information about the terms, conditions, and risks associated with the transaction. This promotes transparency, trust, and confidence among market participants, and enables informed decision-making. It also helps in mitigating information asymmetry, which can lead to market failures or distortions.

Market governance and arm's-length transactions are also important for protecting the interests of stakeholders, including consumers, investors, and the public at large. Arm's-length transactions help in ensuring that consumers have access to a wide range of choices, competitive prices, and quality products/services. It also protects the interests of investors by ensuring that transactions are conducted in a fair and transparent manner, and that investors are treated equitably. Moreover, arm's-length transactions promote the public interest by preventing undue concentration of economic power and fostering a competitive and dynamic market environment that benefits society as a whole.

However, it's important to note that arm's-length transactions are not always foolproof, and there may be instances where parties may engage in unethical or fraudulent behavior to manipulate market outcomes. Therefore, effective market governance requires robust regulatory frameworks, enforcement mechanisms, and monitoring systems to ensure that arm's-length transactions are conducted in a manner that is consistent with the principles of fairness, transparency, and accountability.

In conclusion, market governance and arm's-length transactions are critical for the proper functioning of markets and the overall health of an economy. They promote fair competition, transparency, and efficiency in transactions, protect the interests of stakeholders, and foster a competitive market environment. However, effective market governance requires ongoing vigilance and regulatory oversight to ensure that arm's-length transactions are conducted in a manner that is consistent with the principles of good governance, and that any instances of unethical or fraudulent behavior are promptly detected and addressed.

The role of System Operator in Market Monitoring is also very important as majority of the data used by the Market Operator in the settlement is generated at the System Operator and the System Operator has deployed the necessary IT infrastructure to manage this data effectively. The role of the System Operator regarding ensuring the integrity of the data that it generates is also very important. Therefore, procedures shall be in place at the System Operator to ensure the integrity of the data. The system operator shall keep electronic record of all the necessary information needed to explain its operation. It will be of utmost importance for Market Monitoring that this data shall be securely shared with the market monitoring team of NEPRA for analysis.

5- PROPOSED AMENDMENTS TO THE MARKET COMMERCIAL CODE

At the time of grant of MO license, the Authority also approved the Market Commercial Code. During the test run period, the Market Commercial Code is being implemented on a trial-run basis. The concepts, procedures and formulas mentioned in the approved Market Commercial Code were put through rigorous testing.

During the testing and implementation of the Commercial Code, certain areas have been identified for further refinement and amendment in respective provisions. The proposed amendments in the approved Commercial Code are tabulated in Annex 1-C of this report for consideration of the Authority along with reasons for such amendments.

For clarity of purpose, these proposed modifications have been categorized into two broad groups i.e.

(A) Technical

(B) Clarifications and Typos.

It is clarified here that few other amendments for improvement of language have also been incorporated in the approved Commercial Code, however, these are not made part of Annex 1-C explicitly in order to include only the important amendments in the table given in Annex 1-C. All such amendments are available in the red-line version of the revised Commercial Code submitted along with this report.

6- RECOMMENDATIONS REGARDING REGULATORY FRAMEWORK

The associated regulatory framework for CTBCM has been prepared by the Authority through notification of various market-related regulations, whereas some regulatory documents are still in the process of regulatory approval. In accordance with Section H Part (c) of the MO License Determination, CPPA-G is required to submit "recommendations, if any, regarding the amendments in any other applicable document".

To comply with this direction, a comprehensive report will be furnished in due course of time. This report will outline the recommendations for proposed amendments to the regulatory framework and will be submitted to the Authority for consideration.

7- COMPLIANCE WITH SPECIFIC DIRECTIONS OF THE AUTHORITY

The Authority vide determination dated May 31, 2022, issued specific directions to CPPA-G pertaining to the Market Operator License and also required CPPA-G to implement the test run plan.

Specific directions to CPPA-G pertaining to the Market Operator license include coordinating with DISCOs, NTDC, KE & others for test run plan of Market Commercial Code & other activities, submission of SPA Registration Application and draft Agency Code, submission of roadmap plan for legal segregation of MO and SPA, functional separation plan of MO & SPA, development of a robust IT Strategy and designation of a senior officer from Market Operations that shall act as a primary focal person with the Authority.

In order to comply with the directions of the Authority, a meeting of the Market Implementation Support Committee (MISC) of CPPA-G Board was held on 7th June 2022. In the said meeting, directions of the Authority were discussed and consequently the directions in the form of specific actions were assigned by the MISC to the respective departments of CPPA-G for timely compliance. Subsequently, a meeting of the Board of Directors was also held on 10th June 2022 which ratified the decisions and internal delegation of respective tasks pertaining to CTBCM test run as recommended by the MISC.

In compliance with the direction of the Authority to designate a senior officer from Market Operations for coordination related to CTBCM test run, CPPA Board designated Head Market Operations and Development for communication with the Authority. This nomination was conveyed to NEPRA vide letter no. CPPA-G/CEO/2022/MOD/1461-1463 dated 15th June 2022.

Similarly, in compliance with the direction of the Authority to submit a proposed plan for legal and functional segregation of SPA and MO, the plan was submitted to the Authority vide letter no. CPPA-G/CEO/2022/MOD/1487-1893 of CPPA-G dated 29th June 2022. The proposed roadmap comprised of some actions that would lead to the functional segregation in terms of management and accounting. In this connection, all the HR related matters of MO including promotions, hiring, staffing etc. Are being dealt with separately and as such the MO and SPA functions are treated as separate business units in this regard. Similarly, Market Fee comprises separate revenue requirement of both functions and corresponds to distinct budgetary allocation and resulting expenditure. The development of ERP financials for MO has also been completed and ERP financials is now "Go Live". The bank accounts for MO related to market operations are in the final stages of operationalization.

With the conclusion of the functional segregation as explained above, the Authority is requested to reconsider its direction vide clause H part (d) of the determination and allow extension in timeline for the subsequent legal separation of SPA and MO for up to 5 years due to several practical reasons as learned during the test run period.

Another action of compliance was the submission of IT Strategy of CPPA-G for the Competitive Market which was timely submitted to the Authority vide letter CPPA-G/2021/CEO/SMD/1895-3 dated 30th June 2022.

During November, the application of CPPA-G for registration as SPA along with the code has been submitted to the Authority vide letter no. CPPA-G/2022/CEO/8943-45 dated 7th Nov 2022.

A tabulated summary of the status update regarding specific directions is attached at Annex I-B.

8- CTBCM TEST RUN PLAN - STATUS UPDATE

The Test Run Plan issued by NEPRA vide the above-mentioned determination has been segregated into three groups. Moreover, the entities responsible for implementation, facilitation and support have also been highlighted in the said test run plan along with firm timelines for execution thereof as shown in tabulated form at **Annexure - IA**.

The Test Run plan is segregated into following three groups:

1. Actions under Market Commercial Code
2. Test Run Tools and Systems
3. Awareness, Capacity Building, Test Run Sessions, and Reports

8.1 ACTIONS UNDER MARKET COMMERCIAL CODE

i) Establishment of Commercial Code Review Panel (CCRP)

The Commercial Code Review Panel (CCRP) is a panel of experts, composed of representation from all stakeholders, as per the composition defined in the approved Market Commercial Code (MCC). The purpose of the CCRP is to review any proposals for making any amendments in the Market Commercial Code and take necessary actions as required.

The CCRP has been notified vide CPPA-G's circular No. CPPA-G/2022/MOD/2096 dated October 25, 2022, including members from CPPA-MO, CPPA-SPA, NPCC, NTDC, WAPDA, STDC, DISCOs, K Electric and NEPRA.

For entities where no enrolled participants or associations exist, such as the Generators, Competitive Suppliers, Traders, and Bulk Power Consumers etc., nominations for CCRP from these categories cannot be acquired in accordance with the provisions of Commercial Code. Therefore, an interim solution has been proposed for the consideration of Authority in the Commercial Code Amendments referred to in Chapter 4 of this report.

ii) Preparation of Merit Order on Shorter Duration

The test run plan mandates to move towards real-time merit order, as is also the international practice, and shorten the duration of merit order preparation from currently 15 days to targeted 1 day. The internal deliberation on the preparation of merit order on a shorter period has been completed. CPPA-G held a high-level consultation with NPCC on July 27, 2022.

The first round of discussion with coal IPPS was conducted in August 2022 followed by a second round in September 2022 as planned. The IT application has been developed and the consequent training of IPPs on the same is planned to be conducted during April 2023.The application will be ready to "Go Live" soon after the training of the IPPs is completed.

Further, it is also important to highlight here that the Special Purpose Agent shall not be involved in provision of the variable cost data of the Legacy Generators to the System Operator. It is recommended that the provisions of the Grid Code may be amended in this regard.

iii) Enrolment of Market Participants & Service Providers

All stakeholders intending to participate in CTBCM need to be enrolled with the Market Operator (MO) as required under the MCC. This will be done by filing an admission application to MO, which once approved, would require the concerned Market Participant or Service Provider to sign a Market Participation Agreement (MPA) or Service Provider Agreement (SPA) as the case may be with the Market Operator.

In this regard, Market Participation Agreement (MPA) and Service Provider Agreement (SPA) drafts have been prepared in consultation with MRC Consultant and timely submitted to NEPRA for comments vide letter CPPA-G/2022/MOD/1485-86 dated June 30th, 2022. The comments from NEPRA were received on August 31, 2022. The MPA and SPA were also shared with relevant stakeholders and their comments have also been received. In light of those comments, both the documents have been revised.

Furthermore, the revised MPA has been submitted to NEPRA vide email dated 15th February 2023 and the revised SPA shall be submitted in due course of time.

DISCOs and NTDC were requested to submit their respective admission applications by 28th September 2022 vide letter no. CPPA-G/2022/MOD/2031-2043 dated 22nd September 2022 and letter no. CPPA-G/2022/MOD/2044-2046 dated 22nd September 2022 respectively.

Admission applications have been received from all ten Ex WAPDA DISCOs both in the role of the Supplier and Service Provider. However, the applications from NTDC and KE are still awaited.

NTDC and KE have been repeatedly reminded of the obligation latest vide letter no. CPPA-G/2023/MOD/0100-0104 dated 7th March 2023 and CPPA-G/2023/MOD/0097-99 dated 7th March 2023 respectively.

The MPA and SPA, as updated during the trial run, have also been shared with DISCOs, KE and NTDC for their feedback and the same will be shared with Authority after the feedback is received from these stakeholders.

iv) Contract Registration

This activity relates to the registration of bilateral contracts of market participants with the Market Operator. The Market Management System (MMS) has been made ready to register any bilateral contracts. It is pertinent to note that the calculation of imbalances has been configured in the MMS as per the Commercial Allocation determined in light of the proposed amendment in the Commercial Code.

v) Charging of Capacity based on Allocation Factors

This activity relates to converting the current charging mechanism of capacity charges to an allocation-based formula. Reference to the November 2020 NEPRA determination on CTBCM Detail Design and Implementation Roadmap, this process was approved, and allocation factors included in the approved MCC were to be used to make the requisite calculations.

In compliance to the Authority's directions, the capacity settlement statements for the months of June, July and August were issued to DISCOs vide CPPA-G letter no. CFO/GMF(CA&T)/Billing/16929-38 dated 28th September 2022.

Furthermore, a consultative session with Chief Financial Officers, Finance Directors and Director General MIRADs of all DISCOs was conducted on 4th October 2022. In the session, consensus was developed on charging mechanism of capacity based on allocation factors as follows:

The Commercial Allocation Factors shall be used for three purposes:

a. Planning
b. Energy Imbalances
c. Capacity Invoices

The allocation factors determined as per provisions of the Commercial Code are to be used by DISCOs for planning of future bilateral capacity procurement and Imbalances under CTBCM.

Furthermore, charging of capacity to DISCOs based on allocation factors should be based on following transition:

a. A transition of up to three (03) years be provided for payment of capacity charges. During this transition, the capacity will continue to be charged in accordance with the existing practice.

b. Three years will be the maximum time for the transition, however, based on the readiness of the system and the directions of the Authority, the shift may be made earlier. It was also discussed that a regulation may also be required by NEPRA that will specify the methodology providing the details of calculating contributions of DISCOs peaks to the system peaks.

c. As soon as the coincidental MDI based charging mechanism is established or implemented as per direction of NEPRA, the allocation factors shall be redetermined by the Market Operator based on shift to co-incidental MDI system contributions. Once the commercial allocation factors are updated, these shall be used for all of the three purposes i.e., Planning, Energy Imbalances and bilateral Capacity invoices.

The details of the above-mentioned recommendation to the Authority are attached as **Annexure II** (Minutes of Meeting of Consultative Session on Allocation Factors and Charging Mechanism of Capacity dated 11th October 2022) of the report.

vi) Execution of BME, Compensation for Must Run Generation and Ancillary Services (Monthly Settlement Statements)

Based on the methodology approved in the MCC, the determination of imbalances had to be carried out along with issuance of respective monthly settlement statements to all MPs.

Accordingly, the Balancing Mechanism for Energy (BME) was administered on monthly basis during the test run period and Preliminary and Final Settlement Statements for the months of June 2022 to February 2023 have been issued to the Market Participants.

The Authority has consistently disallowed any deviation from Economic Merit Order (EMO) and has also disallowed any cost incurred on account of deviation from EMO to be passed on to the consumers and instead has charged such cost to the NTDC. It is therefore, necessary that the Authority may determine parameters for deviation from EMO in light of the provisions of the Commercial Code and Grid Code and specify which deviations from EMO will qualify for compensation and which deviations will be charged to the NTDC or System Operator, as the case may be.

It is also important to highlight here the implications of Commercial Allocation for Suppliers of Last Resort (SOLRs) on settlement of their Energy Imbalances (procurement of Energy on

System Marginal Price), for which the following areas need clarity in the regulatory framework:

a. How the Imbalances will be catered for in the base tariff and what would be the parameters therefor? Whether the Authority will consider the Imbalances as an in-efficiency and will not allow it to be passed on to the end consumers?
b. If the Imbalances are made part of the tariff, then how the Fuel Charges Adjustment (FCA) will be determined? Whether there will be a separate determination of FCA for each SOLR or a single determination on uniform basis will be made by the Authority?
c. During the regime of uniform tariff for consumers, any additional cost on account of Imbalances for SOLR to be added into its tariff, if not passed on to the consumers, may result in an automatic determination of subsidy which may have adverse effect on the subsidy planning by the Federal Government.
d. What would be the solution if the Imbalances in the Balancing Mechanism for Energy occurs because of the directives of System Operator under any governmental policy, then under such case, whether it would be prudent to charge Imbalance to any SOLR for such hours where the System Operator has forced an SOLR to deviate from its Commercial Allocation. However, in the consultative sessions held during the trial run, the SOLRs agreed to pay for the Imbalances based on the Commercial Allocation.
e. Under the current regulatory regime, the Bilateral Contracts of DISCOs are not settled through the CPPA-SPA and the same will continue under the CTBCM regime. Whether the settlement of net metering through CPPA-SPA is in line with this principle?

Another important aspect is that the Market Operator has shared the configuration of the metering points in its Market Management System with all the DISCOs and has asked for confirmation regarding application of the Distribution Losses on these inter-disco points. The confirmation from the DISCOs is still pending. It is important that the DISCOs provide this confirmation so that there shall be no dispute in this regard.

vii) Firm Capacity Certification of Existing Generators

During the trial run, the Firm Capacity was calculated as per provisions of the Commercial Code for all the Legacy Generators except the Legacy Generators having bilateral contracts with Ex-WAPDA DISCOs. The procedure for determination of the Firm Capacity started with the collection of data on historical hourly availability for thermal based generation and reservoir based hydro generation and hourly Energy generation for renewable based generation units. Except the Generation Plants based on 1994 power policy, the hourly availability and hourly generation was available with CPPA-G. The hourly availability of Generation Plants based on the 1994 policy was estimated through the Daily Log Reports provided by the System Operator. Once the data was formulated, the Firm Capacities were calculated as per the formulas stipulated in the Commercial Code and its operational procedure.

Some important observations regarding the calculations of the Firm Capacity Certificates especially for the thermal based Generation Plants are provided below:

a) The availability of Legacy Generators based on 1994 power policy is not available on hourly basis and it was estimated through Daily Log Reports (DLR) provided by the System Operator.
b) There was no clear bifurcation between the actual available capacity and the capacity not available but being paid as per the forced outage allowance.
c) There are several practical issues in establishing the actual availability of Generation Plants due to the structure of the Legacy Contracts.
d) In majority of the Generation Plants, the availability information was available on Generation Plant basis instead of Generation Unit basis, therefore, the Firm Capacities for such Generation Plants have been determined on Generation Plant basis instead of Generation Unit basis.
e) For Generation Project procured bilaterally, no historical data on hourly basis was available, therefore the Firm Capacity for such Generation Plants was not calculated.
f) Due to these issues, it was considered appropriate to change the Firm Capacity determination mechanism for thermal based Generation Units from historical availability data to the annual/dependable capacity test in which CPPA-G has years of experience to certify the Capacity of Generation Plants in a scientific manner. Therefore, an amendment is proposed in the commercial code in this regard.
g) It was also observed that there are certain hours where the load on the System is higher than those hours that are included in the System Peak Hours, therefore, a recommendation has been proposed to alter the System Peak Hours.

Due to the observations as stipulated above, the Firm Capacity Certificates have not been issued and it is planned that these certificates will be issued once the revised mechanism is approved by the Authority.

viii) Issuance of Yearly Settlement Statements

As per approved Commercial Code, there were two components of the Yearly Settlement Statement:

a) Balancing Mechanism for Capacity (BMC)
b) Excess Losses of the Transmission Service Providers

a) Balancing Mechanism for Capacity (BMC)

The Balancing Mechanism for Capacity (BMC) was executed as per provisions stipulated in the Commercial Code. The following inputs were utilized for preparing the results of the Balancing Mechanism for Capacity:

a. **Hourly Metering and Load Shedding Data of DISCOs**

For the calculation of Critical Hours, hourly metering data of DISCOs was conveyed by MSP. Based on the metering data, hourly demand of DISCOs and transmission losses were calculated. The hourly profile of energy not served (Load Shedding) was also obtained from the System Operator. Accumulative hourly demand, hourly transmission losses and hourly load shed data is used for the calculation of critical hours.

It is important to highlight here that this is the responsibility of the System Operator to provide the Critical Hours to the Market Operator, however, during the trial run, the critical hours were identified by the Market Operator based on the information provided by the System Operator and MSP. The System Operator will be able to deliver this information in the future since all of the input characteristics necessary for determining Critical Hours are available.

b. **Generator's Availability and Energy Data**

For the calculation of capacity provided by the generators in critical hours, hourly availability data and load curtailment data of AREs was obtained from the System Operator. Apart from this, metering data of generator's CDPs was obtained from MSP. For thermal power plants and hydro with storage, availability data was used while for res and SPPs hourly injected energy and load curtailment data is utilized for the calculation of capacity provided by generators.

Similar to the Critical Hours, the calculation of the Capacity provided by the Generators during the Critical Hours is the responsibility of the System Operator, however, during the trial run, the Capacity provided by Generators during the Critical Hours was calculated by the Market Operator based on the information provided by the System Operator and MSP.

The System Operator will be able to deliver this information in the future since all of the input characteristics necessary for calculation of the Capacity provided by Generators during Critical Hours are available.

c. **Contract Data and Allocation Factors**

For crediting the capacity provided by generators during the Critical Hours to the respective Market Participants, the Capacity Contracts data is required. As there are only Legacy Generators whose Capacity shall be allocated to DISCOs and KE, therefore, the Capacity provided by these Generators was credited to the DISCOs and KE by using the allocation factors given in Table 4 of the Commercial Code and this action was executed successfully.

d. Metering data of DISCOs and KE

For the calculation of Capacity Requirements, Energy withdrawal data of each market participant is required in each Critical Hour. For this calculation, hourly metering data provided by MSP was utilized and this action was also executed successfully.

e. Efficient Reserve and Reserve Margin

The efficient level of reserves is the Capacity that is required to be installed in the system above the peak load, on long term basis, in order to minimize the total system costs. The Reserve Margin is the minimum level of Reserves that the System requires above peak load for security of the system. It is the responsibility of the System operator to determine the efficient level of reserves while developing IGCEP and for Reserve Margin it has to conduct certain studies. The Commercial Code also stipulates that till the time the System Operator determines the efficient level of reserve, a value of 35% shall be used and for Reserve Margin, a value of 10% shall be used.

As the System Operator has not yet established these values and will require capacity building to conduct the studies to determine theses, the transitory values have been used to execute this action.

f. Unitary Cost

The unitary cost of the Capacity is the investment cost of the most economic Generation Unit, capable of providing 1 MW of Firm Capacity during the Critical Hours. The reference technology will be the technology which minimizes the levelized fixed costs. The unitary cost of capacity will be equal to the levelized investment cost of the reference technology. It is the responsibility of the System Operator to determine this value and get it approved by the Authority along with IGCEP. The Commercial Code also stipulates that till the time the System Operator determines this value and gets it approved by the Authority, a value of 10,500,000 PKR/MW/Year shall be used.

Similar to the Efficient Reserve, as the System Operator has not yet established this value along with IGCEP and will require capacity building to conduct the studies to determine it, the transitory value has been used to execute this action.

Based on the assumption and limitations as stated above, the BMC was executed, and the results were shared with the relevant parties for feedback. The comments were responded to, and the Preliminary and Final Yearly Settlement Statements were issued. Based on the limitation as state above, it is also recommended that till the time the System Operator develops the capability to determine the values of the Efficient Reserve, Reserve Margin, and LIC and an infrastructure is available to determine the actual capacity withdrawn on coincidental basis, the trial run of the BMC shall be extended for further 3 years so that a basis for coincidental MDI for the Allocation Factors is established and the System Operator is also made capable to determine the inputs needed for the execution of the BMC. In this trial run of BMC, improvement will be suggested for further refinement of the process of BMC.

b) Calculation of Excess Losses for Transmission Service Providers

The Market Operator was unable to perform any simulations of this action because of non-availability of historical data. Further, it was analyzed during the trial run that the Market Operator will charge the actual losses to the Market Participants on hourly basis during the administration of the BME, however, the violation of the benchmark by any transmission service provider is a regulatory issue and is of bilateral nature between the Market Participants and the transmission service provider and hence the Market Operator shall not be involved in any such transactions. Therefore, this mechanism has been removed from the Commercial Code as a result of trial run recommendation.

ix) Calculation of Ex Ante Capacity Obligations

During the trial run, the Ex-Ante Capacity Obligations were determined by the Market Operator for all Ex-WAPDA DISCOs and KE as per provisions of the Commercial Code. The input data required for execution of this process was obtained in the following manner:

a. **Demand Forecast of the Market Participants:** This information was obtained from the respective Suppliers of Last Resort i.e., EX-WAPDA DISCOs.

b. **Existing Contracts of the Market Participants:** The Commercial Allocation Factors as stipulated in the Commercial Code were utilized to establish the share of the Capacity of each Ex-WAPDA DISCO in the pool of Legacy Generators. For K-Electric, its own Generators, its purchase from CPPA-G and its Contracts with IPPs were considered.

c. For the projects bilaterally procured by the Ex-WAPDA DISCOs, as no historical information on hourly basis was available and their Firm Capacities were not determined, therefore, their contracted capacities were taken as their Firm

Capacities. However, in future, as a Secured Metering System will be mandatory to be installed on such Metering Points, therefore, the Market Operator will be able to calculate their Firm Capacities as well.

d. **Future Contracts/Projects of the Market Participants:** For EX-WAPDA DISCOs, the committed projects in the IGCEP 2022 were considered as the future/planned projects for the Ex-WAPDA DISCOs. K-Electric provided separate information for its planned projects in the future.

e. **Capacity Obligations Percentage for each type of Market Participant:** The values given in the commercial code were utilized for this purpose. However, it was observed that the uncertainty margin for the 3rd and 4th year shall be linked with the growth rate of the demand forecast instead of using hardcoded values for which an amendment is proposed in the Commercial Code.

f. **Transmission Losses of NTDC:** This value was obtained from the latest tariff determination of NEPRA for NTDC.

g. **Reserve Margin:** It is the responsibility of the System Operator to determine the value of the Reserve Margin, however, the Commercial Code stipulates that till the time the System Operator determines the value of Reserve Margin, a value of 10% shall be utilized. Further, the System Operator will require capacity building to conduct studies to determine this value, the transitory value of 10% has been used to execute this action.

Based on the above input data, the Capacity Obligations were determined, results were shared with the Ex-WAPDA DISCOs and KE as per the procedure given in the Commercial Code.

x) Opening of Bank Accounts

This activity refers to the opening of bank accounts for market-related transactions for the MO in order to process the financial settlements.

RFP for opening bank accounts was prepared and issued to all banks, having long term credit ratings of 'A' and above. A pre-bid meeting was held on 10th January 2023 to answer queries of the banks. The last date for Bids submission was 18th January 2023.

Several meetings were held by the bid evaluation committee and clarifications were requested from Banks. The evaluation process took longer than expected as the correspondence between CPPA and the banks involved internal deliberations on both sides.

After the completion of the bid evaluation process, the LOI was finally issued to UBL for opening of accounts. The agenda for bank account opening was presented to the Board of Directors of CPPA-G in a meeting dated 30th March 2023 for approval. Issuance of resolution from Board of Directors CPPA-G is expected soon after which complete set of requisite documents will be submitted to the Bank for further processing and operationalization of MO bank accounts.

xi) Determination of the amounts for Security Cover and Settlement Guarantee Cover

The procedure of determination of the amounts of Security Cover and Settlement Guarantee Cover has been laid down in the Commercial Code. The amounts for both security covers have been determined by the MO.

Furthermore, a consultative session with DISCOs was held on 28th December 2022 wherein it was unanimously recommended by the DISCOs that in order to arrange funds for provision of Security Cover and Settlement Guarantee Cover, DISCOs may be allowed by the Authority to recover the Security Covers through consumer tariff and this matter will be taken up with the Authority as a recommendation of the test run. Therefore, it is recommended that the collection of these security covers may be allowed in the consumer end tariff of the DISCOs.

The details of the above-mentioned recommendation are attached at **Annexure III** (Minutes of Meeting of Consultative Session on CTBCM related Important Actions dated 28th December 2022) of this report.

xii) Development of Commercial Code Operating Procedure (CCOPs)

Commercial Code Operating Procedures (CCOPs) are standard set of documents that intend to cover and present additional details pertaining to specific requirements and contents of the Market Commercial Code.

All six CCOPs for Market Registration, Contract Registration, Metering, Firm Capacity, Capacity Obligation and Security Covers have been developed. The submission of CCOPs to the Authority via email has also been completed in November 2022.

8.2 TEST RUN TOOLS AND SYSTEMS

i) Completion of MMS Phase 1 Covering Monthly Settlements

This activity refers to the completion of MMS Phase 1. Population and stress testing of the developed modules (including enrollment, BME, ASC, Settlement Statements and Payments) with actual data has been completed.

Process optimization in the MMS Phase 1 in light of lessons learned during the process of first PSS issuance has also been completed and subsequently the project close-out document has been signed, which marks the official completion of this activity.

ii) Benchmarking of MMS with International Solutions

As per the approved test run plan, the benchmarking of the MMS with international solutions was envisaged in Feb 2023. However, keeping in view the development of Phase-II of MMS, it is more prudent to perform the benchmarking of the complete MMS system covering both phase I and II. Therefore, it is proposed that the timelines of the benchmarking may be extended for a period of one year.

iii) Setting up ERP Financial for Market Settlement

ERP is envisioned for the automation of financial settlement among the market participants as well as for calculation of MO fee. For smooth implementation of the ERP, a Future Process Model (FPM) was prepared and internally approved. The development of ERP has been completed as per the approved FPM and ERP financial module for market settlement has been operationalized.

iv) Development of MO Website

One of the most important actions under the CTBCM test run plan is the development of a separate website encapsulating the business of the Market Operator function of CPPA.

The development of the User Interface, Content Management System and the secured portal for Market Participants has been completed. Furthermore, the website is ready to "Go Live" on commencement of the Market.

v) Completion of Secured Metering System (NTDC, DISCOs)

In compliance with the provisions of the Grid Code, telecommunication of metering data was required which has been complied with since June 2022. Data Integration of MSP with MO has been completed as intended. Furthermore, the collection of data through Secured

Metering System (SMS) and the identification of Data Substitution Events has also been completed. Some data gaps have been identified pertaining to development of data collection, validation and substitution protocols which are being resolved by NTDC. Furthermore, unresolved issues on the part of the MSP also include staffing of data analysts & IT personnel to carry out the assignment in the desirable manner.

Moreover, the data substitution method of the Metering Data Management (MDM) solution does not comply with contemporary approaches of IT. The matter is being taken up with the vendor and a change request is to be initiated by NTDC.

It is pertinent to highlight some details of the SMS system. There are total number of 742 CDP metering points and on which telemetering enabled and grid code compliant meters have been installed. However, there are non-compliances with respect to backup metering system as only around 50% of the CDPs are telemetering enabled for backup meters.

Both the primary and the back-up meters (wherever installed) possess the capability of recording hourly metering data. The meter reading process as specified in the grid code is followed by MSP and the metering data from both the primary and backup meter is read for revenue calculations. In case the discrepancy between primary and backup meters is above the specified threshold, the final reading is determined through calibration and testing.

In order to meet the obligations as established in the revised Commercial Code, the MSP shall be obligated to undertake the following:

a. All Meters (Primary and Backup) at each Metering Point shall be equipped with the Secured Metering System and have the capability to transmit data remotely.
b. The current position is that there are 43 number of meters which are not equipped with SMS, although, hourly profile can be obtained electronically from such meters. These meters should be included in the SMS by the MSP before the start of the Market.
c. Meters equipped with SMS should be installed by the MSP at all Metering Points between PESCO and TESCO.
d. The MSP shall agree protocols with Market Participants and Service Providers regarding verification of the automated meter reading data.
e. The MSP shall reach an agreement with the Market Participants for shifting from the manual meter reading towards the automatic meter reading and stopping the legacy practice of signing the meter reading data by a committee.

vi) Marginal Price Application

The determination of the Marginal Price on system level is essential for settlement purposes in the CTBCM. So far, the Marginal Price Application has been developed and complete functionality of Marginal Price Application has been ensured in coordination with the SO.

The Marginal Price application has been operationalized and linked with SDXP for automatic data acquisition.

vii) Deployment of SDXP (Secure Data Exchange Portal)

SDXP is the data sharing portal maintained by the System Operator which is utilized for the real time data exchange between generators and SO. By July 2022, the Stress Testing of the SDXP Application was completed and all IPPs and NPCC are using the portal for relevant information exchange. SDXP is fully operational, and all requisite data is available on the portal.

The trial run on startup charges has not been completed because the System Operator has not provided any data on startup costs for Generators' starts for Ancillary Services. The System Operator may be directed to communicate this information to the Market Operator in the future.

viii) Development of Variable Cost Submission Portal

It was directed by the Authority to develop a portal for new IPPs which will enable them to share their variable cost information with the System Operator. The portal has been developed and was made operational in October 2022.

8.3 AWARENESS, CAPACITY BUILDING, TEST RUN SESSIONS AND REPORTS

i) Market Commercial Code Consultative Workshops and Test Run Reports

The 1st, 2nd and 3rd Consultative Sessions on Test Run Plan have been delivered in July, August and November 2022 respectively. Similarly, the monthly report for the months of June, July, August, September and October 2022 has also been furnished to NEPRA.

Furthermore, CPPA-G has initiated a weekly series of online sessions with the MIRADS of all DISCO and other interested entities for training and capacity building. A total number of 14 online sessions have been delivered from October 2022 till date.

A consultative session was also organized on 28th December 2022 amongst all DISCOs, KE and CPPA team on the following agenda items:

- Proposed Security Cover Requirement in Commercial Code for DISCOs
- Energy Imbalances in pool due to contracted quantities
- Recovery of Distribution Losses of DISCOs

Consequently, some key agreements and recommendations were framed as follows.

a) All participating entities agreed to provide funds for the Security Cover and Settlement Guarantee Cover as per the provisions of the Commercial Code when its due in future and not through Federal Government for covering the imbalances but through provision of funds through tariff.

b) It was also concluded unanimously that the recommendation of DISCOs to build the cost of Security Cover and Security Guarantee Fund in tariff, if not covered in existing tariff mechanism, will be accordingly taken up as a recommendation of the test run with the Authority.

c) It was unanimously concluded that the proposed mechanism for defining upper cap of allocation of energy is fair and be implemented to ensure market discipline.

d) It was unanimously concluded that the formula proposed in the Commercial Code will remain unchanged.

e) The Location of the metering point shall be duly considered while applying losses on the metered values and further clarity may be added in the Commercial Code specifically for the inter DISCO exchanges where meters are located at the 11 KV bus bars.

f) A consultation will be arranged amongst DISCOs and MSP by CPPA to resolve matters pertaining to metering and ownership of CDPs and application of losses.

The details of the above-mentioned recommendations to the respected Authority may be found in **Annexure III** (Minutes of Meeting of Consultative Session on CTBCM related Important Actions dated 28th December 2022) of the report.

ii) Awareness Sessions related to CTBCM applicable framework and Capacity Building

Successful Roadshow Workshops for sensitization of the CTBCM framework among market stakeholders were conducted so far in Lahore, Peshawar, Karachi, and Islamabad. Similarly, Electricity Market Professional (EMP) Program: Modules I, II and III were also delivered during June, July and August 2022 respectively. A follow-up EMP module is now scheduled in the coming months which will include demonstration of the Market Management System (MMS) and System Operator Data Exchange Portal (SDXP). Besides this, CPPA has been regularly offering and organizing multiple online sessions for power sector entities for awareness and capacity building of the market stakeholders.

Most recently, module 1 of Medium-Term Load Forecasting and Transmission Planning trainings have been successfully conducted in February and March 2023 respectively.

9- RECOMMENDATIONS

i) Definition of CDPs between TESCO and PESCO

Boundary metering points between TESCO and PESCO had not been defined as CDPs. Stakeholder coordination is in progress for demarcation of boundary between TESCO and PESCO, arrangement of meters and declaring the subject metering points as CDPs.

The matter was also discussed in the Chairman NEPRA led meeting with MD NTDC. Moreover, the Authority has directed both DISCOs to liaison closely with NTDC for the installation of these meters at the earliest vide letter no. NEPRA/Advisor (CTBCM)/LAD-10/18944 dated 4th October 2022.

Furthermore, in continuation of Authority's directions given vide letter No. NEPRA/Advisor (CTBCM)/LAD-07/8940 dated Oct 04th, 2022, for settlement of issues related to CDP between PESCO and TESCO, a meeting was held on 20th October 2022.

The issues regarding Metering Point Identification between PESCO and TESCO have now been divided into following four categories:

1. 132kv and 66kv Transmission Lines CDPs of TESCO with PESCO (14 Nos.)
2. CDPs (34 Nos. 11kv feeders) at TESCO's 132kv / 11kv Transformers installed in PESCO Grid Stations (07 Nos.)
3. CDPs at TESCO's 11kv feeders from PESCO's Transformers (18 Nos.)
4. CDPs of TESCO with PESCO at 11kv shared feeders (04 Nos.)

Total CDPs: 43

PESCO and TESCO have mutually agreed that the above-identified 43 boundary points between PESCO and TESCO will be considered for billing purposes. Furthermore, an interim arrangement has also been mutually agreed with the following terms.

1. 13 load profile enabled meters will be installed by TESCO on the designated CDPs.
2. 30 existing meters will be utilized as interim arrangement CDP meters.
3. 43 meters will be tested and sealed in place in the presence of PESCO, TESCO and MSP NTDC.
4. One of existing energy meters (Make: ISKRA, Sr No. 76025921) Installed at HPS WAPDA Gomal Zam – Wana is being re designated as WAPDA to TESCO CDP.
5. Both PESCO and TESCO shall report the metering data from the above 43+01 Nos. CDPs every month to CPPAG and NTDC within the timelines provided for in Market Commercial Code i.e., D+02.

It is recommended to the Authority that PESCO and TESCO may be directed to provide a plan for the complete procurement and installation of meters, both primary and backup, on an immediate basis to resolve the issue.

ii) Metering Data Authentication

There are total of 742 CDPs and all have been equipped with telemetering enabled and grid code compliant primary energy meters. However, there are non-compliances with respect to backup metering system as only around 50% of the CDPs are telemetering enabled. It is recommended that a plan may be acquired from MSP for installing grid code complaint revenue meters at backup metering points (where applicable) and integration of its communication mechanism with MDM.

iii) Strengthening of MIRAD

During the test run, it was observed that in some of the DISCOs including HESCO, QESCO and IESCO, the placement of DG MIRAD is still not on permanent basis. Further, only a few months are left in the retirement of DG MIRAD MEPCO. SEPCO, MEPCO and QESCO also require strengthening of the MIRAD departments by completing the hiring process against the sanctioned vacant positions.

MIRADs should ensure strict compliance with SOPs which are already developed or will be developed in the future to govern the routine operations of the department in a competitive market regime in order to handle the matters efficiently.

iv) Submission of SP Admission Applications by NTDC

It is apprised that CPPA has shared the template of Service Provider admission application with NTDC in September 2022 for submission of duly-filled applications to the Market Operator for further processing. Subsequently, several reminders were also issued and CPPA is continuously pursuing NTDC for the submission of their admission application. However, this action is still pending on the part of NTDC.

It is recommended that the Authority may direct NTDC to ensure submission of its admission application on priority basis.

v) Live demonstrations of Market related IT systems & applications to NEPRA Market team by respective entities

It is recommended to the Authority that NEPRA Market Team may undertake live demonstrations of the market related IT systems and application developed by the power sector entities. This will enable NEPRA to validate the date completeness, processing capabilities and optimized functionality of IT systems & applications as required for the effective market operations by the respective entities.

vi) Submission of detailed report on the proposed Regulatory Framework changes by CPPA to NEPRA

The associated regulatory framework for CTBCM has been prepared by the Authority through notification of various market-related regulations, whereas some regulatory documents are still in the process of regulatory approval. In accordance with Section H Part (c) of the MO

License Determination, CPPA-G is required to submit "recommendations, if any, regarding the amendments in any other applicable document".

To comply with this direction, a comprehensive report will be furnished in due course of time. This report will outline the recommendations for proposed amendments to the regulatory framework and will be submitted to the Authority for consideration.

vii) Proposed Transitory Mechanism for Allocation of Capacity

A consultative session with Chief Financial Officers, Finance Directors and Director General MIRADs of all DISCOs was conducted on 4th October 2022. In the session, consensus was developed on charging mechanism of capacity based on allocation factors and is recommended to the Authority as follows:

"The Commercial Code approved allocation factors are to be used by DISCOs for planning of future bilateral capacity procurement and imbalances under CTBCM.

Furthermore, charging of capacity to DISCOs should be based on following transition:

a. A transition of up to three (03) years be provided for payment of capacity charges. During this transition, the capacity will continue to be charged in accordance with the existing practice.

b. Three years will be the maximum time for the transition, however, based on the readiness of the system and the directions of the Authority, the shift may be made earlier. It was also discussed that a regulation may also be required by NEPRA that will specify the methodology providing the details of calculating contributions of DISCOs peaks to the system peaks.

c. As soon as the coincidental MDI based charging mechanism is established or implemented as per direction of NEPRA, the allocation table in the Market Commercial Code be updated based on shift to co-incidental MDI system contributions. It was agreed that this updated allocation table will be used for (a) payment of capacity charges by DISCOs for legacy generation and (b) planning of new bilateral capacity."

The details of the above-mentioned recommendations to the Authority may be found in Annexure II (Minutes of Meeting of Consultative Session on Allocation Factors and Charging Mechanism of Capacity dated 11th October 2022) of the report.

viii) Building the cost of SC and SGC in tariff mechanism

In light of the consultative session held on 28th December 2022 and subsequent joint proposition by the DISCOs, it is recommended to the Authority that DISCOs may be allowed to recover the amount for Security Covers through consumer tariff.

The details of the above-mentioned recommendation are attached at **Annexure III** (Minutes of Meeting of Consultative Session on CTBCM related Important Actions dated 28th December 2022) of this report.

ix) Capacity building of the System Operator

The System Operator has not determined the parameters required for execution of the BMC such as Reserve Margin, Efficient Reserves and Levelized Investment Cost (LIC) of Reference Technology. Currently the System Operator doesn't have the requisite capability to determine these values. This will require some time for the System Operator to undertake the relevant capacity building to conduct studies to determine these values. Therefore, the System Operator may be directed to undertake the necessary capacity building in this regard.

ANNEX I-A: CTBCM TEST RUN PLAN

A) MARKET COMMERCIAL CODE

#	Action	Responsible Entity	Supporting Entity	NEPRA Deadline	Actions under Status
1	**Establishment of CCRP Panel**	**CPPA-MO**	**DISCOs/NTDC/SHs**		
	Seeking Nominations for CCRP	CPPA-MO	DISCOs/NTDC	30-Sep-22	Completed
	Establishment and Notification of CCRP	CPPA-MO	DISCOs/NTDC	30-Oct-22	Completed
2	**Preparation of Merit Order on shorter period***	**CPPA-SPA, NTDC-SO**	**CPPA-MO**		
	Consultation between CPPA-SPA and NPCC	CPPA-SPA	CPPA-MO	30-Jun-22	Completed
	Discussion with IPPs completed	CPPA-SPA, NTDC-SO	CPPA-MO	30-Jul-22	Completed
	Preparation of Merit Order on daily basis started	NTDC-SO	CPPA-MO	30-Nov-22	Completed
3	**Enrollment of Market Participants and Service Providers**	**CPPA-MO**	**NTDC/DISCOs**		
	Development of MPA/SPA and its submission to NEPRA	CPPA-MO	NTDC/DISCOs	30-Jun-22	Completed
	Enrolment Application by DISCOs and NTDC and signing of MPAs/SPAs	CPPA-MO	NTDC/DISCOs	30-Sep-22	**In Progress**
4	**Contract Registration**	**CPPA-MO**	**CPPA-SPA**		
	Collection of data for commercial allocation of capacity among DISCOs	CPPA-MO	CPPA-SPA	30-Jun-22	Completed
	Registration of Legacy Contracts in MMS	CPPA-MO	CPPA-SPA	30-Jun-22	Completed
	Contract Registeration Completed	**CPPA-MO**	**CPPA-SPA**	**30-Jun-22**	Completed
5	**Charging of Capacity based on Allocation Factors**	**CPPA-SPA**	**CPPA-MO**		
	CPPA-SPA calculate charges for DISCOs/KE based on Allocation Factor instead of MDI	CPPA-SPA	CPPA-MO	30-Jul-22	Recurring
6	**Execution of BME and Settlement Statements**	**CPPA-MO**	**NTDC/KE**		
	Calculate balancing mechanism for energy (BME) and additional market charges to prepare monthly Settlement	CPPA-MO	NTDC/KE	Every Month	Completed
	Issuance of Preliminary and final Settlement Statements	CPPA-MO	NTDC/KE	Every Month	Recurring
7	**Firm Capacity Certification of Existing Generators**	**CPPA-MO**	**CPPA-SPA/NTDC**		
	Receive data from relevant entities	CPPA-MO	CPPA-SPA/NTDC	30-Jul-22	Completed
	Process data and Issue certificates	CPPA-MO	CPPA-SPA/NTDC	30-Aug-22	Completed

8	**Issuance of Yearly Settlement Statement**	**CPPA-MO**	**-**		
	Execute BMC for previous year	CPPA-MO	-	30-Sep-22	
	Calculate excess transmission loss for previous year	CPPA-MO	-	30-Sep-22	
	Issue Preliminary and final Yearly Settlement Statement	CPPA-MO	-	30-Nov-22	
	Check ex-post compliance with Capacity Obligations	CPPA-MO	-	30-Nov-22	
9	**Calculation of Ex-ante Capacity Obligations**	**CPPA-MO**	**DISCO/KE/CPPA-SPA**		
	Received data from DISCOs and KE	CPPA-MO	DISCO/KE/CPPA-SPA	30-Oct-22	
	Process data and calculate Obligation	CPPA-MO	DISCO/KE/CPPA-SPA	30-Nov-22	
	Convey results to DISCOs and KE	CPPA-MO	DISCO/KE/CPPA-SPA	30-Nov-22	
10	**Opening of Bank Accounts**	**CPPA-MO**	**CPPA-SPA**		
	Opening of Bank Accounts for Market Operations	CPPA-MO	CPPA-SPA	30-Aug-22	**In Progress**
11	**Determination of the amounts for Security Cover and Settlement Guarantee Fund**	**CPPA-MO**	**NTDC/NPCC/DISCO/KE**		
	Determination of the amounts for Security Cover and Settlement Guarantee Fund	CPPA-MO	NTDC/NPCC/DISCO/KE	30-Oct-22	
12	**Development of ccops**	**CPPA-MO**	**DISCO/KE**		
	Development of the ccops (Market and Contract Registration, Metering, Firm Capacity, Capacity Obligation, Security Covers)	CPPA-MO,NTDC	DISCO/KE	30-Aug-22	
	Submission to Authority for review	CPPA-MO,NTDC	DISCO/KE	30-Nov-22	

B) TEST RUN TOOLS & SYSTEMS

#	Action	Responsible Entity	Supporting Entity	NEPRA Deadline	Status
1	**Completion of MMS Phase 1 covering monthly settlements**	**CPPA-MO**	**NTDC**		
	Populating and Testing of the developed modules (enrollment, BME, ASC, Settlement Statements and Payments) with actual data and stress testing	CPPA-MO	NTDC	30-Jul-22	[illegible]
	Identification of bugs and their removal	CPPA-MO	NTDC	30-Sep-22	Completed
2	**Development of MMS Phase 2 covering all transactions***	**CPPA-MO**	**NTDC**		
	Development of new Modules (BMC, Contract Management, Firm Capacity Certification, Capacity Obligation, Security Cover Calculation, Complaint Management	CPPA-MO	NTDC	30-Oct-23	[illegible]
	Testing of the modules with real data	CPPA-MO	NTDC	30-Feb-24	-
	Identification of bugs and their removal	CPPA-MO	NTDC	30-Aug-24	-
3	**Benchmarking of MMS with international solutions***	**CPPA-MO**	-		
	Benchmarking with NYISO/PJM Market Management System	CPPA-MO	-	30-Feb-23	Extension Requested
4	**Setting up ERP Financial for Market Settlement**	**CPPA-MO**	**CPPA-SPA**		
	Configuration of ERP Financials	CPPA-MO	CPPA-SPA	30-Aug-22	Completed
	Integration with MMS and testing with actual data	CPPA-MO	CPPA-SPA	30-Oct-22	Completed
5	**Development of MO Website**	**CPPA-MO**	**CPPA-SPA**		
	Development of MO website for publishing market results	CPPA-MO	CPPA-SPA	30-Nov-22	Completed
6	**Completion of SMS (NTDC, DISCOs)**	**CPPA-MO**	**NTDC/KE**		
	Coordination for Collection of 100% data through SMS and its transmission to Market Operator	CPPA-MO	NTDC/KE	30-Jun-22	[illegible]
	Coordination for Development of the data collection, validation and substitution protocols	CPPA-MO	NTDC/KE	30-Sep-22	[illegible]
7	**Development of SMS (KE)***	**KE**	**CPPA-MO/NTDC**		

	Collection of 100% data through SMS and its transmission to Market Operator	KE	CPPA-MO/NTDC	KE Integration Plan	-
	Adoption of the data collection, validation and substitution protocols	KE	CPPA-MO/NTDC	KE Integration Plan	-
8	**Marginal Price**	**NPCC**	**CPPA-MO/KE**		
	Complete functionality of the Marginal Price application	NPCC	CPPA-MO/KE	30-Aug-22	
	*Integration of KE into the application**	NPCC		KE Integration Plan	-
9	**Deployment of SDXP**	**NPCC**	**CPPA-MO/KE**		
	Stress testing of the SDXP Application and removal of bugs	NPCC	CPPA-MO/KE	30-Aug-22	
	*Integration of KE System into the SDXP**	NPCC	CPPA-MO/KE	KE Integration Plan	-
10	**Development of Variable Cost Submission Portal***	**NPCC**	**CPPA-SPA/CPPA-MO**		
	Development and Testing of Portal	NPCC	CPPA-SPA/CPPA-MO	30-Aug-22	
	Training of IPPS on the portal	NPCC	CPPA-SPA/CPPA-MO	30-Aug-22	
	Go Live	NPCC	CPPA-SPA/CPPA-MO	30-Aug-22	

C) **AWARENESS, CAPACITY BUILDING, TEST RUN SESSIONS & REPORTS**

#	Action	Responsible Entity	Supporting Entity	NEPRA Deadline	CTBCM Test Run Plan-Capacity Building Status
1	**Market Commercial Code Consultative Workshops and Test Run Reports**	**CPPA-MO**	**All power sector entities**	**Nov-22**	
	First Consultative Workshop-Under EMP M-II	CPPA-MO	All power sector entities	30-Jul-22	
	Second Consultative Workshop	CPPA-MO	All power sector entities	30-Sep-22	
	Third Consultative Workshop	CPPA-MO	All power sector entities	30-Nov-22	
	Monthly Test Run Reports and final consolidated Test-Run Report	CPPA-MO	All power sector entities	30-Nov-22	
2	**Awareness Sessions related to CTBCM applicable framework and Capacity Building**	**CPPA-MO**	**All power sector entities**	**Continue**	
	Awareness sessions for Licensees, BPCs, Investors, Industries and other Stakeholders.	CPPA-MO	All power sector entities	30-Nov-22	
	Trainings for power sector entities related to CTBCM policy and regulatory frameworks and capacity building.	CPPA-MO	All power sector entities	Continue	

ANNEX I-B: SPECIFIC DIRECTIONS

A) SPECIFIC DIRECTIONS

#	Action	Responsible Entity	NEPRA Deadline	Status
	Specific Directions of the Determination	**CPPA-G**		
1	*Develop a Robust IT Strategy*	CPPA-G	30-Jun-22	[illegible]
2	*Designate a Senior Office from Market Operations that shall act as a primary focal person with the Authority.*	CPPA-G	30-Jun-22	[illegible]
3	*Functional Segregation of MO & SPA*	CPPA-G	30-Nov-22	[illegible]
4	*Monthly Reports on Dry Run to NEPRA*	CPPA-G	Recurring	[illegible]
5	*CPPA-G to coordinate with DISCOs, NTDC, KE, SO & others for test run plan of Market Commercial Code & other activities.*	CPPA-G	Recurring	[illegible]
6	*Submission of SPA Registration Application, Draft Agency Code and Roadmap plan for legal segregation of MO and SPA.*	CPPA-G	30-Sep-22	[illegible]

ANNEX I-C: PROPOSED AMENDMENTS IN COMMERCIAL CODE

Table 1. Proposed Amendments in the approved Commercial Code

Sr. No.	Description of the Proposed Modification	Explanation	Source
	Technical		
1.	**Chapter 18. Miscellaneous, Complementary and Transitory Provisions** **Sub-Section 18.2.5. Methodology and Factors for Allocation of Legacy Contracts** i. The above Sub-Section of the approved Commercial Code stipulates that the Commercial Allocation Factors for allocation of the Legacy Contracts among DISCOs shall be based on average of last three year's capacity invoices of the DISCOs, however, the Commercial Allocation Factors given in the approved Commercial Code are based on the average of last three-year energy invoices of DISCOs. Therefore, the factors given in Table-8 of the Commercial Code regarding Commercial Allocation of the DISCOs need to be updated. Further, in order to update the table, it is recommended to include the values of most recent past three fiscal years i.e. FY 2019-20, FY 2020-21 and FY 2021-22. ii. Table 8 has been deleted from the Commercial Code.	i. After approval of the Commercial Code and during the test run, consultative sessions were held with the DISCOs. During a consultation session, it was identified that although Market Commercial Code stipulates that the historical capacity invoices shall be used to calculate the Commercial Allocation Factors, however, the factors given in the approved Commercial Code were based on energy invoices data and this requires correction. ii. During the trial run, it was observed that providing hardcoded values in the Commercial Code, as stipulated in Table 8, is not be appropriate because it is an operational issue and it is a living table based upon yearly review and Updation based on parameters and methodology provided in the commercial code. Hardcoding of the values may not be possible because any change in the commercial code has to be approved by the Commercial Cod Review Panel which will hamper the process. Because of this reason, the Commercial Code shall provide the principles for determination of such values and the Market Operator shall be responsible to publish such data	Consultative Session

iii. Furthermore, the share of MDI's that is agreed between PESCO and TESCO has been recently revised which requires due consideration while calculating the allocation factors.

based on the principles of the Commercial Code. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.

iii. Due to absence of meters between PESCO and TESCO, there was no specific parameter to be used to share the MDI between PESCO and TESCO. However, recently the mechanism has been revised by both the DISCOS from the historical practice which has resulted in greater share of the MDI to TESCO as compared to the historical pattern. In order to address this issue, the most recent percentage share has been used to update the Commercial Allocation Factors of PESCO and TESCO in the allocation table of the Commercial Code.

2. **Chapter 18. Miscellaneous, Complementary and Transitory Provisions**
Sub-Section 18.2.5. Methodology and Factors for Allocation of Legacy Contracts

i. Additional provisions shall be inserted in the approved Commercial Code to explain that the Commercial Allocation Factors shall be used for the following three purposes:
A. Planning
B. Energy Imbalances
C. Capacity Invoices

i. During the trial run, it was observed that the historical payments by the DISCOs to CPPA-G for their Capacity payments are based on their non-coincidental MDIs which has many issues. Therefore, it is not appropriate to charge the Imbalances to DISCOs based on a factor which is calculated on a data that has no sound basis. However, the payments for Energy are calculated based on the actual Energy withdrawn by the DISCOs as measured by the Commercial Metering System. Therefore, the Allocation Factor based on

	The Commercial Allocation factors calculated on historical Capacity invoices data shall be used for planning purpose only. The Factors already calculated on historical Energy data in invoices shall be used for the calculation of Imbalances. For Capacity Invoices, the following transition shall be adopted for calculation of the Allocation Factors: a. At least three (3) years of coincidental MDI data for calculation of the Allocation Factors b. Installation of Commercial Metering System as per provisions of the Commercial Code and Grid Code on all Metering Points especially the Metering Points between PESCO and TESCO Once the Allocation Factors are calculated on the coincidental MDI data, then the same factors shall be used for all of the above three purposes.	historical Energy invoices data is a better option to be used to calculate the Imbalances of the DISCOs. ii. This amendment is proposed to reflect the agreement that was reached during the consultative sessions held with the Ex-WAPDA DISCOs.	
3.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Clauses 6.5.2.2. (b1) and (b2), which are related to charging of compensation for Must Run Generation and Ancillary Services to BPCs and Competitive Suppliers, need to be amended to eliminate the responsibility of the Competitive Supplier to pay for the share of the BPCs which are Market Participants.	During the trial run, it was analysed that the formula produces undesired results when a Fixed Quantity Supply Contract is signed between a competitive supplier and a BPC which is a Market Participant. The Competitive Supplier is charged extra, and the same amount is paid to the BPC which is not an intended transaction. As per the design of the Commercial Code, each Market Participant is responsible for payment of compensation for the Ancillary Services and Must Run Generation for its own demand or the demand it represents in the market. Therefore, in order to address this issue, this amendment is being proposed.	Test Run Implementation
4.	**Chapter 5. Balancing Mechanism for Energy**	During the trial run, it was observed that at certain Generation Plants, meters are installed on the	

	A new section (5.2 Calculation of Total Generation and Back-Feed Energy of The Generation Plants) shall be inserted in Chapter 5 to calculate the Generation and back-feed Energy of the Generation Plants.	transmission/distribution lines instead of the Generation Units. Therefore, certain additional calculations are required to be performed to calculate the actual Generation or Back-feed Energy of the Generation Units. In order to solve this situation, calculation methods have been formulated, tested and incorporated into the Market Management System (MMS) and the same are required to be incorporated in the Commercial Code. For this purpose, amendments were required in Chapter 5 which are incorporated in the revised Commercial Code submitted along with this report.	Test Run Implementation
5.	**Chapter 5. Balancing Mechanism for Energy** Section 5.3.2 Calculation of Total Demand. The above section needs to be amended to change the calculation of total demand from the current formula to total generation minus transmission loss.	During the trial run it was observed that due to certain power flows in the transmission network, the Total Demand cannot be calculated through the method stipulated in approved Commercial Code. The flow from the distribution network towards transmission network through Generation Plants were not envisaged at the time of drafting of the Commercial Code. The real time data on hourly basis showed such flows and rendered the original formula not matching the situation on ground and therefore required amendment. The alternative formula for the calculation of the total demand has been incorporated in the MMS and tested which is based on the total generation minus the transmission loss. The same formula is incorporated in the revised Commercial Code submitted along with this report.	Test Run Implementation
6.	**Chapter 1. General Conditions** The definition of System Peak Hours is modified in such a manner that instead of using one continuous block of 11 hours (from 10 a.m. To 9 p.m.) As stipulated in the approved Commercial Code, now two blocks covering	During the trial run, detailed analysis of load profiles of last three years were conducted and during this exercise, it was observed that the system load generally peaks twice in a day, both during the day and night hours. Therefore, instead of using one continuous block of 11 hours (from 10	Consultative Session

	day (1200 hrs to 1700 hrs) and night hours (2200 hrs. To 0100) are used.	a.m. To 9 p.m.) As defined in the approved Commercial Code, it needs to be revised to two blocks covering both day and night hours as system peak occurs both during the day as well as night. The new definition which is included in the revised commercial code is as follows: "System Peak Hours mean 11 hours on daily basis included in the period from 1200 hrs to 1700 hrs and 2200 hrs to 0100, all inclusive, hrs in the months of June, July, August and September"
Clarifications and Typos		
7.	**Chapter 1. General Conditions** Sub-Section 1.2.2. Interpretation Insertion of Sub-Clause (i) in Clause 1.2.2.2. The insertion of above Sub-Clause (i) specifies the number of digits (4 digits) up to which any fraction in calculations to be performed under the Commercial Code shall be rounded off.	During the trial run, it was observed that in the market settlement process, there are several calculations are to be performed in which different ratios/fractions are calculated. The number of digits up to which a decimal figure shall be rounded off has an impact on the final results. Therefore, it is required that the Commercial Code specifies the number of digits up to which the value of a ratio is rounded off. After analysing the results during the trial run, it was deemed appropriate that decimal figures should be rounded off to four digits and the same is included in the revised Commercial Code being submitted along with this report.
8.	**Chapter 1. General Conditions** Sub-Section 1.2.2. Interpretation Insertion of Sub-Clause (j) in Clause 1.2.2.2. A new Sub-Clause (j) has been inserted in the approved Commercial Code in order to address the issue of difference (if any) arising between the total Amounts Payable and Amounts Receivable in any Settlement Period.	In an ideal scenario, during any Settlement Period, the total Amounts Payable and Amounts Receivable shall always be equal, however, during the trial run, it was observed that in some Settlement Periods, the final Amount Payable and Amount Receivable is not exactly equal due to the rounding off of certain ratios (as discussed in amendment proposed at Sr. No. 6 above). This difference is very small and is always less than Rs. 5, however, it still exists.

		In order to resolve this issue, Sub-Clause (j) has been inserted in the revised Commercial Code submitted along with this report which stipulates that such difference shall be limited up to Rs. 10 in any Settlement Period and the same shall paid/retained and adjusted in the Market Operator Fee.
9.	**Chapter 1. General Conditions** Sub-Section 1.3.1. Commercial Code Review Panel A new Clause 1.3.1.10 has been inserted in the above referred Sub-Section of Chapter 1 of the approved Commercial Code which specifies the procedure for nomination of the members of Commercial Code Review Panel (CCRP) representing Category of Market Participants where no association of the members of that Category exists, and the number of Market Participants registered in such Category is less than five.	During the trial run, it was identified that the approved Commercial Code stipulates that in case of certain Market Participants such as IPPs, VREs and BPCs, where the associations of such Market Participants do not exist, nominations are to be sought by the Market Operator from 'enrolled' Market Participants, which also currently do not exist. Therefore, in order to address this issue, a new Clause 1.3.1.10 is inserted in the revised Commercial Code submitted along with this report. The newly inserted Clause stipulates that in absence of Associations and enrolled Market Participants of any particular Category, the representatives of such category shall be nominated by the Authority.
10.	**Chapter 1. General Conditions** Sub-Section 1.2.1. Definitions The definition of the Legacy Contracts is amended as follows: i. **"Legacy Contract -CPPA-G"** means: a. A PPA or EPA (including International Interconnection Agreements (import/export), off-take arrangements with WAPDA and NTDC) which are signed or administered by the CPPA-G before the CMOD. b. A PPA or EPA (including International Interconnection Agreements (import/export) to	During the trial run, the treatment of Legacy Contracts in the Market was discussed at length at it was deemed necessary that clarity in the definition of Legacy Contracts is needed due to the following reasons: i. The definition should be clear regarding the Legacy Contracts of EX-WAPDA DISCOs and KE because both have different treatment in the Commercial Code i.e. The Legacy Contracts of EX-WAPDA DISCOs are commercially allocated to them while the Legacy Contracts of KE will continue to belong to KE only.

	be signed by CPPA-G in the future for any other projects which are considered committed for EX-WAPDA DISCOs in the latest IGCEP approved by the Authority before CMOD. ii. **"Legacy Contract -KE"** means a PPA or EPA signed and administered by KE before the CMOD. iii. **"Legacy Contract-DISCOs"** means a PPA or EPA signed or administered by any of EX-WAPDA DISCO before the CMOD.	ii. It was considered appropriate that the contracts for the committed projects for Ex-WAPDA DISCOs that have been considered in the latest IGCEP, approved by the Authority before CMOD, should be signed and administered by the Special Purpose Agent (SPA) as the investors against these projects have secured their finances and risks as per the single buyer regime. It is also pertinent to highlight that in the latest IGCEP 2023, criteria for committed projects was approved by the CCI as part of the assumption set. Therefore, as per the above explanation, the definition of the Legacy Contracts has been revised and incorporated in the revised Commercial Code submitted along with this report.
11.	**Chapter 1. General Conditions** Sub-Section 1.2.1. Definitions The definition of the Congested Zone is amended as follows: "Congested Zone" means an area in the Transmission Network, established as per Sub-Section 6.2.1of this Code, which consists of multiple Congested Areas and can be considered as an independent network having interconnections with other independent networks.	In the consultative sessions held during the trial run, it was highlighted that a clear definition of the Congested Zone will add clarity to the clauses of the Commercial Code. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.
12.	**Chapter 2. Enrolment of Market Participants and Service Providers** Sub-Section 2.5.1. Withdrawal by a Market Participant The Clause 2.5.1.3 has been revised and text regarding treatment of Security Cover and Settlement Guarantee	During the trial run, it was observed that when a Market Participant withdraws its enrollment in the middle of any Settlement Period, especially the yearly Settlement Period, then there shall be provisions in the Commercial Code to retain its Security Covers and Guarantee Amount

	Cover upon withdrawal of a Market Participant has been inserted in order to ensure that all current and future liabilities of such Market Participant are fulfilled before returning its Security Covers and Guarantee Amount. The same amendment has been made in the case of termination of a Market Participant (Chapter 16) as well as return of Security Cover and Settlement Guarantee Cover as envisaged in Chapter 13.	till all liabilities are discharged by the Market Participant. In order to address this issue, new text in Clause 2.5.1.3 has been inserted in the revised Commercial Code, submitted along with this report, which stipules that the Market Operator shall withhold the Security Cover and Guarantee Amount of the Market Participants till the time all the liabilities of such Market Participant are discharged.	
13.	**Chapter 3. Contracts and Contract Registration** In Clause 3.4.2.2 of the approved Commercial Code, further clarity is added that if a Market Participant signs multiple Contracts on a single Metering Point, the priority between different Contracts shall also be clearly established at the time of registration of such Contracts.	In order to add further clarity regarding the registration of multiple Contracts linked to a single Metering Point, this provision has been added in the revised Commercial Code submitted along with this report.	Test Run Implementation
14.	**Chapter 3. Contracts and Contract Registration** Section 3.3. Characteristics of Standardized Contracts and Section 3.4. Customized Contracts The above referred Sections in the approved Commercial Code provides flexibility that the compensation for Must Run Generation and Ancillary Service determined for a Generator can be paid either to the Generator or the buyers in the Contracts of such Generator. This provision requires amendment as it creates complications in devising formulas for all the possible scenarios. It is more practicable that, initially, only the Generation Following Contracts shall have the provision of paying the compensation for Must Run Generation and Ancillary Service to the buyers in the Contract of a Generator for which such compensation	During the development of the Market Management System, difficulties were faced in solving different scenarios of the transactions where the compensation for Must Run Generation and Ancillary Services can either be paid to the Generator or to the buyers in the Contracts of such Generator. In order to address this issue, it was considered appropriate that initially only Generation Following Contracts shall allow payment of such compensation to the buyer. All other types of Contracts involving a Generator shall have provisions for payment of compensation for Must Run Generation and Ancillary Services to: 1. The Generator where the Generator is itself enrolled as a Market Participant; or	Test Run Implementation

	is determined. In rest of the Contracts, it shall be paid to the respective Generator or its representative Market Participant.	2. The Market Participant representing the Generator where the Generator is not required to be enrolled as a Market participant as per provisions of the Commercial Code. In order to address this, the relevant provisions of these referred Sections have been amended in the revised Commercial Code submitted along with this report.	
15.	**Chapter 4. Commercial Metering System** A new Sub-Section (4.3.3. Data Provision to the Market Operator) has been inserted in the approved Commercial Code which lays down specific deadlines for the Metering Services Provider (MSP) to provide data on daily basis as well as establishes a deadline (2 Business Days) at the end of each month for the MSP to provide complete data (either from SMS, Local Meter reading or estimations) to the Market Operator for monthly Settlements.	During the trial run, it was observed that in the approved Commercial Code, it is stipulated that the MSP shall collect the data on daily basis through its Secured Metering System (SMS), however, no clear deadline was set for transferring this data to the Market Operator. In order to address this issue, the revised Commercial Code submitted along with this report, includes provisions which sets clear deadlines for the MSP to submit data to the Market Operator on daily as well as monthly basis. This deadline will enable the Market Operator to timely issue the Settlement Statements.	Test Run Implementation
16.	**Chapter 4. Commercial Metering System** Sub-Section 4.3.3. Data Verification by the Market Operator and its Substitution In the title of the above referred Sub-Section of the approved Commercial Code, the words "and its substitutions" have been removed. Further, this Sub-Section has also been renumbered as Sub-Section 4.3.4 in the revised Commercial Code. Additionally, in Clause 4.3.3.2 of the approved Commercial Code (now Clause 4.3.4.2) the words	The substitution of the metering data is the responsibility of the Metering Service Provider and not the Market Operator. Therefore, it was deemed necessary to amend the title of Sub-Section 4.3.3 in the revised Commercial Code submitted along with this report to avoid any confusion of responsibilities between the Market Operator and the Metering Service Provider.	

	“provided by the Metering Service Provider” have been added after the words “substituted values”.		
17.	**Chapter 5. Balancing Mechanism for Energy,** **Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** **Chapter 18. Miscellaneous, Complementary and Transitory Provisions** In Chapter 5, Chapter 6 and Chapter 18, new provisions have been inserted to establish a deadline for the System Operator to submit the final data regarding the Peak Capability/Availability of Generation Plants, Marginal Prices, Must Run Generation and Ancillary Services as required under the Commercial Code on daily basis as well as a confirmation regarding finality of the data within two Business Days at the end of each month.	During the trial run, it was observed that most of the data provided by the System Operator to the Market Operator on daily basis is dependent on the metering data of the MSP which may not be finalized on daily basis due to several constraints such as communication failure, meter failure etc. Therefore, besides providing data on daily basis to the Market Operator for analysis purposes, the System Operator shall submit the final data to the Market Operator for using in the Settlement process by the Market Operator within 2 Business Days at the end of each month. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	
18.	**Chapter 5. Balancing Mechanism for Energy** i. In Clause 5.5.1.1, the words “as per procedure given in Appendix 1” are omitted. **ii.** A new Clause 5.5.1.2 which reads as: “Within eighteen (18) months from the approval of this Code, the System Operator shall, in collaboration with the Market Operator, make and submit to the Authority for approval a methodology for determining the hourly System Marginal Price. Until such methodology is approved, the procedure included in Appendix 1 shall be used, as an interim measure, for calculation of the System Marginal Price.”	i. During the trial run, it was observed that Appendix 1, which was proposed as an interim measure only in the Commercial Code submitted by the Market Operator. However, the final version of the Commercial Code gave the impression that this Appendix 1 is a permanent feature of the Commercial Code. In order to address this issue, amendment has been made in Clause 5.5.1.1 so that this Appendix remains as an interim procedure for determination of the System Marginal Prices till the time the System Operator develops a detailed methodology and the same is approved by the Authority.	Test Run Implementation

		ii. The procedures given in Appendix 1 is a simplified method for determination of System Marginal Price and needs further deep analysis and also requires historical data for actual operation of the power system. Therefore, it was deemed necessary that 18 months should be allowed from the approval of the revised Commercial Code to test the system and come up with a detailed methodology for determination of the System Marginal Price by the System Operator. In light of the above, this amendment is included in the revised Commercial Code submitted along with this report.	
19.	**Chapter 5. Balancing Mechanism for Energy** Section 5.4: Consideration of Transmission Losses i. Further clarity is added in the above referred Section regarding the interconnection points located at the boundary of a Transmission Licensee. ii. The transmission loss is calculated as the difference between the Energy injected into the network of the Transmission Licensee and the Energy withdrawn from the network of such Transmission Licensee as reported by the Metering Service Provider. It is noted here that this is a clarification not an amendment.	i. During the trial run, it was observed that Section 5.4 needs further clarity regarding the interconnection points to avoid any confusion. ii. During the trial run, it was observed that the Metering Service Provider (NTDC) reports the Auxiliary Consumption of NTDC Grids separately as Energy injected into the transmission network of NTDC. While calculating the losses as per the formula given in the Commercial Code, the Energy loss of NTDC includes the losses as well as this Auxiliary Consumption. However, as per its tariff determination, the allowed losses for NTDC do not include this Auxiliary Consumption of NTDC Grids. This issue was highlighted by the Market Operator at a meeting held with the professionals of NEPRA and it was concluded that the Auxiliary Consumption of NTDC Grids shall be arranged from the	Test Run Implementation

		local Suppliers of Last Resort at the rate as approved by NEPRA and shall be reported as part of the Energy withdrawals by such Suppliers of Last Resort. It is requested here that NTDC shall be directed to arrange this supply from the respective DISCOs before the CMOD, otherwise, the Balancing Mechanism for Capacity can't work and it will hamper the start of the Market.	
20.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Sub-Section 6.5.2. Allocation of Amount of Compensation for Provision of Ancillary Services and Must Run Generation Among Market Participants In various places in Clause 6.5.2.2 of the above referred Sub-Section of the approved Commercial Code, additional formulas have been incorporated for allocation of amount of compensation for provision of Ancillary Services and Must Run Generation to different Congested Zones to further clarify this calculation.	During the trial run, it was observed that there is a need for elaboration of clauses regarding allocation of charges for Must Run Generation (Transmission Must Run and Reliability Must Run) and Ancillary Service to different Congested Zones. The Congested Zone is a defined area within the transmission network which can import and export Energy from/to other areas. As a result, Energy is exchanged between different Congested Zones and hence the allocation of charges for Must Run Generation and Ancillary Services to different Congested Zones needs to be catered for in the Commercial Code and take into account these Energy exchanges as well. The approved Commercial Code did not have detailed provisions on how to allocate these charges to different Congested Zones in cases where Energy has been exchanged between the boundaries of different Congested Zones. During the implementation of the MMS, formulas were devised and tested to cater for this requirement and the same have also been included in the revised Commercial Code which is being submitted along with this report.	Test Run Implementation

21.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Section 6.2. Must Run Generation The provisions stipulated in Section 6.2 of the approved Commercial Code are amended in such a manner that the System Operator is made responsible to identify the Severely Congested areas and place them in different Congested Zones. The System Operator is also responsible to get this scheme approved from the Authority. Till the time the Authority approves this scheme, there shall be no compensations for Must Run Generation. Also, the transitory establishment of the Congested Zones has been eliminated.	In the consultative sessions held during the trial run, it was highlighted that the System Operator is responsible for safe and reliable operation of the Grid System and it has visibility of the whole network, therefore, it is prudent to put this responsibility on the System Operator to identify the severely Congested Areas and get it approved from the Authority. This important aspect shall be deliberated in detail as currently, the Authority is charging this cost to the network operator in some cases which needs clarity whether, the cost of Must Run Generation will be borne by the Market Participants or will be charged to the network company.	
22.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Sub-Section 6.5.3. Publication of Ancillary Services and Must Run Generation Results The above Sub-Section has been amended in order to limit the publication of Ancillary Services and Must Run Generation results and only Market Participants are given access to such information.	In the consultative sessions held during the trial run, it was highlighted that as compensation for Must Run Generation and Ancillary Services will only be paid to or paid by the Market Participants; therefore, it is only pertinent to share this information with relevant Market Participants /Service Providers only. Making it public does not serve any purpose. In order to address this issue, the revised Commercial Code submitted along with this report include provisions which limits the publication of the results to relevant Market Participants/Service Providers only.	Consultative Session
23.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** **Chapter 18. Miscellaneous, Complementary and Transitory Provisions**	During the trial run, it was observed that the provisions in the approved Commercial Code lack clarity regarding establishment of the Congested Zones at the start of the Market. In order to address this issue, this amendment is included in the revised Commercial Code submitted along	

	In Clause 6.2.1.4, the following sentence is added at the end: "Till the time the System Operator provides this information to the Market Operator, the provisions of Clause 18.2.6.1 shall apply and Clauses 6.2.1.5 and 6.2.1.6 shall not apply. Further in Clause 18.2.6.1, the words "Section 6.2.1" are replaced with "Clause 6.2.1.4" and further provisions are added to establish the procedure for redefining the boundaries of the Congested Zones when the System Operator conducts studies on the Congestions in the Transmission Network.	with this report, which clearly specifies the procedure for establishment of the Congested Zones at the start of the Market. Further, additional provisions have also been added in Chapter 18 to provide clarity regarding redefining the boundaries of the Congested Zones when System Operator conducts studies in future on Congestion in the transmission network and informs the Market Operator accordingly.	Test Run Implementation
24.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Section 6.4. Compensation for Provision of Ancillary Services i. The provisions of the above referred Section are modified in a manner that instead of Market Operator, the System Operator is made responsible to determine the number of kwhrs for which compensation shall be paid to a Generator for the provision of Ancillary Services. ii. Clause 6.4.1.2 is replaced with the following text: "Within eighteen [18] month from the approval of this Code, the System Operator shall make a CCOP whereby a procedure	i. In the consultative sessions held during the trial run, it was highlighted that as per NEPRA Act, the System Operator is responsible for the procurement of the Ancillary Services for the safe and reliable operation of the transmission network. Therefore, it was considered that instead of Market Operator, it is more prudent that the System Operator establish the basis i.e. Kwhrs for the compensation for Ancillary Services. Therefore this amendment ins included in the revised Commercial Code submitted along with this report. ii. During the drafting of the Commercial Code, it was envisaged that the System Operator will require some time to clearly establish all the parameters to be used to calculate the compensation for Generators for providing Ancillary Services and as an interim measure a procedure was given in Appendix 1 of the Commercial	Test Run Implementation

	shall be devised to identify a Generator which may be eligible to receive the compensation as well as to determine the quantity of Energy for which compensation may be paid as provided in Clause 6.4.1.1 above. Till such time, the procedure included in Appendix I shall be applicable and Clause 6.4.1.3 shall not apply. iii. Clause 6.4.1.3 shall be replaced with the following text: "The System Operator shall communicate to the Market Operator, on daily basis for the previous day, the quantity of Energy for which compensation may be paid to each Generator for each Generation Unit for providing, or allowing other Generation Units to provide, Ancillary Services. "	Code. Keeping this in view, the Market Operator submitted the Code, however, in the trial run, it was observed that in the approved Market Commercial Code, this scheme has been changed which created some inconsistencies in the Clauses as well as a deviation from the envisaged scheme. In order to address this issue, the amendments in Clause 6.4.1.2 have been included in the revised Commercial Code submitted along with this report. iii. During the trial run, it was observed that Clause 6.4.1.3 requires amendment to add clarity. Therefore, this clause has been rephrased in the revised Commercial Code submitted along with this report.	
25.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Section 6.2. Must Run Generation i. The above referred Section is divided further into two Sub-Sections i.e. 6.2.1. Congested Areas (Transmission Must Run) and 6.2.2. Reliability and Security of the System (Reliability Must Run). ii. The term "Must Run Generation" has been omitted from the Commercial Code.	i. During the trial run, it was observed that a Generation Plant can become "Must Run" because of two reasons i.e. Congestion or Reliability and Security. Therefore, it was deemed appropriate that further categorization of Generation Plants will add clarity to the provisions of the Commercial Code and therefore this amendment is proposed in the revised Commercial Code submitted along with this report. ii. Generally, the term "Must Run" is used in a different context in the power sector where is meant that these plants must be dispatched	Test Run Implementation

		irrespective of their variable cost. Therefore, to avoid this confusion, the term Must Run Generation has been omitted from the revised Commercial Code submitted along with this report.	
26.	**Chapter 6. Additional Market Charges (Ancillary Service Charges (ASC), Must Run Generation and Operators Fee)** Throughout Chapter 6, the term "Lost Opportunity Cost" has been replaced with the term "Reduced Generation Compensation".	In the consultative sessions held during the trial run, it was highlighted that the term "Lost Opportunity Cost" may create a negative impression among stakeholders who are not well familiar with the terminologies of the competitive markets. Therefore, the more appropriate and neutral word is the Reduced Generation Compensation. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
27.	**Chapter 7. Monthly Settlement (Market Participants and Service Providers)** Sub-Section 7.3.4. Extraordinary Settlements Clause 7.3.4.1 of the above referred Sub-Section of the approved Commercial Code, shall be replaced as: "The Market Operator shall issue an Extraordinary Settlement Statement for a month, where: a) The dispute is settled between Market Participants according to the dispute resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement; b) The dispute is settled between a Market Participant and a Service Provider according to the dispute	During the trial run, it was observed that the reasons for issuance of the Extraordinary Settlement Statement require clarity regarding settlement of disputes among the Market Participants and Service Providers. Therefore, in order to address this issue, this amendment is included in the revised Commercial Code submitted along with this report.	Test Run Implementation

	resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement."		
28.	**Chapter 8. Firm Capacity Certification** Sub-Section 8.3.2. Issuance Of Firm Capacity Certificates The language of the above referred Sub-Section 8.3.2 has been improved and elaborated. This Sub-Section deals with the issuance of the Firm Capacity Certificates to a Generator selling Capacity through Legacy Contracts and the revised text of this Sub-Section stipulates that such Firm Capacity Certificates shall be deemed issued by the Market Operator to the EX-WAPDA DISCOs or KE (for its own Legacy Generators (owned or contracted)) only and this information shall only be provided to the Ex-WAPDA DISCOs and KE for compliance with their Capacity Obligations.	In the trial run, while holding consultative sessions with the stakeholders, it was highlighted that the Legacy Generators are represented in the market by EX-WAPDA DISCOs and KE, and they will be getting their payments as per their respective ppas/epas and are dealt with as per the Special Purpose Agent Code. In this backdrop, it was suggested that there is no need to issue Firm Capacity Certificates to the Legacy Generators and instead it will be deemed that for the Legacy Generators, the Firm Capacity Certificates are issued by MO to the Ex-WAPDA DISCOs and KE as they will be the Market Participants representing those Generators. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
29.	**Chapter 8. Firm Capacity Certification** Sub Section 8.3.3. Registration of the Issued Certificates In Clause 8.3.3.1 of the above referred Sub-Section of the approved Commercial Code, the "**Type of the Certificate**" is added in the list of information to be recorded by the Market Operator as part of the Firm Capacity Register.	During the trial run, it was observed that the Firm Capacity Register to be maintained by the Market Operator, besides other information, should also contain information regarding the type of the Certificate which a Market Participant will be holding as this is an important information. There are two types of certificates to be issued by the Market Operator as explained below: i. Temporary Firm Capacity Certificates to be issued before the COD of the generation plant. ii. Permanent Firm Capacity Certificate to be issued at the COD of the plant.	Test Run Implementation

		Keeping in view the above, this amendment is included in the revised Commercial Code submitted along with this report.	
30.	**Chapter 8. Firm Capacity Certification** Section 8.4. Determination of Initial Firm Capacity The different provisions of the above referred Section of the approved Commercial Code have been amended to clarify the procedure regarding issuance of the Firm Capacity Certificates for thermal based Generation Plants connected below transmission voltage whose dispatch is in the control of the operator of the plant instead of the System Operator. The new provisions stipulate that such Generation Plants shall be treated as non-dispatchable generation technologies are treated at the time of calculation of Firm Capacity.	In the consultative sessions held during the trial run, it was highlighted that the small thermal Generation Plants, connected below transmission voltage, are controlled by its operators and do not receive any dispatch instructions from the System Operator. Hence, their Firm Capacity should be determined in the same manner as Firm Capacity of other non-dispatchable resources (such as wind and solar) is determined. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
31.	**Chapter 8. Firm Capacity Certification** Section 8.4. Determination of Initial Firm Capacity The principle for determination of the Firm Capacity of thermal based Generation Plants as given in the approved commercial code has been revised in a manner that the Firm Capacity shall be calculated based on Installed Net Capacity (Dependable Capacity) and Force Outage Rate of the respective Generation Plant instead of taking average of the historical availability of the Generation Plant as provided in the approved Commercial Code.	During the trial run it was observed that under the existing methodology for determination of the initial Firm Capacity as provided in the approved Commercial Code, consideration of the actual availability for the last three years involves many operational issues due to structure of the Legacy Contracts. Therefore, in order to address these practical issues, it was deemed appropriate to adopt a simplified method at the start of the market which is also aligned with the IGCEP. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Stakeholders Consultation
32.	**Chapter 8. Firm Capacity Certification** Section 8.4. Determination of Initial Firm Capacity The different provisions of the above referred Section of the approved Commercial Code have been amended	During the trial run, it was observed that the historical data regarding availability and actual generation for majority of the Generation Plants is not available and therefore, the Firm Capacity Can't be calculated for each	

	in a manner that the Firm Capacity is calculated for a Generation Plant instead of each Generation Unit of a Generation Plant as provided in the approved Commercial Code.	Generation Unit of a Generation Plant. Secondly, as the mechanism for determination of the Firm Capacity Certificates of thermal based Generation Plants has been revised and the new mechanism is based on Installed Net Capacity (dependable capacity) which is also determined on Generation Plant basis instead of each Generation Unit. Therefore, the provisions of Section 8.4 have been modified to calculate the Firm Capacity for a Generation Plant instead of each Generation Unit of a Generation Plant. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Stakeholders Consultation
33.	**Chapter 9. Balancing Mechanism for Capacity** Sub-Section 9.2.4. STEP 4: Capacity Requirements of Market Participants In Clause 9.2.4.2 of the approved Commercial Code, the term "Act_E" has been replaced with the term "esi" to correct a typo.	As per the proposed scheme of the approved Commercial Code, the Capacity Requirement of Market Participants shall be inclusive of all the losses including the Transmission Losses, however the term "Act_E" doesn't include the transmission losses, while the term "esi" includes the transmission loss. Therefore, the correct term to be used in this Clause is "esi" instead of "Act_E". Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Test Run Implementation
34.	**Chapter 9. Balancing Mechanism for Capacity** Sub-Section 9.2.3. Step 3: Capacity Credited to Market Participants The provisions of the above referred Sub-Section are further clarified to take into account the secondary trading of the Capacity as well for crediting Capacity to the Market Participants.	During the trial run, it was observed that the current provisions of this Sub-Section give the impression that while crediting Capacity provided by Generation Plants to the Market Participants, only the Contracts between the Generators and other parties are considered. However, in actual scenario, Capacity can be traded among multiple Market Participants. For example, if a Generator has sold capacity to a Trader and the Trader has sold it to a Competitive Supplier, the second transaction shall also be	Test Run Implementation

		considered for Crediting Capacity to the Competitive Supplier. Therefore, in order to address this issue, this amendment is included in the revised Commercial Code submitted along with this report.	
35.	**Chapter 9. Balancing Mechanism for Capacity** Sub-Section 9.2.4. STEP 4: Capacity Requirements of Market Participants Clauses 9.2.4.2. A & b of the above referred Sub-Section of the approved Commercial Code have been amended regarding the allocation of Capacity Requirement between the BPCs and Competitive Suppliers in a manner that BPCs which are Market Participants shall be responsible for their own Capacity Requirement instead of assigning this responsibility to the Competitive Supplier.	During the trial run, it was observed that the current allocation method of the Capacity Requirements as given in the approved Commercial Code assigns the responsibility of all BPCs having contracts with a Competitive Supplier, for fulfilling their Capacity Requirements, to the Competitive Supplier including those BPCs who are Market Participants. During the trial run, it was observed that the calculation of the Capacity Requirements will be simpler and more explicit if the BPCs, which are Market Participants, are assigned their own Capacity Requirement and the compliance part is dealt with in accordance with their Contracts with Competitive Suppliers. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Test Run Implementation
36.	**Chapter 9. Balancing Mechanism for Capacity** **Chapter 10. Compliance With Ex-Ante Capacity Obligations** At various places in Chapter 9 and Chapter 10, the Calendar Year has been replaced with Fiscal Year for verification of Compliance with Ex-Ante Capacity Obligations and execution of BMC.	In the consultative session held during the trial run, it was highlighted that all other activities and plans such as Demand Forecast, IGCEP, TSEP, STG Plan, Power Acquisition Programme and investment plan etc. Are prepared on fiscal year basis, therefore, the Capacity Obligations and BMC shall also be determined on Fiscal year basis. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
37.	**Chapter 9. Balancing Mechanism for Capacity**	It was a typographical error in the approved Commercial Code. The intention was to write the word "non-	Test Run Implementation

	In Clause 9.2.3.2 a, the word "Guaranteed Capacity" is replaced with "Non-Guaranteed Capacity".	Guaranteed". Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	
38.	**Chapter 9. Balancing Mechanism for Capacity** In Clause 9.2.4.3, the words "of the Total Demand" are deleted.	This Clause defines the Reserve Margin as a percentage of the Total Demand; however, the reserve margin is always used as a percentage and there is no need to define it this way. It shall only be defined as a percentage. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
39.	**Chapter 10. Compliance With Ex-Ante Capacity Obligations** Sub-Section 10.6.1. Determination of the Capacity Obligations of an Applicant at the Time of Enrolment as a Market Participant or Addition of a BPC by a Competitive Supplier The above referred Sub-Section has been inserted into the approved Commercial Code in order to clarify the procedure regarding evaluation of the compliance with Capacity Obligations at the time of registration of a Market Participant or the addition of a new BPC by a Competitive Supplier.	In the consultative sessions held during the trial run, it was highlighted that the procedure for evaluating the capacity obligations of an applicant (demand side) intending to become a Market Participant or the addition of a BPC by a Competitive Supplier needs to be added in Chapter 10 of the Commercial Code as this mechanism is currently not available in the approved Commercial Code and needs to be added. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
40.	**Chapter 10. Compliance With Ex-Ante Capacity Obligations** Section 10.4. Capacity Obligations The formulas given in the above referred Section of the approved Commercial Code for calculation of Capacity Obligations has been modified to include a factor for Distribution Losses as well which shall be considered for any demand connected at the Distribution Voltage.	In the consultative sessions held during the trial run, it was highlighted that the formulas given in the approved Commercial Code only takes into account the Transmission Loss and it shall also incorporate the Distribution Loss for those demands which are connected in the Distribution Network. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
41.	**Chapter 10. Compliance With Ex-Ante Capacity Obligations**	The April 31st was a typo in the first place; however, this date has been revised in light of the new power	

	Section 10.5. Ex-Ante Verification of Capacity Obligations (Current and Subsequent Years) In Clause 10.5.1.1 of the approved Commercial Code, the words "April 31st "shall be replaced with "July 31st "	procurement regulations of NEPRA because the draft of the power procurement regulations was not available at the time of drafting of the Commercial Code. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Test Run Implementation
42.	**Chapter 11. Yearly Settlement Statements (For BMC and Excess Losses)** Section 11.2. Charges and Compensations for Excess Losses of a TSP The above Section of the approved Commercial Code regarding treatment of excess losses of any Transmission Service Provider has been deleted from the Commercial Code.	In consultative sessions held during the trial run, it was it was highlighted that the Market Operator shall not be involved in the excess loss of any transmission service provider as it is a regulatory issue and in nature of a bilateral transaction between the Market Participants and the transmission service providers. Therefore, the Market Operator shall not be involved in any such transactions. Earlier this mechanism was included because of the conditions of the NTDC tariff determination, which was serving the regulated consumers only, however, as in the Market, there will be parties other than the regulated consumers as well, so this mechanism shall not be there in the Commercial Code. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
43.	**Chapter 11. Yearly Settlement Statements (For BMC and Excess Losses)** Sub-Section 11.4.1. Preliminary Yearly Settlement Statements Clause 11.4.1.1 of the above referred Sub-Section of the approved Commercial Code has been modified to align the issuance date of the Preliminary Yearly Settlement Statement with the procedure given for execution of the Balancing Mechanism for Capacity as given in Chapter 9 of the approved Commercial Code.	During the trial run, it was observed that the issuance of the Preliminary Yearly Settlement Statement should be linked with the final execution of the BMC as per Sub-Section 9.6.2 of the Commercial Code. The text included in the revised Commercial Code, submitted along with this report is as follows: "Within five [5] Business Days of execution of the BMC as per sub-section 9.6.2, the Market Operator shall send, through electronic means, to each Market Participant and to the Service Providers, a Preliminary Yearly Settlement Statement."	Test Run Implementation

44.	**Chapter 12. Payment System** In Clause 12.3.3.3 of the approved Commercial Code, the word "without" is added before the word "prejudice".	During the trial run, it was observed that there is a typo in clause 12.3.3.3 and the correct word is "without prejudice" instead of only "prejudice". Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Test Run Implementation
45.	**Chapter 12. Payment System** **Chapter 13. Guarantee, Security Cover and Advance Instalments** i. A new simplified payment procedure has been incorporated in Chapter 12 and Chapter 13 of the approved Commercial Code. ii. The term "Settlement Guarantee Fund" has been replaced with the term "Settlement Guarantee Cover". iii. The term "Credit Cover" is replaced with the term "Security Cover" in in the approved Commercial Code. iv. A new Clause 13.1.3.7 has been inserted in Chapter 13 of the approved Commercial Code to ensure daily and weekly monitoring of the Security Covers.	i. In the consultative sessions held during the trial run, it was highlighted that the current payment mechanism is transparent, but a bit complex and the same level of transparency can be achieved through a much-simplified procedure. For example, the number of accounts can be reduced from six to two with the same accounting and reporting requirements for transparency. Keeping in view this, the number of accounts has been reduced to two from six and resultantly, the payment process has been revised accordingly. ii. The term "Fund" has some legal connotation which is not aligned with the way the Settlement Guarantee will be organized and utilized as provided in the Commercial Code. Therefore, the correct term to be used is "Cover" instead of "Fund". iii. The term "Credit Cover" is replaced with the term "Security Cover" in in the approved Commercial Code to align the terminology in the whole document. iv. In consultative sessions held during the trial run, it was highlighted that the Market Operator shall continuously monitor the Imbalances of Market Participants to ensure sufficiency of the submitted	Consultative Session

		Security Covers and shall ask the relevant Market Participants to deposit additional Security Cover if their Imbalance exposure is going beyond the amount that has been submitted as Security Cover. In order to address this issue, Clause 13.1.3.7 has been inserted in the revised Commercial Code. Keeping in view above, the requisite amendments in Chapter 12 and Chapter 13 as a whole have been incorporated into the revised Commercial Code submitted along with this report.	
46.	**Chapter 12. Payment System** The term "Notification" has been replaced with the term "Advice" in terms "Debit Notification" and "Credit Notifications" as included in the approved Commercial Code.	This amendment is proposed to avoid misinterpretation of the term "Notification" as per the tax laws of Pakistan because the FBR uses this term in a different meaning than what is intended in the approved Commercial Code. Therefore, this amendment is included in the revised Commercial Code submitted along with this report.	Consultative Session
47.	**Chapter 13. Guarantee, Security Cover and Advance Instalments** A new Clause 13.1.1.3 has been inserted to take into account the impact of relevant taxes while calculating the amount of the Security Cover.	During the trial run, it was observed that the current provisions of Chapter 13 of the approved Commercial Code regarding determination of the Security Cover do not take into account the impact of taxes including GST on the Security Cover. In order to address this issue, a new Cal 13.1.1.3 has been inserted in the revised Commercial Code submitted along with this report.	Test Run Implementation
48.	**Chapter 13. Guarantee, Security Cover and Advance Instalments** New provisions have been added in Chapter 13 regarding release of Security Cover and Settlement Guarantee Cover which will be independent of monthly or annual financial settlements.	During the trial run, it was observed that in case the Contract of a Market Participant is terminated, its participation in the Balancing Mechanism of Energy will be stopped as per the procedure stipulated in the Commercial Code. However, Security Cover/Settlement Guarantee Cover should not be released during the middle	

		of a month as monthly settlement is run for the whole market on the basis of Final Settlement Statement. In case any amount is to be paid by such Market Participant, it will be deducted from its Security Cover/Settlement Guarantee Cover, and the remaining amount (if any) shall be released as part of the monthly settlement cycle. In order to address this issue, the requisite amendments have been incorporated in the revised Commercial Code submitted along with this report.	Consultative Session
49.	**Chapter 13. Guarantee, Security Cover and Advance Instalments** Clause 13.1.3.3 Clause 13.1.3.3 has been amended to provide that the return earned on Security Cover/Settlement Guarantee Cover shall be distributed among the Market Participants.	Any profit generated on Security Cover / Settlement Guarantee Cover balance, net off associated cost, shall be distributed back to the Market participants according to the proportion of their contribution to the balances. In order to address this matter, this amendment has been included in the revised Commercial Code submitted along with this report.	Consultative Session
50.	**Chapter 13. Guarantee, Security Cover and Advance Instalments** Table 2 of the approved Commercial Code has been deleted.	In the consultative session held during the trial run, it was highlighted that Table 2 provides mechanism for determination of initial security cover for the DISCOs prior to the CMOD. However, as the CPPA-G has been granted the Market Operator license and CPPA-G as Special Purpose Agent (SPA) has already mechanisms in place to get payments from the DISCOs, therefore, separate security covers are not needed till the time the Market Operator function is performed by the CPPA-G when it has both the functions of Market Operator as well as SPA. In future, as history of all the DISCOs will be available with the Market Operator which will enable it to determine the quantum of the Security Covers to be provided by each DISCO and therefore, there is no use of this table at this moment and in future as well. Therefore, this table has	Consultative Session

		been deleted in the revised Commercial Code submitted along with this report.	
51.	**Chapter 16. Enforcement of Commercial Code** Different provisions of Chapter 16 of the approved Commercial Code have been modified in a manner that if disconnection request is issued for any Market Participant (Generators) by the Market Operator, then the same shall be informed to the System Operator as well to issue de-synch instruction to the relevant facilities and the System Operator shall be bound by the instructions of the Market Operator.	During the review of the Grid Code in the trial run, it was highlighted that if the Market Operator issues a request for Disconnection of a Market Participant, then in order to disconnect that Market Participant, the System Operator also needs to be informed to issue de-synch instruction to give effect to the disconnection request. In order to address this issue, the relevant provisions of Chapter 16 have been amended and incorporated into the revised Commercial Code submitted along with this report.	Trial Run Implementation
52.	**Chapter 16. Enforcement of Commercial Code** At various places in Chapter 16, new provisions have been added in the approved Commercial Code with respect to the scenario where a network licensee does not disconnect a defaulting consumer as requested by the Market Operator, then is such case, the cost of any Energy withdrawn after the data and time as specified in the request of the Market Operator shall be borne by respective network licensee.	During the trial run, it was observed that there may be a scenario in which the network licensee does not comply with the request of the Market Operator regarding disconnection of a Market Participant who has defaulted on its obligations under the Commercial Code. In such case, if any Energy is withdrawn by such defaulting Market Participant from the network, the respective network licensee shall bear the cost and not the Market Operator. In order to address this issue, the relevant provisions of Chapter 16 are amended and incorporated in the revised Commercial Code submitted along with this report.	Consultative Session
53.	**Chapter 18. Miscellaneous, Complementary and Transitory Provisions** Sub-Section 18.2.12. Registration of Legacy Contracts A new Sub-Section 18.2.12 has been inserted in Chapter 18 of the approved Commercial Code to provide a procedure for registration of the Legacy Contracts as it is a very important aspect of the CTBCM and needs to be reflected in the Commercial Code.	In the consultative sessions held during the trial run, it was highlighted that the procedure for registration of the Legacy Contracts should be provided in the Commercial Code. Currently, this mechanism was provided in the Contract registration CCOP and Market Participation Agreement (MPA). It was considered more appropriate to incorporate this in the Commercial Code. This mechanism provides a procedure to determine a Cap up to which the Ex-WAPDA DISCOs will not be subject to	Consultative Session

		any Imbalances and any energy withdrawal above this cap will be settled at Marginal Price. In order to address this, new Sub-Section 18.2.12 has been incorporated in the revised Commercial Code submitted along with this report.	
54.	**Chapter 18. Miscellaneous, Complementary and Transitory Provisions** The language in Table 8 of the approved Commercial Code (now replaced with Clause 18.2.5.1 d) has been modified to clarify the language regarding allocation to KE from the Legacy Contracts of EX-WAPDA DISCOs.	In the consultative sessions held during the trial run, it was highlighted that the language regarding allocation to KE from the Legacy Contracts of EX-WAPDA DISCOs is ambiguous and needs further clarity. The current language stipulates that the allocation for KE will be as per its bilateral contract with CPPA-SPA. However, the contract is not yet signed and also this contract will be signed as Power Purchase Agency Agreement (PPAA). The amended text that is reflected in the revised Commercial Code submitted along with this report is as under: "The KE shall be assigned its share as per its PPAA or any other arrangement with CPPA-SPA". This matter is still under discussion, the final scheme of Allocation to KE will be communicated to NEPRA soon.	Consultative Session
55.	**Chapter 18. Miscellaneous, Complementary and Transitory Provisions** Sub-Section 18.2.6. Revision of the Allocation Factors A new Sub-Section 18.2.6 has been inserted in the approved Commercial Code for revision of the allocation factors for the Ex-WAPDA DISCOs until a detailed mechanism is approved under the NE Plan.	In the consultative sessions held during the trial run, it was highlighted that the mechanism for revision of allocation factors is needed until the NE Plan clearly establishes a mechanism for this purpose. This mechanism is needed because during the trial run, it was observed that some DISCOs were non-compliant with their Capacity Obligations, whereas, other DISCOs had sufficient surplus capacity to fill this gap. It was recommended by the DISCOs to include a procedure in the commercial code for re-allocation of the surplus to those DISCOs who are in deficit.	Consultative Session

		In order to address this issue, this new Sub-Section 18.2.6 has been incorporated in the revised Commercial Code submitted along with this report.	
56.	**Chapter 18. Miscellaneous, Complementary and Transitory Provisions** The Capacity Obligations percentage for the 3rd and 4th years as given in Table 3 to Table 6 of the approved Commercial code are replace with the words "1-CAGR".	In the consultative sessions held during the trial run, it was highlighted that the uncertainty margin as given in these tables shall not be hardcoded values but linked with the Compound Average Growth Rate (CAGR) to cover for the uncertainty in the demand forecasts.	Stakeholders Consultation
57.	**Chapter 19. Appendices** In Clause 19.1.2.2 and 19.1.3.1.(a), the following labels are required to be added to cover the additional parameters of the power system operations: i. "Fuel Constraint" ii. "Voltage Support" iii. "Test Run" The existing label "Zero Variable Cost" shall also be replaced with "Zero Fuel Cost" to avoid confusion between zero fuel cost and zero variable cost.	During consultations with different stakeholders, it was highlighted that due to shortage of fuel, Generation Plants are forced to run on partial load in order to conserve fuel. This situation arose only due to acute shortage of fuel in the country in recent months and was not envisaged earlier. Therefore, the label "Fuel Constraint" is required at the time of determination of Marginal Prices in order to exclude such Generation Plants from setting the Marginal Prices and getting compensation for Ancillary Services and Must Run Generation. Furthermore, it was also observed that some Generation Plants are run for testing purposes, which requires separate treatment. Therefore, the label "Test Run" needs to be added. Such Generation Plants shall also be excluded from setting the Marginal Prices and getting compensation for Ancillary Services and Must Run Generation. Further, it was also considered appropriate that the power plants running for voltage support need to be identified separately. Therefore, the label "Voltage Support" needs to be added.	Consultative Session

		Due to addition of the above referred labels and renaming of the existing labels, in Clause 19.1.2.2, certain additional amendments are required in in Chapter 19 as well as in Chapter 6 which have been included in the revised Commercial Code submitted along with this report.	
58.	**Chapter 19. Appendices** Figure 2, Figure 3 and Figure 4 in Chapter 19 are amended to make these aligned with the new labels inserted in the revised Commercial Code and assigned to the Generation Units.	During the trial run, it was observed that these figures sare based on old labels and needs to be updated in accordance with the new labels for Generation Units as incorporated in the revised Commercial Code submitted along with this report.	Consultative Session
59.	**Chapter 19. Appendices** The Clause 19.1.2.2 has been amended in order to exclude the nuclear technology from reporting under the label of "Zero Fuel Cost".	During the trial run, it was observed that the nuclear technology is not a Zero Fuel Cost technology, and its characteristics are also different from other Zero Fuel Cost technologies. Therefore, this technology should be reported as any other thermal generation units with its variable cost mentioned. In order to address this issue, Clause 19.1.2.2 has been amended and incorporated in the revised Commercial Code submitted along with this report.	Test Run Implementation
60.	**Chapter 19. Appendices** i. There was a typo in clause 19.1.2.2. (b8) and the words "ninety percent" are replaced with "ninety five percent" to correct this typo.	i. In order to correct the typos, an amendment has been made in clause 19.1.2.2 (b8) in the revised Commercial code. Further, it is clarified that in case of Combined Cycle Gas Turbines (CCGTS) whose availability varies with ambient site conditions, the System Operator, at its discretion, may either revise the availability of the generator accordingly or use a different factor and clearly convey it to the Market Operator and the relevant Market Participant. Moreover, if the available capacity goes down than 95% not due to action of System Operator for	Test Run Implementation

	ii. The percentage values mentioned in Clauses 19.1.2.2 Sub-Clause(s) (b8) and (b9) are aligned so that there is no difference between both values coherent	frequency regulation but the driver is different i.e., Temperature affecting its availability and therefore should not be compensated for reduced generation. ii. The clause 19.1.1.2 (b8) specified a percentage of 95% for fully loaded generators while clause 19.1.1.2 (b9) specified a percentage of 90% for partially loaded. This should be corrected in a manner that any Generator loaded over 95% will be considered fully loaded and below 95% will be considered partially loaded. In order to make this correction the Clause 19.1.1.2 (b9) has been amended and incorporated in the revised Commercial Code submitted along with this report.	
61.	**Chapter 19. Appendices** Clauses 19.1.3.1 (a) and (b) of the approved Commercial Code have been amended to include provisions for the System Operator to specify the type of Ancillary Services obtained from the Generation Units while providing information to the Market Operation for determination of compensation for Ancillary Services.	In the consultative sessions held during the trial run, it was highlighted that this is important information for audit purposes and the System Operator shall communicate this information to the Market Operator. In order to address this issue, Clauses 19.1.3.1 (a) and (b) have been amended and incorporated in the revised Commercial Code submitted along with this report.	Consultative Session
62.	**Applicable to all Chapters** Amendment in the text is made in the text of the approved Commercial Code to clarify the clauses of Commercial Code in order to objectively implement and execute the relevant action thereunder.	During the trial run, it was observed that certain provisions of the Commercial Code stipulate alternate procedures in case of special circumstances. However, the flow of such provisions did not include exclusionary provisions from the normal procedure, hence there was some confusion. In order to bring clarity and certainty, these procedures have been refined to incorporate the necessary	Test Run Implementation

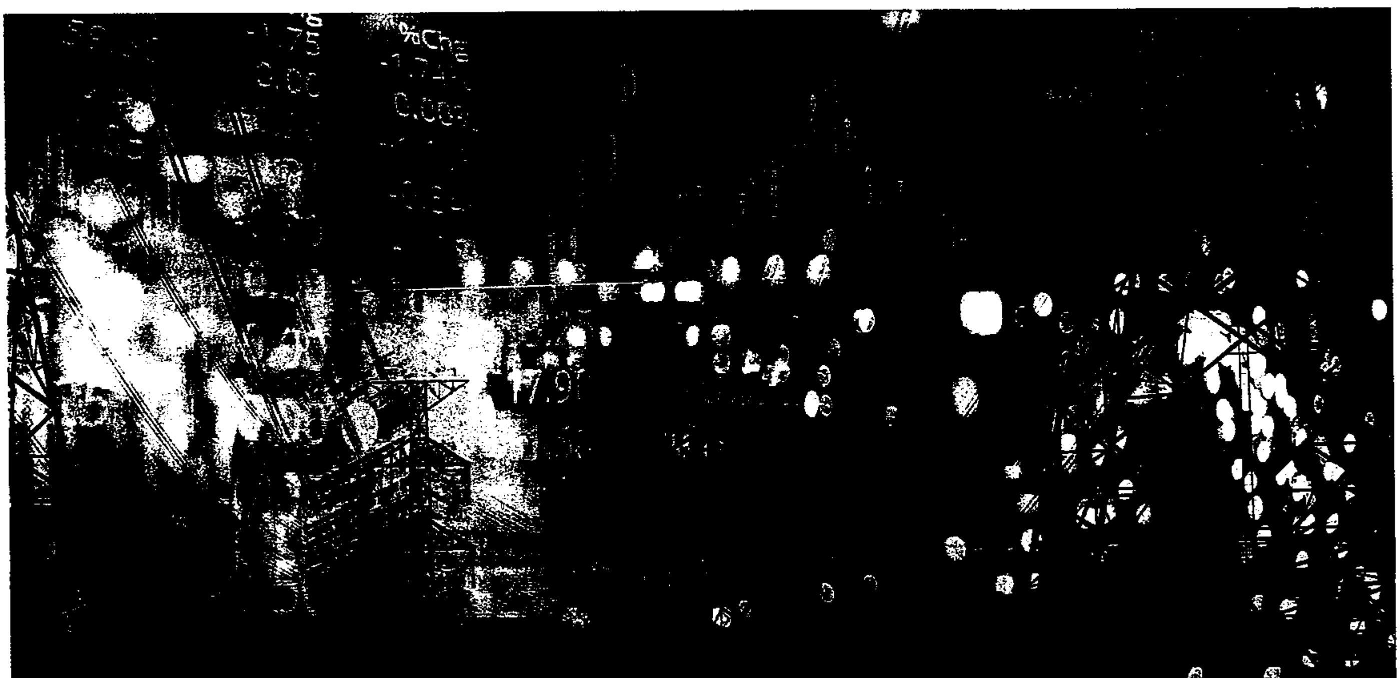
		exclusionary provisions. For example, in Chapter 6, Clause 6.2.1.4. It was written that: "The System Operator shall identify all severely Congested Areas and place them into different Congested Zones considering their location in the Grid System and inform the Market Operator accordingly. Till the time the System Operator provides this information to the Market Operator, the provisions of Clause 18.2.7.1 shall apply." While the Clause below (6.2.1.5) stated that: "The Market Operator shall submit this information to the Authority for approval and consider the area as a Congested Zone for Settlement purposes, from 0:00 a.m. Of the first day of the first month immediately after approval of the Authority." In the above Clauses, there is confusion that when the normal procedure is discontinued and the alternate procedure is adopted, then how to continue reading of the remain procedure. The revised Clause has clarified this issue in the following way that an exclusionary provision has been added at the end of the Clause: "6.2.1.4. The System Operator shall identify all severely Congested Areas and place them into different Congested Zones considering their location in the Grid System and inform the Market Operator accordingly. Till the time the System Operator provides this information to the Market Operator, the provisions of Clause 18.2.7.1 shall apply ***and Clauses 6.2.1.5 and 6.2.1.6 shall not apply***."	

II

CPPA

Pakistan Electricity Market Operator

Market Commercial Code



Electric Power Market Operator of Pakistan

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Introduction

Pursuant to Section 23B of the Act, the Market Operator is required to prepare a Commercial Code to regulate its operations, standards of practice and business conduct of market participants and their representatives. The Commercial Code was submitted by the Market Operator to the Authority for approval and the same has been approved by the Authority after following due regulatory process.

The Commercial Code establishes efficient, non-discriminatory, and transparent market mechanisms which are centrally administered by the Market Operator including the settlement and payment arrangements and procedures. This Code is an essential requirement for the administration of the market as it specifies the rights and obligations of the Market Participants and Service Providers related to the market. This Code also sets out the procedures among different market players to exchange information. All Market Participants and Service Providers shall sign respective agreements (Market Participation Agreement or Service Provider Agreement, as the case may be) with the Market Operator as per provisions of this Code and shall abide by the Commercial Code at all times to the extent this Code is applicable to them.

For a reader to understand this Code, it is important to highlight the roles of different institutions that will play their part in the CTBCM. These roles are just summarized here for the understanding of the reader; however, each entity will perform its roles as per the provisions of the relevant rules, regulations, licenses, authorization, registration and codes.

The role of different entities is classified in three major categories i.e. Operators, Market Participants and Service Providers. Further details of these roles are given below.

Operators

Operators are entities which are responsible for the operation of the electric power system and the market. These entities provide non-discriminatory services to all market players to enable the operation of the electric power system and trading of electric power. As per provisions of the Act, there are two operators in the electricity market of Pakistan i.e., the Market Operator and the System Operator. The roles and responsibilities of the Market Operator and the System Operator are described below.

1. Market Operator

The Market Operator is an entity responsible for establishing and administering the wholesale electric power market and shall perform, *inter alia*, the following functions:

a) enrolment of Market Participants and Service Providers;

b) review of compliance of Contracts with the Commercial Code and registration of Contracts;

c) registration of the Trading Points where commercial transactions may take place among Market Participants;

d) registration of Metering Points, other than Trading Points, which are necessary for proper implementation of this Code;

e) administration of the Balancing Mechanism for Energy and calculating other market charges i.e charges for Transmission Must Run, Reliability Must Run, Ancillary Services, and Market Operator Fee;

f) calculation of Firm Capacity of Generation Plants and issuance of Firm Capacity Certificates;

g) administration of the Balancing Mechanism for Capacity;

h) Calculation of the Capacity Obligations of Market Participants and verification of compliance with such obligations;

i) administering a settlement and payment system for the Capacity and Energy Balancing Mechanisms to clear differences between actual and contracted quantities;

j) administering a payment system for the Imbalances of Market Participants and other market charges, including the verification and registration of Security Covers; and

k) administer dispute resolution procedures in accordance with this Code.

The Market Operator will also be in charge to monitor market development and effectiveness and to propose changes for enhancing its efficiency. The Market Operator shall carry out all of its activities in accordance with the provisions of the Act, rules, regulations, its License, this Code and any other applicable legal instruments.

2. SYSTEM OPERATOR

The System Operator is an entity responsible for planning, dispatch and secure & reliable operation of the Transmission and relevant segment of Distribution Network as specified in the Grid Code. The duties of the System Operator, *inter alia,* include:

a) Generation scheduling, unit commitment and dispatch;

b) Transmission scheduling and generation outage coordination including cross border Transmission coordination;

c) conducting reliable short and medium term operational planning;

d) implementing the Security Constrained Economic Dispatch (SCED) for secure and economic operation of the system including Transmission Congestion management;

e) scheduling and dispatching the necessary Ancillary Services;

f) calculation of System Marginal Prices for each hour;

g) keeping the system in permanent balance by considering the security and reliability constraints;

h) responsible for system planning for long term capacity; and

i) such other activities as may be required for reliable and efficient system operations.

The System Operator will perform its duties in accordance with the provisions of the Act, rules, regulations, License, the Grid Code, this Code and any other applicable legal instruments. To ensure transparency in its operations, the System Operator will publish planning reports, real time operational decisions and the results of the dispatch on its website.

Market Participants

The Market Participants shall be the entities which buy and/or sell Energy and/or Capacity in the wholesale electric power market. These are the players who shall be carrying out transactions in the market. These entities can be broadly categorized as follows:

a) Generation Companies;

b) Captive Generators connecting to the national grid;

c) Electric Power Suppliers;

d) Electric Power Traders;

e) Bulk Power Consumers.

1. Generation Companies

A Generation Company shall be an entity which has installed a Generation Unit or a Generation Plant and is engaged in production and selling of electric power. To participate in the CTBCM, a Generation Company shall abide by the following requirements:

a) A Generation Plant or a Generation Unit of the Generation Company which has been classified as a Dispatchable Generation Unit shall be operated in accordance with the centralized Security Constrained Economic Dispatch (SCED.

b) A Generation Plant or a Generation Unit of the Generation Company which has been classified as a Non-Dispatchable Generation Unit shall be operated in accordance with the conditions, requirements and procedures specified in the Grid Code.

c) Within its technical capabilities, it shall provide the Ancillary Services required by the System Operator, as specified in the Grid Code.

d) It shall enrol as a Market Participant if it sells or plans to sell the Energy and/or Capacity to other Market Participants through a Bilateral Contract and/or Balancing Mechanism of Energy and Capacity. However, it is clarified that a Generation Company whose all Generation Plants or Generation Units, are connected to a Distribution Network at the distribution voltage which does not fall in the scope of the Grid Code, and sells all its Capacity and Energy to an Electric Power Supplier or an Electric Power Trader, shall not be required to become a Market Participant.

e) A Generation Company may sell all of its Energy and/or Capacity through the Balancing Mechanisms as a merchant plant without registering any Bilateral Contract with the Market Operator only if it is capable to provide all types of Ancillary Services as mentioned in this Code except Black Start Capability.

2. Captive Generator

A Captive Generator shall be an entity which has installed a power plant to generate electricity primarily for its own use. To participate in the CTBCM i.e. the Captive Generator injects/withdraws Energy into/from the Grid System, a Captive Generator shall abide by the following requirements:

a) A Generation Plant or a Generation Unit of the Captive Generator shall be operated in accordance with the conditions, requirements and procedures specified in the Grid Code.

b) Within its technical capabilities, it shall provide the Ancillary Services required by the System Operator, as specified in the Grid Code.

c) It shall enrol as a Market Participant if it sells or plans to sell the Energy and/or Capacity to other Market Participants/BPCs through a Bilateral Contract and/or Balancing Mechanism of Energy and Capacity or where it intends to wheel electric power from the Captive Generating Plant to the destination of its own use.

d) However, it is clarified that a Captive Generator whose all Generation Plants or Generation Units are connected to a Distribution Network at the distribution voltage which does not fall in the scope of the Grid Code, and sells all its Capacity and Energy to an Electric Power Supplier or an Electric Power Trader, shall not be required to become a Market Participant.

e) A Captive Generator may sell all of its Energy and/or Capacity through the Balancing Mechanisms as a merchant plant without registering any Bilateral Contract with the Market Operator only if it is capable to provide all types of Ancillary Services as mentioned in this Code except Black Start Capability.

3. Electric Power Suppliers

An Electric Power Supplier (EPS) shall be a Licensed entity as stipulated under the Act, which may involve in the procurement of electric power (Energy and Capacity) and sell it to the end consumers or re-selling it to other Market Participants as specified in the applicable rules and regulations. In the CTBCM, there shall be two types of Electric Power Suppliers Licensed by the Authority namely the Competitive Supplier and the Supplier of Last Resort.

As a Market Participant, the licensed Electric Power Supplier shall register its Contracts (with other Market Participants or BPCs) with the Market Operator as specified in Chapter 3 of this Code, provided that the Supplier of Last Resort shall not be required to register with the Market Operator its Contracts with its consumers.

4. Electric Power Trader

An Electric Power Trader shall be a Licensed entity which may carry out the functions of trading of electric power in accordance with the provisions of the relevant regulations, its Licence and other applicable documents. An Electric Power Trader may perform any or all of the following functions subject to the terms & conditions of its Licence:

a) Import of electric power (Energy and/or Capacity);

b) purchase of the electric power from a Generator or an Electric Power Trader or an Electric Power Supplier;

c) sale of electric power to an Electric Power Trader or an Electric Power Supplier;

d) Export of the electric power.

An Electric Power Trader may enter into an agreement with one or more Generators and sell the aggregated Generation in the CTBCM through Bilateral Contracts and/or Balancing Mechanisms. For Imports, the seller will be exempted from enrolment as Market Participant and for Exports, the buyer, will be exempted from enrolment as a Market Participant. The Market Participant that carries out Imports or Exports will represent the other party in the CTBCM.

5. Bulk Power Consumers

A Bulk Power Consumer (BPC) is a consumer who may buy electric power, Energy and/or Capacity, from the wholesale market or from an Electric Power Supplier of its choice through a Bilateral Contract as per the applicable rules and regulations.

A Bulk Power Consumer may be exempted from enrolling as a Market Participant in case it decides to buy both its Energy and Capacity from the relevant Supplier of Last Resort/DISCO or it decides to sign a Standardized Load Following Supply Contract with a Competitive Supplier, as per the conditions stipulated in this Code.

Service Providers

These are entities which provide non-discriminatory services to Market Participants to enable the transactions in the market. These entities are not involved in trading in the market, rather provide services to enable trading in electric power. The different types of Service Providers and their roles and responsibilities are described below.

1. Transmission Service Providers

A Transmission Service Provider (TSP) shall be responsible for providing non-discriminatory Transmission services to enable wholesale buying and selling of electric power (Energy and/or Capacity). TSPs shall include NTDC, which is the largest TSP and Licensed as national grid company by the Authority, the Transmission Licensed activity of K-Electric, Licensed Provincial Grid Companies (PGCs) and Special Purpose Transmission Licensees (SPTLs). All Transmission Service Providers shall be enrolled with the Market Operator as Service Providers.

Consistent with the Act, its license conditions and applicable rules and regulations, a Transmission Service Provider shall provide Open Access to the Market Participants subject to payment of use of system charges as determined by the Authority. Additionally, the TSP shall sign Connection Agreements with Generation Companies, Captive Generators, Distribution Licensees, network companies from foreign countries or territories where the applicability of the Act is not extended, and BPCs connected directly to transmission network. Such agreement shall also cover providing access to the Meters and metering values to an authorised Metering Service Provider in order to enable it to comply with its obligations.

2. Distribution Network Service Providers

A Distribution Network Service Provider shall be a Licensed entity as defined in the Act which is required to develop and operate the Distribution Network infrastructure to enable the Generators and/ or BPCs connected to such network to participate in the wholesale market. All Distribution Network Service Providers shall be enrolled with the Market Operator as Service Providers.

Consistent with the Act, the condition of its License and applicable rules and regulations, a Distribution Network Service Provider shall provide Open Access to its network to enable buying and selling of electric power among Market Participants subject to payment of use of system charges determined by the Authority and signing use of system agreements as required in the applicable rules and regulations. For information of Market Participants in relation to their market decisions, a Distribution Network Service Provider shall also publish on its website information related to the network availability and its future expansion plans.

3. Metering Service Providers

Metering Service Provider (MSP), in addition to the duties set-forth in the Grid Code and Distribution Code, shall be responsible:

a) to collect all metering information required under this Code and its operational procedures;

b) to assess the completeness and consistency of the metering information; and

c) to transfer the metering information to the Market Operator for settlement purposes and other relevant entities through electronic means, at such intervals as stipulated in the relevant operational procedures.

All Metering Service Providers shall be enrolled with the Market Operator as Service Providers.

4. The Independent Auction Administrator

The Independent Auction Administrator (IAA) shall be an entity registered with the Authority which shall perform the function of facilitating the electric power suppliers, in accordance with the applicable power procurement regulations of NEPRA, through the procurement of new Capacity and/or Energy or existing uncontracted Capacity and/or Energy through Contracts. The IAA will act independently from commercial interest during administration of the auction process.

5. The Special Purpose Agent (CPPA-G)

Prior to CMOD, the CPPA-G was registered by the Authority as the Market Operator under the NEPRA (Market Operator Registration, Standards and Procedure) Rules, 2015 and performed the following two distinct functions:

a. Agent of Distribution Licensees (Ex-WAPDA DISCOs in their role as Suppliers of Last Resort) for procuring electric power on their behalf and administration of the Legacy Contracts-CPPA-G
b. Market development to organize a wholesale electric power market in Pakistan.

The Special Purpose Agent is the name assigned to the role of CPPA-G only related to the agent of Distribution Licensees to the extent of administration of the Legacy Contracts-CPPA-G after CMOD as CPPA-G will no longer be allowed to sign other contracts on behalf of Ex-WAPDA DISCOs and KE in their role as Suppliers of Last Resort. For this role, the CPPA-G shall be registered by the Authority as Special Purpose Agent under section 25A of the Act. For clarity of the reader, the term Special Purpose Trader as used in different documents has been renamed as Special Purpose Agent to avoid the confusion between a licensed Trader and this agency function which will be registered with the Authority.

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Acronyms

ARE	Alternative and Renewable Energy
ASC	Ancillary Services Charges
BMC	Balancing mechanism for Capacity
BME	Balancing mechanism for Energy
BPC	Bulk Power Consumer
CAGR	Compound Average Growth Rate
CCOP	Commercial Code Operational Procedure
CCRP	Commercial Code Review Panel
CCWG	Commercial Code Working Group
CMOD	Competitive Market Operations Date
COD	Commercial operations date
CPPA-G	Central Power Purchasing Agency (Guarantee) Limited
CTBCM	Competitive Trading Bilateral Contract Market (competitive wholesale electricity market of Pakistan)
DISCOs	Distribution Companies
EPA	Energy Purchase Agreement
FSS	Final Settlement Statement
FOR	Forced Outage Rate
FYSS	Final Yearly Settlement Statement
IAA	Independent Auction Administrator
IGCEP	Indicative Generation Capacity Expansion Plan
KE	K-Electric, formerly known as KESC
MO	Market Operator
NEPRA	National Electric Power Regulatory Authority
NTDC	National Transmission and Dispatch Company
PPA	Power Purchase Agreement
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
TSP	Transmission Service Provider
WAPDA	Water and Power Development Authority

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Chapter 1. GENERAL CONDITIONS

1.1. OBJECTIVES AND SCOPE

1.1.1. TITLE

1.1.1.1. This code shall be called the Commercial Code (the "Code").

1.1.2. OBJECTIVES

1.1.2.1. The general objectives of the Commercial Code are:

a) to establish, govern and promote efficient, non-discriminatory and transparent market mechanisms centrally administered by the Market Operator, including the Settlement and payment arrangements and procedures thereof;

b) to govern the terms and conditions to participate in the Market, and the buying and selling of electric power among Market Participants and other Market Transactions after the CMOD;

c) to promote the development of competition;

d) to set out the rights and responsibilities of Market Participants in relation to buying and selling of electric power, settlement and payments of Imbalances and settlement of other market charges;

e) to set out the rights and responsibilities of the Service Providers with respect to provision of metering service and other allied functions related to the Market;

f) to provide the rights and responsibilities of the Market Operator as well as the Market related functions of the System Operator;

g) to provide coordination mechanisms between the Market Operator, the System Operator and other Service Providers in performing their functions related to the Market;

h) to ensure adequate information dissemination for protection of transparency in the Market; and

i) to promote and enable the development of competitive power market in Pakistan in accordance with the Act, the rules and regulations made thereunder and the approved market design.

1.1.3. APPLICABILITY

1.1.3.1. This Commercial Code shall be applicable from the date of its approval by the Authority except for Market Transactions. On the date of CMOD, the whole Code shall be applicable. This Code shall be binding on the Market Operator, System Operator and all Market Participants and Service Providers to the extent it is applicable to them.

1.1.4. SCOPE

1.1.4.1. The Commercial Code establishes the procedures and conditions for the Market Operator for administration of the Market, the framework for Market Participants to buy and sell Energy and/or Capacity and conditions for provision of market services by System Operator and Service Providers.

1.2. INTERPRETATION

1.2.1. DEFINITIONS

1.2.1.1. Capitalised words and expressions used in this Code, unless the context otherwise requires, shall have the following meaning:

1. **"Act"** means the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (Act No. XL of 1997), as amended from time to time;
2. **"Admission Application"** means the document which an Applicant is required to submit when applying for enrolment with the Market Operator, in the form as set out in the applicable CCOP;
3. **"Allocation Factor"** means a value, expressed in percentage, calculated as per provisions of National Electricity Policy, which is used to commercially allocate the Legacy Contracts-CPPA-G to each EX-WAPDA DISCO separately. For KE, the allocation factor shall be a value as per its power purchase agency agreement with the SPA, which may be revised from time to time as per the terms and conditions of the power purchase agency agreement or any other arrangement in place with SPA;
4. **"Amendment"** means any change, modification or deletion of the existing provisions of this Code or the CCOPs or insertion of any new provisions in this Code or CCOPs;
5. **"Amendment Submission"** means the requests for review or amendment of this Code, submitted as per provisions of this Code;
6. **"Amounts Payable"** means the amount of money, expressed in PKR, that a Market Participant is required to pay in order to discharge its obligations as per the Settlement Statements issued by the Market Operator;
7. **"Amounts Receivable"** means the amount of money, expressed in PKR, that a Market Participant is entitled to receive, as per the Settlement Statements issued by the Market Operator;
8. **"Ancillary Services"** has the meaning assigned to the term in the Grid Code;
9. **"Applicable Law"** means the relevant laws of Pakistan including federal, provincial and local laws;
10. **"Applicant"** means any person who has filed an application to enrol with the Market Operator in accordance with the provisions of Chapter 2;
11. **"Adjudication Tribunal"** means a tribunal established by the Authority for resolution of disputes under the Commercial Code;
12. **"Adjudicator"** means a member of the Adjudication Tribunal to adjudicate a Dispute;
13. **"Advance Instalment"** means an amount submitted for financial security against the Amounts Payable as per Final Yearly Settlement Statement or Extraordinary Yearly Settlement Statement, by a Market Participant as per provisions of Chapter 13;

14. **"ARE Generator"** means a Generator which produces electric power through renewable resources;
15. **"Authority"** means the National Electric Power Regulatory Authority established under Section 3 of the Act;
16. **"Available Capacity"** means the share of the Dependable Capacity, which is available for dispatch by the System Operator at any specific period of time;
17. **"Availability Declaration"** has the same meaning assigned to the term in the Grid Code;
18. **"Back-feed Energy"** means the Energy consumed by a Generation Plant or Generation Unit, while the Generation Plant or Generation Unit is not dispatched;
19. **"Back-up Meter"** means a meter installed at the Metering Point for checking or backup purposes as prescribed in the Grid Code;
20. **"Balancing Mechanism for Energy"** means the mechanism, centrally administered by the Market Operator, to settle the Imbalances between the metered quantities, that measure the real time Energy injected into or withdrawn from the Transmission or Distribution Network, and the contracted quantities, registered with the Market Operator, of each Market Participant;
21. **"Balancing Mechanism for Capacity"** means the mechanism, centrally administered by the Market Operator, to settle the Imbalances as defined in Clause 116.a;
22. **"Balancing Period"** means the period for which the Market Operator determines whether a Market Participant had Imbalances, either in Energy or in Capacity, as the case may be;
23. **"Bilateral Contract" or "Contract"** means an agreement, executed in accordance with the provisions of this Code, between two parties for the sale and purchase of a defined amount of Energy and/or Capacity for each Energy Balancing Period or Capacity Balancing Period, as the case may be;
24. **"Bulk-Power Consumer (BPC)"** shall have the meaning assigned to the term in the Act;
25. **"Business Day"** has the meaning assigned to the term in Clause 1.2.4.1;
26. **"Cap"** means the maximum amount of Energy up to which the EX-WAPDA DISCOs or KE shall not be subject to any Imbalances, calculated pursuant to Clause 18.2.10.1.c);
27. **"Capacity" or "Electric Capacity"** means the ability to produce electrical energy (expressed in terms of Watts or its standard multiples) that Generators offer to the Market as a product and it is acquired by Market Participants to comply with their Capacity Obligations in order to guarantee appropriate security of supply in Pakistan;
28. **"Capacity and Associated Energy Supply Contract"** shall have the meaning assigned to the term in Section 3.3.2;
29. **"Capacity Balance"** shall have the meaning assigned to the term in Clause 9.2.5.1;
30. **"Capacity Balancing Period"** shall have the meaning assigned to the term in Clause 9.1.2.1;
31. **"Capacity Obligations"** shall have the meaning assigned to the term in Chapter 10;
32. **"Capacity Requirement"** is the requirement of a Market Participant based on average withdrawal from the Grid during the Critical Hours calculated as per Sub-Section 9.2.4;

33. **"Captive Generating Plant"** shall have the meaning as assigned to this term in the Act;
34. **"Captive Generator"** means a person who owns and operates a Captive Generating Plant;
35. **"Category (in relation to a Market Participant)"** shall have the meaning as assigned to the term in Clause 2.1.1.2;
36. "**Chapter**" means a chapter of this Code;
37. **"Clause"** means a clause of this Code;
38. "**Clearing Day**" means the Business Day on which the Market Operator pays to the Market Participants the amounts payable to them as per the Final Settlement Statements or Final Yearly Settlements Statements or Extraordinary Yearly Settlement Statements;
39. **"Close of Banking Business"** means (5) p.m., Pakistan Standard Time (PST) or any other time specified by the State Bank of Pakistan or the Federal Government;
40. **"Commercial Code Operational Procedure" or "CCOP"** means an operating procedure, developed by the Market Operator or the System Operator or a Service Provider, as the case may be, and approved by CCRP for proper implementation of this Code;
41. **"Commercial Code Working Group"** means a group organised by the Market Operator which consists of representatives of the Market Operator, System Operator, Market Participants and Service Providers to carry out the functions as assigned to it under this Code;
42. **"Commercial Metering System"** means the system, established according to the requirements of the Grid Code and Distribution Code, to measure the Energy injected into or withdrawn from the Transmission or Distribution Network by a Market Participant and used for settlement purposes by the Market Operator;
43. **"Company"** means a company registered under the Laws of Pakistan;
44. **"Competitive Market Operation Date" or "CMOD"** means the date set by the Authority for commencement of commercial operations of the CTBCM after coming into force of sections 23A and 23B of the Act;
45. **"Competitive Supplier"** means a person licensed under section 23E of the Act to supply electric power to only those consumers who are located in the territory specified in its licence and meet the eligibility criteria laid down by the Authority;
46. "**Compliance with Capacity Obligations Report**" shall have the meaning assigned to the term in Sub-Section 10.6.1 of this Code;
47. **"Compound Average Growth Rate" or "CAGR"** is the mean annual growth rate of the Peak Demand of the Market Participants during the forecast horizon considered for the calculation of the Capacity Obligations.
48. **"Condition"** means a condition of this Code;
49. **"Confidential Information"** means:

a) proprietary information of a person or such other information which has been explicitly specified by the disclosing person as confidential, where the disclosure of such information may reasonably be expected to:

   a.1. prejudice significantly the competitive position of the disclosing person;

   a.2. result in material loss or gain to the disclosing person or any other person;

   a.3. compromise the implementation of this Code; or a.4. result in the disclosing person being in breach of a bona fide confidentiality agreement; and

b) information required by the National Electric Power Regulatory Authority Licensing (Market Operator) Regulations, 2022, this Code or other Applicable Laws to be kept confidential, provided that information contained in the Admission Application to become a Market Participant and information required to be published under this Code shall not be treated as Confidential Information;

50. **"Congested Area"** shall have the meaning assigned to the term in Sub-Section 6.2.1of this Code;
51. **"Congested Zone"** means an area in the Transmission Network, established as per Sub-Section 6.2.1of this Code, which consists of multiple Congested Areas and can be considered as an independent network having interconnections with other independent networks.;
52. **"Congestion"** means a state of the Transmission or Distribution Network where the dispatch of Generation Units on least cost basis may result in overload of equipment or unstable voltage levels or violation of the reliability and security criteria provided in the Grid Code;
53. **"Connect"** means a form of physical link to the Transmission or Distribution Network and related terms shall be construed accordingly;
54. **"Connection Agreement"** means an agreement for the provision of network services between a Transmission Service Provider or a Distribution Network Service Provider, as the case may be, and a Market Participant or a BPC, or a Generator or an agreement between two network Service Providers;
55. **"Connection Point"** means a point of connection between:
    a) a Transmission or a Distribution Network and a Generation Plant or Generation Unit;
    b) A Transmission Licensee or a Distribution Licensee and a BPC; or
    c) A Transmission Licensee and a Distribution Licensee; or
    d) Two Transmission Licensees or Distribution Licensees; or
    e) A Transmission Licensee or Distribution Licensee and foreign countries or territories where the applicability of the Act is not extended; or
    f) Two Market Participants; or
    g) Any other point within the Transmission or Distribution Networks, which the Market or System Operator considers necessary to be metered for the proper implementation of this Code;
56. **"Contract Market"** means the Bilateral Contracts market established under this Code;
57. **"Contract Register"** means the record organized and maintained by the Market Operator for the quantity of Energy and/or Capacity bought and sold among Market Participants through Contracts;
58. **"Contract Termination Date"** means the termination date of a Bilateral Contract agreed between the parties at the time of registration of the Contract or any other date as approved by the Market Operator;
59. **"Credited Capacity"** means the Capacity allocated to a Market Participant in the Balancing Mechanism for Capacity and/or verification of its compliance with the Capacity Obligations;

60. **"Credit Advice"** means an advice issued by the Market Operator to a Market Participant immediately after issuing a Final Settlement Statement, Final Yearly Settlement Statement, Extraordinary Yearly Settlement Statement or on account of any other adjustment or payment regarding the amount it is entitled to receive through the Market Operator on the Clearing Day or any other date as specified by the Market Operator;
61. **"Critical Hours"** are such hours of the previous year when the power system was under maximum stress ~~and~~ as detailed in Sub-Section 9.2.1;
62. **"CTBCM" or "Competitive Trading Bilateral Contracts Market"** means electric power market established in accordance with the high-level and detailed designs approved by the Authority vide its determinations dated 5th day of December, 2019 and 12th day of November, 2020 as may be amended by the Authority from time to time;
63. **"Customized Contracts"** shall have the meaning assigned to this term in Clause 3.2.2.4;
64. **"Debit Advice"** means an advice, issued by the Market Operator to a Market Participant subsequent to issuing a Final Settlement Statement, Final Yearly Settlement Statement, Extraordinary Yearly Settlement Statement or on account of any other adjustment or payment whereby a Market Participant is required to pay a certain amount to the Market Operator;
65. **"Default Amount"** means any amount a Market Participant/Transmission or Distribution Licensee has failed to pay on a Payment Due Date;
66. **"Default Interest"** means an amount payable by a Market Participant, at a rate as specified in Clause 18.2.6.1, if it fails to fulfil its payment obligations under this Code on the Payment Due Date;
67. **"Default Notice"** means the notice issued by the Market Operator to a Market Participant involved in an Event of Default;
68. **"Demand"** means either the Energy supplied to consumers over a period of time (Energy Demand) or the electric power supplied to consumers at a particular instant (Capacity Demand);
69. **"Demand Forecast"** means an estimate of future Demand typically worked out by using mathematical forecasting techniques and historical Demand data or any other relevant information;
70. **"Designated Account"** means the existing main revenue collection account of the EX-WAPDA DISCO including any other Electric Power Supplier/ DISCO carved out of the Ex-WAPDA DISCOs in the Designated Bank;
71. **"Designated Bank"** means the bank selected jointly be the Market Operator, and the EX-WAPDA DISCO including any other Electric Power Supplier/ DISCO carved out of the Ex-WAPDA DISCOs to operate the Designated Account as per standard instructions given in Clause 12.1.3.6 and the terms and conditions of the agreement entered into for this purpose;
72. **"Dispatch"** shall have the meaning assigned to the term in the Grid Code.
73. **"Dispatch Day"** means a period in the Dispatch process from 00.00 hours to 23.59 hours in the same calendar day;
74. **"Dispatch Instruction"** means the operating instruction issued by the System Operator to a Generation Unit for its Dispatch in accordance with the provisions of the Grid Code;

75. **"Dispatch Period"** means every sixty-minute interval, or such other shorter interval as provided in the Grid Code, during a Dispatch Day;
76. **"Dispatchable Generation Unit"** means a Generation Unit which can be controlled for increasing or decreasing its production following manual or automatic instructions issued by its operator. For the avoidance of doubt, these Generation Units shall not include the variable renewable generation technologies such as wind and solar and run of river hydro based Generation Units without any significant storage;
77. **"Dispute"** means any dispute or disagreement or difference arising under this Code or any provision hereof as specified in Chapter 14;
78. **"Distribution Company" or "DISCO"** means a distribution company Licensed by the Authority to engage in the distribution of electric power;
79. **"Distribution Code"** means the distribution code prepared by the Distribution Licensees and approved by the Authority;
80. **"Distribution Network"** means distribution and transmission facilities owned, operated, managed or controlled by a DISCO and used for the movement or delivery of electric power;
81. **"Distribution Network Connected Generation"** means a Generation Plant or Generation Unit directly connected to a Distribution Network;
82. **"Distribution Network Service Provider"** means a Distribution Licensee which provides, inter alia, Open Access;
83. **"Early Contract Termination"** means the termination of a Contract with the consent of the parties on a date prior to the one recorded in the Contract Register;
84. **"Effective Date (of a Contract)"** means the date from which the registered Contract is used in the balancing mechanisms or for verification of the Compliance with Capacity Obligations;
85. **"Electric Power Supplier"** shall include competitive supplier and supplier of last resort;
86. **"Electric Power Trader"** means a person Licensed by the Authority under section 23C of the Act;
87. **"Electronic Local Meter Reading"** means obtaining the values stored in the internal memory of the Meter, by making a physical link between such Meter and a portable electronic equipment capable to download such information;
88. **"Energy"** means electrical energy produced by Generation Plants or Generation Units, flowing through or supplied by Transmission Network or Distribution Network, measured in units of watt-hours or standard integers or multiples thereof;
89. "**Energy Balancing Period**" shall have the meaning assigned to the term in Clause 5.1.2.1:
90. **"Energy Limited Generation Unit"** means a Generation Unit whose capability to produce Energy is constrained by the availability of the primary energy stored;
91. **"Enrolled Person"** means a person who is enrolled with the Market Operator as per provisions of Section 2.10 of this Code;
92. **"Equivalent Availability Factor"** means the fraction of Dependable Capacity, averaged over a year, that a Generation Unit is able to provide after considering all types of outages and deratings;
93. **"Export"** means the selling/delivery of Energy and/or Capacity to foreign countries or such territories where the applicability of the Act is not extended;

94. **"Extraordinary Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 7.3.4;
95. **"Extraordinary Yearly Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 11.3.4
96. **"EX-WAPDA DISCO"** means a DISCO which has been formed as the result of un-bundling of WAPDA or any subsequent unbundling of the same;
97. **"Final Settlement Statement"** shall have the meaning assigned thereto in Sub-Section 7.3.3;
98. **"Final Yearly Settlement Statement"** shall have the meaning assigned thereto in Sub-Section 11.3.3;
99. **"Firm Capacity"** means the portion of the Dependable Capacity of a Generation Plant, which is available to be delivered with a high degree of probability at the System Peak Hours;
100. **"Firm Capacity Certificate"** means a certificate issued by the Market Operator to:

    a) a Generator allowing it to sell Capacity under a Bilateral Contract up to the amount provided in the certificate or complying with its Capacity Obligations;

    b) EX-WAPDA DISCOs for Legacy Contracts-CPPA-G or Legacy Contract-DISCO, as the case may be; or

    c) KE for its own Generators or Legacy Contracts-KE.

101. **"Firm Export"** means an Export which may not be interrupted even where the total Available Capacity is less than the potential electric power demand in Pakistan;
102. **"Fiscal Year"** means a period of twelve (12) months starting from 1st July and ending on 30th June;
103. **"Forced Outage Rate (FOR)"** means the rate, expressed in percentage on annual basis, of full or partial interruption in the capability of a Generation Plant to inject Energy into the Grid System due to technical fault in the machinery/equipment. For the avoidance of doubt, this value for Legacy Generators shall not include other force majeure events due to non-availability of fuel;
104. **"Generate" or "Generation"** means the production of Energy at a Generation Unit or a Generation Plant and its delivery to the Transmission or Distribution Network;
105. **"Generation Company"** means a person which is issued a Generation Licence or has concurrence of the Authority to construct, own or operate a Generation facility;
106. **"Generation Following Supply Contract"** shall have the meaning assigned to the term in Section 3.3.1;
107. **"Generation Plant"** means a Generation Unit or group of Generation Units, connected to the Transmission or Distribution Network at a single Connection [redacted];
108. **"Generation Unit"** means a conversion apparatus including auxiliaries and associated equipment, used to produce electric power from some other form of energy, which is dispatchable as an indivisible unit or a group of such indivisible units, as the case may be;
109. **"Generator"** means a Generation Company or a Captive Generator, as the case may be;
110. **"GoP"** means the Government of the Islamic Republic of Pakistan;

111. **"Grid Code"** means the grid code prepared and maintained by the System Operator pursuant to sections 23G and 23H of the Act and approved by the Authority;

112. **"Grid System"** means the Transmission and Distribution Network owned and operated by the Transmission and Distribution Licensees;

113. **"Guarantee Amount"** means financial security provided by Market Participants, which shall be used in case the Security Cover is insufficient for monthly Settlement. The Guarantee Amount will be determined and maintained as per Chapter 13;

114. **"Guaranteed Capacity"** shall have the meaning assigned to the term in Clause 3.2.1.5;

115. **"Identification Code"** is an alphanumerical code which precisely and uniquely identifies (i) a Market Participant, or (ii) a Generation Plant or Generation Unit, or (iii) a Metering Point, as the case may be, which will be assigned:

   a. by the Market Operator to the Market Participants during the enrolment process;
   b. by the System Operator to the Generation Plants or Generation Units according to the provisions of the Grid Code; and
   c. by the Metering Service Provider to the Metering Points;

116. **"Imbalance"**

   a. If used in relation to Capacity, shall mean either the difference between the Capacity sold through a Contract (registered with the Market Operator) and the actual Available Capacity; or the difference between the Capacity purchased through a Contract (registered with the Market Operator) and the actual Maximum Demand in the relevant period taken from the Transmission or Distribution Network, as the case may be;
   b. If used in relation to Energy, shall mean the difference between the Energy quantities bought and sold through a Contract (registered with the Market Operator) and the actual quantities injected into or withdrawn from the Transmission or Distribution Network, determined as per provisions of Chapter 5 of this Code;

117. **"Import"** means procurement of Energy and/or Capacity from foreign countries and from Generation Plants located in the territories where the applicability of the Act is not extended;

118. **"Initial Firm Capacity Certificate"** means the Firm Capacity Certificate issued by the Market Operator:

   a. Before CMOD, for those Generation Plants which were existing prior to the CMOD;
   b. At the time of commissioning, for those Generation Plants which are commissioned after CMOD;

119. **"Installed Capacity"** at reference site conditions, means the amount of electric power that a Generation Unit or a Generation Plant is designed to operate on a continuous basis and determined through the commissioning or any other tests specifically designed for such purpose.;

120. **"Dependable Capacity"** means the share of the Installed Capacity which a Generation Unit or Generation Plant is able to deliver to the Transmission or Distribution Network. The values shall be equal to:

a. For Legacy Generators-CPPA-G except solar and wind based Generation Plants, the dependable capacity as determined through the initial/annual dependable capacity tests performed and notified by the SPA.
b. For solar and wind based Legacy Generators-CPPA-G, Legacy Generators-DISCO and Legacy Generators-KE, the figures as provided by the SPA, EX-WAPDA DISCO or KE as per the Legacy Contracts-CPPA-G, Legacy Contracts-KE or Legacy Contracts-DISCOs, as the case may be.
c. For other Generators, the value certified by the System Operator as per provisions of the Grid Code.
d. For Captive Generators installed before CMOD, value certified by a credible independent engineer, approved by the System Operator;

121. **"K-Electric" or "KE"** means K-Electric Limited Licensed by the Authority;
122. **"Legacy Contract-CPPA-G"** means:
   a. a PPA or EPA (including International Interconnection Agreements (import/export), off-take arrangements with WAPDA and NTDC) which are signed or administered by the CPPA-G before the CMOD;
   b. a PPA or EPA (including International Interconnection Agreements (import/export) to be signed in the future for any other projects which are considered committed for EX-WAPDA DISCOs in the latest IGCEP approved by the Authority before CMOD;
123. **"Legacy Contract-DISCOs"** means a PPA or EPA signed or administered by any of EX-WAPDA DISCO before the CMOD;
124. **"Legacy Contract-KE"** means a PPA or EPA signed and administered by KE before the CMOD.
125. **"Legacy Generator-CPPA-G"** means a Generator or an Import contracted through a Legacy Contract-CPPA-G.
126. **"Legacy Generator-DISCOs"** means a Generator or an Import contracted through a Legacy Contract-DISCO.
127. **"Legacy Generator-KE"** means a Generator or an Import contracted through a Legacy Contract-KE.
128. **"Licence"** shall have the meaning assigned to the term in the Act and the word "Licensee" shall be construed accordingly;
129. **"Load Facility"** means a facility that consumes Energy;
130. **"Load Following Supply Contract"** shall have the meaning assigned to the term in Section 3.3.3;
131. **"Manual Local Meter Reading"** means obtaining the values stored in the internal memory of the Meter by visual inspection of the values shown on the Meter display;
132. **"Market"** means the Competitive Trading Bilateral Contracts Market (CTBCM);
133. **"Market Settlement System"** means a system set up and administered by the Market Operator consisting of information processing and communication systems in order to perform the functions as provided in Sub-Section 7.2.2;
134. **"Market Operator"** means the person Licensed by the Authority to perform the functions of the Market Operator;
135. **"Market Operator Fee"** means the fee determined by the Authority for the Market Operator services;
136. **"Market Participant"** means any person who is enrolled with the Market Operator and has also executed a Market Participation Agreement;

137. **"Market Participants Register"** means the register organised and maintained by the Market Operator with the enrolment information of Market Participants, as defined in Chapter 2;
138. **"Market Participation Agreement"** means the agreement executed by the Market Operator with another person who had applied to enrol as a Market Participant;
139. **"Market Transactions"** means those transactions in the Market which shall be applicable only after the CMOD. Such transactions include Balancing Mechanism for Energy and Capacity, payment settlements, compensation for Transmission Must Run, Reliability Must Run and Ancillary Services, Operator's Fee and verification of compliance with Capacity Obligations;
140. **"Maximum Demand"** means maximum amount of electric power demanded by a Market Participant on coincidental basis through all of its Connection Points, averaged over a (30 minutes) period, expressed in Watts or its standard multiples;
141. **"Meter"** means a device that measures electrical energy as per specifications of the Grid Code or Distribution Code, as the case may be;
142. **"Metering Incident Report"** means a report prepared by the Metering Service Provider in the cases provided in Clauses 4.3.2.2 and 18.2.2.5;
143. **"Metering Point"** means a Connection Point, equipped with a Commercial Metering System which is periodically read by an authorised Metering Service Provider;
144. **"Metering Service Provider" or "MSP"** means an entity responsible for the organization and administration of the Commercial Metering System and performing the functions of meter reading and validation at Metering Points and transferring those values to the Market Operator and other relevant parties;
145. **"Minor Non-Compliance"** shall have the meaning assigned to the term in Clause 10.5.4.6;
146. **"MO Website"** means the online system established by the Market Operator on the world-wide web for the exchange of information amongst the System Operator, the Market Operator, the Service Providers, Market Participants, and other interested parties in accordance with such restrictions on access as may be required under the provisions of this Code;
147. **"Must Stop Generation"** in a particular Dispatch Period, means a Generation Unit having Variable Generation Cost lower than the System Marginal Price and is not dispatched or is dispatched at a value lower than its Available Capacity in order to alleviate Congestion;
148. **"National Transmission and Despatch Company Limited" or "NTDC"** means the national grid company Licensed by the Authority;
149. **"Non-dispatchable Generation Unit"** means a Generation Unit whose actual production, at a given time, is dependent on the availability of primary resource which is subject to uncontrollable meteorological or hydrology factors;
150. **"Notice of Dispute"** shall have the meaning assigned to the term in Clause 14.3.1.1;
151. **"Open Access"** shall mean provision of connection and non-discriminatory use of transmission and distribution facilities of a transmission or distribution licensee against payment of such charges and on such terms and conditions as may be determined by the Authority;

152. **"Payments Calendar"** means the calendar prepared by the Market Operator indicating the dates for issuing the Preliminary and Final Settlement Statements (monthly and yearly), and the Debit Advices for the whole Fiscal Year;

153. **"Payment Due Date"** means the date of the second (2^{nd}) Business Day after the issuance of the Debit Advice or provided otherwise for payment of a specific amount under a Debit Advice;

154. **"Permanent Firm Capacity Certificate"** means a Firm Capacity Certificate granted pursuant Clause 8.3.1.7 that can be used to register Contracts with the Market Operator involving Capacity transactions;

155. **"Physical Asset"** for the purposes of this Code, means a Generation Unit of a Generation Plant which is clearly identified;

156. **"Preliminary Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 7.3.1;

157. **"Preliminary Yearly Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 11.3.1;

158. **"Power Acquisition Programme"** means a plan prepared by a Supplier of Last Resort or a joint plan prepared by several Suppliers of Last Resort in coordination with the Independent Auction Administrator, as the case may be, in accordance with the provisions of the relevant regulations of the Authority;

159. **"Record"** means an information, data, documents or any similar object in nature, produced or received by the Market Operator which shall be kept in writing or any other permanent form;

160. **"Reduced Generation Compensation"** means a compensation that a Generator is entitled to receive for the revenue loss, on account of reduction in the Energy dispatched as per the instructions issued by the System Operator:
    a. for providing Ancillary Services; or
    b. allowing the provision of Ancillary Services by other Generation Units;

161. **"Reference Technology"** shall have the meaning assigned to the term in Clause 9.2.6.10;

162. **"Reliability Must Run"** in a particular Dispatch Period means a Generation Unit which has been dispatched by the System Operator in order to satisfy the system security and reliability criteria as specified in the Grid Code;

163. **"Renewed Firm Capacity Certificate"** means a Firm Capacity Certificate which has been re-issued by the Market Operator due to the expiration of a previous Firm Capacity Certificate;

164. **"Reserve Margin"** shall have the meaning assigned to the term in Clause 9.2.4.3;

165. **"Review Request"** means a request lodged by a Market Participant with the Market Operator for review of the results of the BME, BMC, Preliminary or Final Settlement Statements (monthly or yearly), or the verification of compliance with the Capacity Obligations on the grounds that there exist errors, inaccuracies or wrong interpretations in any of the said documents;

166. **"Section"** means a section of this Code;

167. **"Secured Metering System" or "SMS"** means the information technology based system, including hardware, software and communication channels, which retrieves information from the Commercial Metering System and transfers it electronically to the System Operator, relevant Market Participant and Market Operator, at specified times;

168. **"Security Constrained Economic Dispatch" or "SCED"** shall have the meaning assigned to the term in the Grid Code;
169. **"Security Cover"** means advance financial security against the monthly Settlement transactions of a Market Participant, and will be provided and maintained by a Market Participant in the form and amount as specified in Chapter 13;
170. **"Self-dispatch"** means an operative condition in which the Generator decides, by itself, the amount of Energy that may be produced by the Generation Unit, without a specific instruction of the System Operator in this regard. For the avoidance of doubt, Generators which are exempted from being controlled by the System Operator, as per the provisions of the Grid Code, are not considered as being self-dispatched;
171. **"Serious Non-Compliance"** shall have the meaning assigned to the term in Clause 10.5.4.6;
172. **"Service Provider"** means a person who may provide regulated services necessary for market or system functioning, and is not enrolled as a Market Participant such as Transmission Service Provider, Distribution Network Service Provider, Metering Service Provider excluding the System Operator and Market Operator;
173. **"Service Provider Agreement"** means the agreement executed between the Market Operator and a Service Provider to enrol it as Service Provider with the Market Operator;
174. **"Settlement"** means the process of calculating charges to be paid by and to Market Participants or Service Providers under this Code;
175. **"Settlement Guarantee Cover"** means the Guarantee Amount deposited by a Market Participant;
176. **"Settlement Period"** means a period of time for calculating the charges of the Imbalances associated with commercial transactions among Market Participants which is specified as one calendar month for Energy, one Fiscal Year for Capacity or any other shorter period of time as may be determined by the Market Operator with the approval of the Authority. The Settlement Period for Ancillary Services shall be the same as the Settlement Period for Energy;
177. **"Settlement Software"** means the suite of computer programmes used by the Market Operator to calculate the Settlement amounts under this Code;
178. **"Settlement Statement"** means the document prepared by the Market Operator which specifies the amount to be paid to or received by each Market Participant or Service Provider under this Code;
179. **"Special Purpose Agent"** means the functions of the CPPA-G, which deals with the administration of the Legacy Contracts-CPPA-G as an agent of the Ex-WAPDA DISCOs and KE, in their role as Electric Power Suppliers as per its registration with Authority as Market Operator under the Market Rules 2015 before CMOD or its registration with the Authority under section 25A of the Act after CMOD;
180. **"Standardized Contracts"** shall have the meaning assigned to the term in Clause 3.2.2.2;
181. **"Sub-Section"** means a Sub-Section of this Code;
182. **"Supplier of Last Resort"** means a person who holds an electric power supply license for the service territory specified in its licence and is obligated to supply electric power to all consumers located in that service territory at the rates determined by the Authority and is also obligated to provide electric power supply

to the consumers, located within its service territory, of any competitive supplier who defaults on its obligations of electric power supply;

183. **"Supply License" or "Electric Power Supply License"** means a License issued by the Authority under section 23E of the Act;

184. **"Suspended Participant"** is any Market Participant who has received and is the subject of a valid and continuing Suspension Order;

185. **"Suspension Order"** means an order issue by the Market Operator pursuant to Sub-Section 16.2.2;

186. **"System Marginal Price"** means the Variable Generation Cost of the most expensive Generation Unit which would be dispatched to supply one (1) additional MW of Demand as determined pursuant to the relevant methodology developed by the System Operator according to Clause 5.6.1.2 or until such time the methodology according to Clause 5.6.1.2 is developed and approved by the Authority, the transitory methodology stipulated in Section 19.1 shall be used as an interim measure for this purpose;

187. **"System Operator"** means a person licenced by the Authority under section 23 G of the Act;

188. **"System Operator Fee"** means the fee determined by the Authority for the System Operator;

189. **"System Peak Hours"** means the hours included in the period from, 1200 hrs to 1700 hrs and 2100 hrs. to 0100 hrs. for the months of June, July, August, and September;

190. **"Tariff Determination"** means a determination whereby the Authority approves tariff, rates, charges and other terms and conditions for provision of electric power services;

191. **"Temporary Firm Capacity Certificate"** means a Firm Capacity Certificate issued by Market Operator pursuant to Clause 8.3.1.4 that can be used as a proof of commitment during the verification process for compliance with the Capacity Obligations and/or to obtain financing for a project, but cannot be used to back up Capacity transaction in a Bilateral Contract which has to be registered with the Market Operator;

192. **"Terminated Market Participant"** means a Market Participant whose enrolment as Market Participant has been revoked and its authorisation to participate in the Market has been terminated pursuant to a Termination Order;

193. **"Termination Date"** means the date on which a Market Participation Agreement expires or the same is terminated by the Market Operator;

194. **"Termination Order"** means an order issued by the Market Operator pursuant to Clause 16.2.3.1;

195. **"Total Demand"** means the total Demand of the system, calculated pursuant to the provisions of Sub-Section 6.3.2;

196. **"Trading Period"** means the period for which an Energy transaction or a Capacity transaction is allowed as defined in Clause 3.2.1.2;

197. **"Trading Point"** means a Metering Point at which commercial transactions (buying or selling of Energy or Capacity) may take place;

198. **"Transmission Licensee"** means a person Licensed by the Authority under sections 16, 17, 18A or 19 of the Act;

199. **"Transmission Must Run"** in a particular Dispatch Period means a Generation Unit which has been dispatched by the System Operator in order to alleviate Congestion;

200. **"Transmission Network"** means transmission facilities owned, operated, managed or controlled by a transmission licensee and used for the movement or delivery of electric power;

201. **"Transmission Service Provider" or "TSP"** means the holder of a Transmission License issued by the Authority and is enrolled with the Market Operator;

202. **"Urgent Amendment"** shall have the meaning as assigned to the term as per Clause 1.3.7.1;

203. **"Validation Checks"** means the set of evaluations, checks or verifications which are performed by a Metering Service Provider to determine the appropriateness of a metered value obtained through the Commercial Metering System;

204. **"Variable Generation Cost"** means the costs which vary with the change of the output of a Generation Unit; and

205. **"Variable Generation Cost List"** means the table, prepared by the System Operator, containing list of all Generation Units and Imports associated with specific Generators, organized in ascending order of their Variable Generation Cost.

1.2.1.2. The words and expressions used but not defined in this Commercial Code shall have the same meaning as are assigned to them in the Act.

1.2.2. INTERPRETATION

1.2.2.1. In case of any inconsistency or contradiction of the provisions of this Code with the Act, or rules and regulations made thereunder, the provisions of the Act or the rules and regulations, as the case may be, shall prevail to the extent of inconsistency or contradiction.

1.2.2.2. In this Code, unless the context otherwise requires:

a) a reference to a particular Part, Chapter, Section, Sub-Section, Clause, or Appendix is to a Part, Chapter, Section, Sub-Section, Clause or Appendix of this Code;

b) the table of contents and Chapter, Section or Sub-Section headings are for convenience only and shall be ignored while construing this Code;

c) references to the masculine include the feminine and vice versa and references to the singular include plural;

d) PKR means Pakistani Rupees;

e) the word "include" shall be construed as without limitation;

f) a reference to a "person" includes any individual, partnership, firm, company, corporation (statutory or otherwise), joint venture, trust, association, organisation or other entity, in each case whether or not having separate legal personality;

g) a reference to law or Act or rule or regulation shall be construed to include any amendment, modification, extension, re-enactment or replacement thereof; and

h) a derivative term of any defined or interpreted term or expression shall be construed in accordance with the relevant definition or interpretation;

i) any digit shall be rounded off to four digits of decimal; and

j) if there is any imbalance between the Amounts Payable and Amounts Receivable in the Calculation of Balancing Mechanism for Energy, calculation of compensations for Transmission Must Run, Reliability Must Run and Ancillary Service Charges, execution of the Balancing Mechanism for Capacity due to rounding off issues, the same shall be adjusted against Market Operator Fee. The rounding off error shall not be greater than Rs. 10 in any Settlement Statement.

1.2.3. RIGHT OF INTERPRETATION

1.2.3.1. The Market Operator shall implement, apply, and enforce the provisions of this Code.

1.2.3.2. The Market Operator shall have the right of interpretation of this Code. The Market Operator shall publish all such interpretations on the MO Website. In case of any dispute regarding interpretation of any Part, Chapter, Section, Sub-Section, Clause, Appendix or any other provision of this Code, and subject to dispute resolution mechanism provided in the Code, the matter may be referred to the Authority for interpretation and the interpretation made in such case by the Authority shall be final and applicable on all parties.

1.2.4. TIMES AND DATES

1.2.4.1. For the purposes of this Code, "Business Day" means a day on which the Banks in Islamabad are operational for public dealing.

1.2.4.2. References to times of a day in this Code are to Pakistan Standard Time (PST).

1.3. AMENDMENTS TO THIS CODE

1.3.1. COMMERCIAL CODE REVIEW PANEL

1.3.1.1. There shall be a Commercial Code Review Panel (CCRP), to be established by the Market Operator, whose duties in respect of this Code and the CTBCM include reviewing, proposing and recommending amendments to this Code for approval of the Authority on an on-going basis and making recommendations to the Authority on specific issues related to the operations of the CTBCM.

1.3.1.2. The total strength of CCRP shall consist of thirteen (13) voting members and one (1) observer member to be appointed as provided in Clause 1.3.1.7.

1.3.1.3. In order to convene a meeting, at least 8 members of the total strength of the CCRP shall constitute a quorum, provided that no act or proceeding of the CCRP shall be invalid by reason only of the existence of a vacancy in or defect in the constitution of the CCRP.

1.3.1.4. Decisions of the CCRP shall be taken by the majority of its members present and in case of a tie, the person presiding the meeting shall have a casting vote.

1.3.1.5. Provided that the member specified as independent representative nominated by the Authority shall not have any vote and shall hold the position as an observer.

1.3.1.6. Members of the CCRP shall:

a) have technical or commercial knowledge and expertise in the operation of power systems and electricity markets, and shall not be members of the Market Operator or

System Operator boards;

b) in the case of a member representing Market Participants, Transmission Service Providers, the System Operator or the Market Operator, he shall be a member, officer, employee, or agent of a person in the relevant category which such member represents;

c) in the case of a member representing the Bulk Power Consumers, he shall be a duly authorised representative of registered bodies of such consumers;

d) in the case of a member representing a Market Participant or a Transmission Service Provider or the System Operator or the Market Operator, he/she shall not be a member, officer, employee or agent of a person in another class of a Market Participant or the Transmission Service Provider or the Market Operator or of an Affiliate of such person except in the case of NTDC as Transmission Service Provider and System Operator who may be member, officer, employee or agent of each other until the time the System Operator will be carved out from NTDC, if so decided by the Competent Authorities;

e) not serve for more than two terms as a member of the CCRP.

1.3.1.7. The CCRP shall consist of the following members:

a) One representative of Generation Companies or Licensees other than ARE Producers and hydro power plants.

b) One representative of ARE Generators including hydro power plants;

c) One representative of WAPDA;

d) One representative of the National Grid Company;

e) One representative of the Provincial Grid Companies;

f) One representatives of the EX-WAPDA DISCOs;

g) One representative of KE;

h) One representative of the Competitive Suppliers;

i) One representative of the Bulk Power Consumers;

j) One representative of the Electric Power Traders;

k) One representatives of the System Operator;

l) One representatives of the Market Operator;

m) One representative of Special Purpose Agent;

n) One representative nominated by the Authority as an observer, without voting rights;

1.3.1.8. Nomination of the CCRP members shall be as follows:

a) The representative of Generation Companies and Licensees and ARE Generators shall be appointed by the Association of Generators;

b) The representative of WAPDA shall be appointed by WAPDA;

c) The representative of the Transmission Service Providers shall be nominated by NTDC;

d) The representative of the Provincial Grid Companies shall be nominated by the relevant Provincial Grid Companies on rotation basis in the following order: the Province of Sindh, Khyber Pakhtunkhawa, Balochistan and Punjab;

e) The representative of the Ex-WAPDA DISCOs shall be nominated by the Association of

Distribution Companies;

f) The representative of K-Electric shall be nominated by K-Electric;

g) The representative of the Competitive Electric Power Suppliers shall be nominated by the Association of Competitive Electric Power Suppliers;

h) The representative of the Bulk Power Consumers shall be appointed by the Association of Bulk Power Consumers;

i) The representative of the Traders shall be appointed by the Association of Traders;

j) The representatives of the System Operator shall be appointed by NTDC or by the relevant company, in case the System Operator is carved out from NTDC;

k) The representatives of the Market Operator shall be appointed by the Market Operator; and

l) The representatives of the Special Purpose Agent shall be appointed by the CPPA-G.

1.3.1.9. Until the Association of Independent Power Producers, the Association of Distribution Companies, the Association of Competitive Suppliers, the Association of Bulk Power Consumers and the Association of Traders are constituted and become operative, then subject to Clause 1.3.1.10, the Market Operator shall, in consultation with the enrolled Market Participants (i.e. the Market Participants will submit (three names) of the proposed representatives for the respective Market Participant type) nominate the representatives of the initial CCRP.

1.3.1.10. In case no association exists and there are no enrolled Market Participants that represent the type of members as mentioned in Clause 1.3.1.9, then then such member shall be nominated by the Authority .

1.3.1.11. The representative of the Market Operator shall be the chairperson of the CCRP.

1.3.1.12. The term of each member of the CCRP shall be three years. A member of the CCRP, whose term has expired, shall be eligible for re-nomination for a further term of three years.

1.3.2. Commercial Code Report

1.3.2.1. Every year, the Market Operator shall prepare a Commercial Code Report (CC Report), describing the problems experienced by the Market Operator and/or the System Operator during the implementation of the Commercial Code and the relevant CCOPs, as well as the list and description of interpretations made by the Market Operator. The Market Operator shall submit such report to the Authority as well as publish it on MO Website.

1.3.2.2. The CC Report shall include:

a) statistics of transactions in the market;

b) problems identified in the implementation of the Commercial Code, and the CCOPs;

c) interpretations made for this Code by the Market Operator, and any conflicts of interpretation of this Code with Market Participants or Service Providers;

d) any transitional exception granted to a Market Participant in complying with the Commercial Code or the CCOPs, and the reasons thereof, and inform when a transitional exemption has ended; and

e) any other relevant matter to identify any problems in the performance, feasibility, efficiency and design of this Code.

1.3.3. COMMERCIAL CODE WORKING GROUP

1.3.3.1. The Market Operator shall set up a Commercial Code Working Group (CCWG), as a permanent advisory group to assist the CCRP in performing its functions. The Market Operator or the CCRP, as the case may be, may assign tasks to the CCWG to assess any problem or gap in the Commercial Code including the operational procedures.

1.3.3.2. The CCWG shall include members from the System Operator and the Market Operator or if required, any other technical experts from the market or other relevant organizations.

1.3.3.3. The CC Working Group may propose to the CCRP:

a) to accept or review an amendment proposal that has been presented to the CCRP;

b) Amendments to correct, complete or improve the Commercial Code; and

c) new or updated CCOPs for implementation of the Commercial Code.

1.3.4. PROCEDURE FOR REVIEW OR AMENDMENT OF COMMERCIAL CODE

1.3.4.1. The System Operator, a Service Provider, a Market Participant, the CCWG or any other interested person may propose in writing to review or amend a provision of this Code (the "Amendment Submission") to the Market Operator, accompanied with a statement of reasons.

1.3.4.2. The Market Operator shall submit to the CCRP the Amendment Submission, with the identification of the person who submitted it. The CCRP may direct the person who submitted the Amendment Submission to provide further information as may be required.

1.3.4.3. If the Amendment Submission is not proposed by the CCWG, the CCRP may refer the Amendment Submission to the CCWG for review and submission of its opinion thereon.

1.3.4.4. While considering an amendment to this Code, the CCRP shall take into consideration the recommendations of the CCWG.

1.3.4.5. Within thirty (30) Business Days of receipt of the Amendment Submission, the CCRP shall respond in writing whether the Amendment Submission, in the opinion of the CCRP:

a) warrants further consideration; or

b) does not require consideration in accordance with Clause 1.3.4.14.

1.3.4.6. Where the CCRP decides to further process the Amendment Submission, it shall publish it on the Market Operator website, and give notice to all Market Participants and Service Providers of the contents of the Amendment Submission. The website publication and notice shall invite Market Participants and other interested persons, to make, within such reasonable period as shall be specified in the notice, which shall not be shorter than ten (10) Business Days, written submissions concerning the Amendment Submission. The notice shall also include an electronic address for submission of comments.

1.3.4.7. The CCRP may, at any time direct the person who made the Amendment Submission, the Market Participants or other interested persons:

a) to make such additional written submissions within such reasonable time as the CCRP deems appropriate; or

b) schedule and hold meetings with the person who made the Amendment Submission, Market Participants and other interested persons who filed a written submission.

1.3.4.8. The CCRP shall provide notice of meetings to any relevant Market Participant or other interested persons, to participate in the meetings.

1.3.4.9. The CCRP shall, as soon as reasonably practicable, consequent to any meetings and consultation sessions which may have been held, convene one or more meetings of its members, as may be necessary, to consider and vote on the Amendment Submission. The CCRP shall consider all submissions, received by it within the specified time.

1.3.4.10. Following the conclusion of the deliberations and meetings of CCRP, if an Amendment Submission is recommended to be submitted to NEPRA for review and approval, as originally proposed or with any modifications, the CCRP shall prepare a report which includes:

a) the recommendations of the CCRP regarding the Amendment Submission and the analysis and the reasons thereof;

b) where the recommendations of the CCRP include a proposal to amend the Code, a copy of the proposed text of the Amendment, the suggested time of commencement of the Amendment, and a summary of any objections to the Amendment Submission which may have been raised through written submissions or brought to the attention of the CCRP during any meetings;

c) a summary of the procedure followed by the CCRP in considering the matter, including list of meetings held with parties, scope and general objectives;

d) a record of the vote of each member of the CCRP in respect of each of the recommendations made in the report; and

e) a summary of any objections raised by any member of the CCRP to the recommendations, if so requested by the said member.

1.3.4.11. Upon completion of the report referred to in Clause 1.3.4.10, the CCRP shall refer the matter to the Market Operator for onward submission to the Authority for approval of the recommendations.

1.3.4.12. The Market Operator may publish the recommendations contained in the report referred to in Clause 1.3.4.10 and give notice thereof to all relevant Market Participants, Service Providers and to the person or persons who made the Amendment Submission, provided that Confidential Information will not be disclosed unless authorized by the relevant party.

1.3.4.13. The Market Operator shall publish on its website, copies of all submissions received pursuant to Clause 1.3.4.5 or 1.3.4.6, together with the report prepared by the Market Operator along with the details of any further submissions which were made before the CCRP in accordance to Clause 1.3.4.10.

1.3.4.14. The CCRP may reject the proposed Amendment if, in its opinion and with adequate justification, the proposed Amendment:

a) unfairly discriminates against a Market Participant or class of Market Participants;

b) will limit, and not advance, competition, or prevent open entry into the wholesale competitive market;

c) may allow one or more Market Participants to possess market power;

d) may have a potential for abuse of market power by one or more Market Participants;

e) is not conducive to efficient and economic operation of the wholesale competitive market;

f) materially alters the framework of the CTBCM; or

g) is not consistent with the Applicable Law or policy of the GoP.

1.3.4.15. Where the Authority:

a) approves the proposed Amendment to this Code, the Market Operator, within 5 business days after receiving decision of the Authority, shall publish such decision on the MO Website, together with a copy of the Amendment, and shall give notice of the decision to all Market Participants, Service Providers and the person who proposed the Amendment Submission. The Market Operator shall update the Code accordingly and make an updated copy of the Code available on its website.

b) rejects the proposed Amendment to this Code, the Market Operator shall publish such decision on the MO Website and disseminate it to all Market Participants, Service Providers and the person who proposed the Amendment Submission.

c) sends back the proposed Amendment with comments, the CCRP shall assess the comments and revise the Amendment accordingly to resubmit it to the Authority for approval.

1.3.5. AMENDMENTS INITIATED BY THE CCRP

1.3.5.1. Where the CCRP on its own motion or upon recommendations of the CCWG determines at any time that an Amendment to or a review of the Commercial Code is necessary, it shall issue a notice (the "Review Notice") in this respect together with the reasons thereof to the Market Participants and other interested persons to make written submissions within a specified period. Such Review Notice shall also be published on MO Website and shall contain an electronic address to submit comments.

1.3.5.2. The procedure set out in Clauses 1.3.4.6 to 1.3.4.15 shall, *mutatis mutandis*, apply to the Review Notice.

1.3.6. AMENDMENTS INSTRUCTED BY THE AUTHORITY

1.3.6.1. Where the Authority under section 23B (3) of the Act directs the Market Operator to make an Amendment in the Commercial Code, the Market Operator shall refer the said Amendment to the CCRP immediately but not later than two Business Days.

1.3.6.2. The CCRP shall analyse the proposed Amendment and in case there is no cause to object the Amendment, it will introduce an Amendment to the Commercial Code as directed by the Authority and direct the Market Operator to submit the same for final approval of the Authority. Once approved by the Authority, the Market Operator shall publish the Amendment on its website as mentioned in Clause 1.3.4.15 and implement the same.

1.3.6.3. Where the CCRP considers that there is a just cause not to adopt the Amendment as directed by the Authority, it shall prepare its recommendations before expiry of 30 days from the date of receipt of direction of the Authority to the MO in this respect and instruct the Market Operator to submit the same to the Authority.

1.3.6.4. In case the Authority does not agree with the cause provided by the Market Operator under Clause 1.3.6.3 and directs the Market Operator to implement the Amendment as initially instructed or with modification, the Market Operator shall implement the Amendment as per procedure in Clause 1.3.6.2 above.

1.3.7. URGENT AMENDMENTS

1.3.7.1. An Urgent Amendment may be proposed by the CCRP or recommended by the CCWG to the CCRP, with adequate justification, in the following cases:

a) to avoid, reduce or mitigate the risks of abusing market power;

b) to correct errors in formula and/or detailed data;

c) to modify the provisions of this Code which are contradictory or inconsistent with the rules or regulations framed under the Act where it is impossible to comply with such rules and regulations by following the normal procedure;

d) to avoid, reduce or mitigate unintended adverse effects of a provision of this Code.

1.3.7.2. Where the CCWG submits a document recommending and justifying an Urgent Amendment to the CCRP, the CCRP shall convene, within seven (7) Business Days, a meeting to consider the proposed Amendment and either:

a) recommend the Urgent Amendment, in the form proposed by the CCWG or with necessary modifications, in a document with the assessment and justification; or

b) reject the proposed Urgent Amendment with reasons.

1.3.7.3. Where an Urgent Amendment is recommended by the CCRP, it shall instruct the Market Operator to submit the document with the proposed Urgent Amendment and its justification, for consideration and approval of the Authority.

1.3.7.4. Where an Urgent Amendment is approved by the Authority, the Market Operator shall forthwith publish such Urgent Amendment on the MO Website and shall also inform all the Market Participants and Service Providers. The Market Operator shall update the Code accordingly.

1.3.8. PREPARATION AND AMENDMENT OF THE CCOPS

1.3.8.1. Any new CCOP prepared under the provisions of this Code shall be submitted to the Authority for its information before implementation.

1.3.8.2. The CCOPs shall be prepared within the timelines as stipulated in this Code, however, if any specific timeline is not stipulated, the same shall be prepared within 30 Business Days of approval of this Code.

1.3.8.3. Any CCOP prepared under the provisions of this Code shall be consistent with this Code. If there is any inconsistency, the Code shall prevail to the extent of the inconsistency.

1.3.8.4. If an Amendment is required to an existing CCOP, the same shall be prepared by the Market Operator, or by the System Operator or the Metering Service Provider in collaboration with the Market Operator, as the case may be.

1.3.8.5. Any new CCOP or Amendment to an existing CCOP pursuant to Clause 1.3.8.4, shall be approved by the CCRP before implementation.

Chapter 2. ENROLMENT OF MARKET PARTICIPANTS AND SERVICE PROVIDERS

2.1. MARKET PARTICIPANT ELIGIBILITY REQUIREMENTS FOR ENROLMENT

2.1.1.1. Any person who intends to buy or sell electric power (Energy and/or Capacity), or to participate in the CTBCM, unless exempted under this Code, shall enrol as a Market Participant with the Market Operator, in accordance with the provisions of this Chapter.

2.1.1.2. Following Categories of Market Participants shall be entitled to participate in the CTBCM:

a) Generation Companies

b) Captive Generators

c) Electric Power Suppliers

d) Electric Power Traders

e) Bulk Power Consumers

2.1.1.3. Following persons are exempted from enrolment as Market Participants to participate in the CTBCM:

a) A Generator, connected to a Distribution Network at the distribution voltage which does not fall in the scope of the Grid Code, and sells all its Capacity and Energy to an Electric Power Supplier or an Electric Power Trader;

b) A Generator selling its Energy and/or Capacity through a Legacy Contract-CPPA-G, Legacy Contract-DISCOs or Legacy Contract-KE, as the case may be;

c) In case of Imports, the seller in the Contract;

d) In case of Exports, the buyer in the Contract;

e) A Bulk Power Consumer in case it decides to buy both its Energy and Capacity from the relevant Supplier of Last Resort or it decides to sign a Standardized Load Following Supply Contract with a Competitive Supplier, as per the conditions stipulated in Sub-Section 3.3.3.

2.1.1.4. Any person who has been granted an exemption from enrolment as a Market Participant as per Clause 2.1.1.3 above, may enrol as a Market Participant.

2.1.1.5. A person desirous to enrol as a Market Participant to participate in the Market shall fulfil the following requirements:

a) the person:

a.1. if the application is to enrol as Generator, shall have a generation License or a concurrence has been issued by the Authority to this effect and shall have obtained the necessary Permanent Firm Capacity Certificates from the Market Operator;

a.2. if the application is to enrol as Electric Power Supplier, shall have an Electric Power Supplier License;

a.3. if the application is to enrol as Electric Power Trader, shall have an Electric Power Trader Licence; or

a.4. owns and operates Captive Generating Plant; or a.5. is a BPC;

b) in case of enrolling as a Generator or a BPC or their representative, the person has installed a Commercial Metering System at each Connection Point, in accordance with the provisions of the Grid Code or the Distribution Code, as applicable, and has a valid Connection Agreement with the Transmission or Distribution Network Service Provider to which it is connected, provided that at the CMOD, a person who is already connected without a Connection Agreement will be enrolled and will be obligated to submit the Connection Agreement within the next six (6) months after its enrolment date;

c) the person shall submit an Admission Application to the Market Operator which shall be processed as per provisions of this Code.

2.1.1.6. If at any time, a Market Participant ceases to be eligible to be enrolled as a Market Participant in accordance with this Code, the Market Participant shall immediately inform the Market Operator and, as soon as practicable, the Market Operator shall issue a Suspension Order in accordance with this Code.

2.2. Rights and Obligations of the Market Participants

2.2.1.1. A Market Participant generally shall have, *inter alia*, the following obligations:

a) if the Market Participant is a Generator, or is ~~or an Electric Power Trader~~ representing a Generator, provide the Ancillary Services as provided in the Grid Code;

b) submit to the Market Operator, in a timely manner and to the best of its knowledge, the information stipulated in this Code or as may be required under the CCOPs and necessary for the Market Operator to perform its functions, and inform, as soon as possible, any change in such information;

c) pay on or before the Payment Due Date, any Amounts Payable to the Market Operator;

d) maintain a Security Cover and Guarantee Amount as required by the Market Operator as specified in this Code; and

e) maintain a bank account for the administration of the market payment system;

f) fully abide by this Code, as applicable.

2.2.1.2. Each Market Participant shall have, *inter alia*, the following rights:

a) non-discriminatory Open Access to the Transmission and Distribution Networks in accordance with the Grid Code and the Distribution Code;

b) participation in the Balancing Mechanisms for Energy and Capacity;

c) if applicable, compensation for providing Ancillary Services or Transmission Must Run or Reliability Must Run, as provided in this Code;

d) access to the reports and Non-Confidential Information on the website of the Market Operator, that this Code requires to be published as non-confidential;

e) access to the secured portion of the Market Operator website which is exclusive for Market Participants;

f) submission of complaints to the System Operator regarding a function assigned to it under this Code or to the Market Operator in accordance with the procedures provided in this Code.

2.3. PROCEDURES TO BECOME MARKET PARTICIPANT

2.3.1. APPLICATION TO BECOME A MARKET PARTICIPANT

2.3.1.1. The Market Operator shall develop a CCOP which shall include the following:

a) to describe in detail the requirements to enrol a Market Participant and maintain such enrolment;

b) The requisite information and documents to be furnished by the Applicant for each Category of Market Participants;

c) An Admission Application;

d) Detailed procedure for approval and rejection of the Admission Application; and

e) Procedure for modification of the information already submitted by a Market Participant.

2.3.1.2. The Market Operator shall make available on its website the following documents and information in the most updated form:

a) the Admission Application form;

b) the Commercial Code along with CCOPs;

c) draft Standard Market Participation Agreement; and

d) the schedule of fees for processing an Admission Application.

2.3.1.3. Any person interested to become a Market Participant shall submit to the Market Operator:

a) a complete Admission Application;

b) the information required in the CCOP relevant to the admission process;

c) a non-refundable application processing fee as determined by the Market Operator; and

d) where applicable, if the person has facilities already connected to the Grid System, the Transmission or Distribution Connection Agreement or the details thereof, provided that at the start of the CTBCM, the person that is already connected without a Connection Agreement shall be enrolled and will be required to submit the Connection Agreement within the next six (6) months from the date of its enrolment with the Market Operator, or in case the relevant facility is yet to be connected to the Grid System, the signed/executed Transmission or Distribution Connection Agreement or the details thereof.

2.3.1.4. An Applicant who wants to be enrolled in more than one of the Categories defined in Clause 2.1.1.2 shall submit separate application for each Category.

2.3.2. APPLICATION PROCESS

2.3.2.1. Within five (5) Business Days of receipt of an Admission Application along with the supporting information, the Market Operator shall acknowledge the receipt of the application in writing:

a) that it has received the Admission Application, any other documents as required in 2.3.1.3 and the admission CCOP, if any, and the non-refundable processing fee; and

b) if applicable, notify the amount of the Security Cover and Guarantee Amount pursuant to the provisions stated in Chapter 13.

2.3.2.2. Within five (5) Business Days of receipt of notification from the Market Operator pursuant to Clause 2.3.2.1.b), specifying the amount of Security Cover and Guarantee Amount required to be furnished by the Applicant, the Applicant shall furnish to the Market Operator its consent for deposit of the Security Cover and the Guarantee Amount.

2.3.2.3. Within seven (7) Business Days after receipt of consent of the Applicant pursuant to Clause 2.3.2.2, the Market Operator shall inform the Applicant:

a) that the Admission Application is deficient, and the Applicant is required to provide certain information or documents and return the application; and/or

b) that it is required to supply such additional information or documents; and/or

c) if applicable, the metering system installed by the Applicant is not in accordance with the provisions of this Code or the Grid Code, and if required, the Applicant has to install additional Commercial Metering System at one or more identified points;

d) if applicable, about its Capacity Obligations as per Clause 10.6.1.1; and/or

e) the Applicant's consent regarding deposit of the Security Cover and Guarantee Amount is defective and not acceptable to the Market Operator.

2.3.2.4. If the Market Operator requests additional information or documents pursuant to Clause 2.3.2.3 or informs the Applicant that it has to install additional Commercial Metering Systems or that the consent for the deposit of the Security Cover and Guarantee Amount is not acceptable, the Applicant shall provide such additional information, documents, or get installed the additional Commercial Metering Systems as per provisions of the Grid Code or Distribution Code (as may be applicable) or submit a revised consent for the deposit of the Security Cover or Guarantee Amount or re-submit the Admission Application after remedying the deficiencies, as the case may be, at the earliest possible date.

2.3.2.5. Where an Applicant does not comply with the request of the Market Operator as required in Clause 2.3.2.4 within three (3) months, the Admission Application shall automatically lapse, however, the Applicant may reapply to the Market Operator after fulfilling all the requirements.

2.3.3. PROCEDURES FOR APPROVAL / REJECTION OF AN ADMISSION APPLICATION

2.3.3.1. If the Applicant fulfils the requirement specified in this Code and the relevant CCOP, the Market Operator shall accept the Admission Application and provide the standardized Market Participation Agreement to the Applicant for execution.

2.3.3.2. If applicable, the Market Operator shall also require that the Security Cover and Guarantee Amount must be furnished by the Applicant in the form of cash and in the amount as determined by the Market Operator, and shall forward to the Applicant copies of such other agreements, if any, as the Market Operator agrees to enter into, in final form for the Applicant to sign and return to the Market Operator.

2.3.3.3. The Market Operator may reject an Admission Application for one or more of the following reasons:

a) the Applicant does not possess the requisite Licence or regulatory authorization/permission/concurrence or other regulatory documents required under this Code;

b) the Applicant does not comply with any applicable rules and regulations;

c) the Applicant has not supplied the requisite information or has not got installed the requisite Commercial Metering System;

d) the Applicant does not agree for the provision of the Security Cover and Guarantee Amount in the form of cash and in the amount as determined by the Market Operator;

e) the Applicant previously defaulted on its obligations as a Market Participant and its enrolment was terminated and has not yet remedied the cause of such default.

2.3.4. FINAL STEPS TO BECOME A MARKET PARTICIPANT

2.3.4.1. Upon receipt of the final draft of the Market Participation Agreement and the determination of the Market Operator regarding amount of the Security Cover and Guarantee Amount pursuant to Clause 2.3.3.2, the Applicant shall:

a) execute the Market Participation Agreement, and return it to the Market Operator; and

b) if applicable, deposit with the Market Operator the required Security Cover and Guarantee Amount.

2.3.4.2. After receipt of the Market Participation Agreement, duly executed by an authorised official of the Applicant, and the required Security Cover and Guarantee Amount, the Market Operator shall enrol the Applicant as a Market Participant by giving it a unique identification number within five (5) Business Days of the receipt of the aforesaid documents and inform the Market Participant accordingly.

2.3.4.3. The Applicant shall be a Market Participant with effect from the date of enrolment and shall be provided access to the secured section of the MO Website. However, its right to carry out commercial transactions shall be subject to Clause 10.6.1.2.

2.3.4.4. The Market Operator shall:

a) provide to the newly enrolled Market Participant the names of all other Market Participants and their requisite details;

b) inform all other Market Participants the details of newly enrolled Market Participant.

2.3.5. RIGHTS FOR APPEAL AND RECONSIDERATION

2.3.5.1. Any person whose Admission Application has been rejected may challenge the decision of the Market Operator in accordance with the Dispute resolution procedure set out in Chapter 14.

2.4. MARKET PARTICIPANT ENROLMENT

2.4.1. MARKET PARTICIPANTS REGISTER

2.4.1.1. The Market Operator shall organise, maintain, and place on its website a register of Market Participants called the Market Participants Register. The Market Participants Register shall identify the status of each Market Participant, namely: active, suspended, terminated, withdrawn or notified for withdrawal.

2.4.1.2. Upon admission of a Market Participant in one or more Categories of Market Participants, the Market Operator shall record the relevant information in the Market Participants Register.

2.4.1.3. The Market Participants Register shall clearly indicate the Categories in which a Market Participant is enrolled.

2.4.1.4. The Market Operator shall update the Market Participants Register upon:

a) enrolment of a new Market Participant;

b) issuance of a Suspension Order;

c) termination or withdrawal;

d) receipt of new information as per Clause 2.4.2.1.

2.4.2. MARKET PARTICIPANT'S ONGOING REPORTING OBLIGATIONS

2.4.2.1. Each Market Participant shall have an ongoing obligation to inform the Market Operator of any material change related to its business and to the information included in its Admission Application, including any modification in the technical or operational characteristics of the equipment it owns and is connected to the Grid System.

2.4.2.2. If a Market Participant fails to comply with the requirements of Clause 2.4.2.1, which may have a materially adverse effect on the buying and selling obligations of other Market Participants, the Market Operator may suspend or terminate the Market Participant's rights in accordance with Chapter 16 of this Code.

2.5. WITHDRAWAL OR TERMINATION OF ENROLMENT OF A MARKET PARTICIPANT

2.5.1. WITHDRAWAL BY A MARKET PARTICIPANT

2.5.1.1. A Market Participant may withdraw as a Market Participant at any time subject to fulfilment of the following conditions:

a) by giving notice of not less than two (2) months in writing to the Market Operator;

b) the Market Operator shall examine the withdrawal notice and verify compliance of the Market Participant with the requirement of Clause 2.5.1.2 below and may accept or reject the notice;

c) upon acceptance of the notice, the Market Operator shall deregister all of its Bilateral Contracts with other Market Participants, as stipulated in Sub-Section 3.6.

2.5.1.2. The requirements to be fulfilled by the Market Participant prior to its withdrawal, pursuant to Clause 2.5.1.1 above are:

a) The Market Participant has obtained prior written consent of the Authority to its ceasing to be a Market Participant, where this consent is required by the existing policy, rules or regulations or the conditions of its License. Its withdrawal shall take effect only on such terms and conditions as the Authority may determine;

b) all amounts due and payable by the Market Participant under or pursuant to this Code have been paid in full prior to the Termination Date;

c) the Market Participant is not in breach of any legal, policy or regulatory requirement, including any required consent from the Authority, by ceasing to be a Market Participant; and

d) the Market Participant has remedied any breach which is capable of remedy prior to the withdrawal notice.

2.5.1.3. Notwithstanding compliance with Clause 2.5.1.2 above, the Market Participant shall remain liable for all obligations and liabilities which were incurred or arose due to actions of the Market Participant prior to the Termination Date regardless the date on which such claim relating thereto may be made. The Market Operator may withhold its Security Cover or Guarantee Amount in full or a portion thereof, if it considers that there are charges to be calculated in future for the upcoming yearly or monthly Settlement Statement which may be payable by the Market Participant.

2.5.1.4. The acceptance of the withdrawal notice by the Market Operator and subsequent deregistration of the Contracts shall result in the automatic termination of the Market Participation Agreement.

2.5.2. TERMINATION DECIDED BY THE MARKET OPERATOR

2.5.2.1. The Market Operator may decide to revoke the enrolment of a Market Participant in accordance with the provisions of Chapter 16.

2.6. <u>ENROLMENT OF SERVICE PROVIDERS</u>

2.6.1.1. Any person holding a Transmission License, Distribution License or registered by the Authority as Metering Service Provider, shall enrol as a Service Provider with the Market Operator, in accordance with the provisions of this Chapter.

2.6.1.2. If at any time, a Service Provider ceases to be eligible to be enrolled as a Service Provider in accordance with this Code, the Service Provider shall immediately inform the Market Operator and, as soon as practicable, the Market Operator shall inform the Authority.

2.7. <u>RIGHTS AND OBLIGATIONS OF THE SERVICE PROVIDERS</u>

2.7.1.1. A Service Provider shall have, *inter alia*, the following obligations relevant to this Code:

a) submit to the System Operator and the Market Operator, in a timely manner and to the best of its knowledge, the information stipulated in this Code or as may be required by the System Operator and the Market Operator in accordance with this Code, and inform, as soon as possible, any change in such information;

b) pay in time any Amounts Payable to the Market Operator;

c) if applicable, maintain a bank account for the administration of the market payment system;

d) abide fully with this Code as applicable.

2.7.1.2. . In the Market, each Service Provider shall have, *inter alia*, the following rights:

a) undertake the market related activities for which it has been enrolled by the Market Operator;

b) access to the reports and Non-Confidential Information on the website of the Market Operator, which are defined as non-confidential in this Code;

c) submission of complaints to the System Operator regarding a function assigned to it under this Code or to the Market Operator in accordance with the procedures provided in this Code.

2.8. PROCEDURE TO ENROL AS A SERVICE PROVIDER

2.8.1. APPLICATION TO ENROL AS SERVICE PROVIDER

2.8.1.1. The Market Operator shall develop a CCOP which shall include the following:

a) to describe in detail the requirements to enrol as a Service Provider and maintain such enrolment;

b) The requisite information and documents to be furnished by the Applicant for each type of service;

c) An Admission Application;

d) Detailed procedure for approval and rejection of the Admission Application; and

e) Procedure for modification of the information already submitted by a Service Provider.

2.8.1.2. The Market Operator shall make available on its website the following documents and information in the updated form:

a) the Admission Application form for enrolment of Service Providers;

b) the Commercial Code along with CCOPs;

c) draft Standard Service Provider Agreement; and

d) if applicable, the schedule of fees for processing an Admission Application.

2.8.1.3. Any person interested to become a Service Provider shall submit to the Market Operator:

a) a complete Admission Application;

b) the information required in the CCOP relevant to the admission process;

c) if applicable, a non-refundable application processing fee as determined by the Market Operator.

2.8.1.4. An Applicant who wants to be enrolled for more than one type of services shall submit separate application for each type of service.

2.8.2. APPLICATION PROCESS

2.8.2.1. The process defined under Sub-section 2.3.2 shall, *mutatis mutandis*, apply to enrol a person as a Service Provider.

2.8.3. PROCEDURE FOR APPROVAL / REJECTION OF AN ADMISSION APPLICATION

2.8.3.1. If the Applicant fulfils the requirement specified in this Code and the relevant CCOP, the Market Operator shall accept the Admission Application and provide the Applicant the standardized Service Provider Agreement for execution.

2.8.3.2. The Market Operator may reject an Admission Application for enrolment as a Service Provider for one or more of the following reasons:

a) the Applicant does not possess the requisite Licence or registration with the Authority;

b) the Applicant has not supplied the requisite information.

2.8.4. FINAL STEPS TO ENROL AS A SERVICE PROVIDER

2.8.4.1. Upon receipt of the Service Provider Agreement forwarded by the Market Operator pursuant to Clause 2.8.3.1, the Applicant shall execute the Service Provider Agreement, and return it to the Market Operator.

2.8.4.2. After receipt of the Service Provider Agreement, duly executed by an authorised official of the Applicant, the Market Operator shall enrol the Applicant as a Service Provider by giving it a unique identification number within five (5) Business Days of the receipt of the aforesaid documents and inform the Service Provider accordingly.

2.8.4.3. The Market Operator shall inform all Market Participants and Service Providers the details of newly enrolled Service Provider.

2.8.5. DISPUTE RESOLUTION

2.8.5.1. Any person whose Admission Application has been rejected may challenge the decision of the Market Operator in accordance with the Dispute resolution procedure set out in Chapter 14.

2.8.6. SERVICE PROVIDER REGISTER

2.8.6.1. The Market Operator shall organise, maintain, and place on its website a register of Service Providers called the Service Providers Register.

2.8.6.2. Upon enrolment as a Service Provider for one or more type of services, the Market Operator shall record the relevant information in the Service Providers Register.

2.8.6.3. The Service Providers Register shall clearly indicate the type of services for which a Service Provider is enrolled.

2.8.6.4. The Market Operator shall update the Service Providers Register upon:

a) enrolment of a new Service Provider;

b) termination or withdrawal of a Service Provider;

c) receipt of new information as per Clause 2.8.7.1.

2.8.7. SERVICE PROVIDER'S ONGOING REPORTING OBLIGATIONS

2.8.7.1. Each Service Provider shall have an ongoing obligation to inform the Market Operator of any material change related to its business and to the information included in its Admission Application, including any modification in the technical or operational characteristics of the equipment it owns and is connected to the Grid System.

2.8.7.2. If a Service Provider fails to comply with the requirements of Clause 2.8.7.1, which may have a materially adverse effect on the Market, the Market Operator may take an enforcement action in accordance with Chapter 16 of this Code.

2.9. WITHDRAWAL OR TERMINATION OF ENROLMENT AS A SERVICE PROVIDER

2.9.1. WITHDRAWAL BY A SERVICE PROVIDER

2.9.1.1. A Service Provider may withdraw its enrolment with the Market Operator at any time subject to fulfilment of the following conditions:

a) by giving notice of not less than two (2) months in writing to the Market Operator;

b) the Market Operator shall examine the withdrawal notice and verify compliance of the Service Provider with the requirement of Clause 2.9.1.2 below;

c) obtaining the prior written consent of the Authority.

2.9.1.2. The requirements to be fulfilled by the Service Provider prior to its withdrawal, pursuant to Clause 2.9.1.1 above are:

a) all amounts due and payable by the Service Provider under or pursuant to this Code have been paid in full prior to the withdrawal;

b) the Service Provider is not in breach of any legal, policy or regulatory requirement, including any required consent from the Authority, by ceasing to be a Service Provider; and

c) the Service Provider has remedied any breach which is capable of remedy prior to the withdrawal notice.

2.9.1.3. Notwithstanding compliance with Clause 2.9.1.2 above, the Service Provider shall remain liable for all obligations and liabilities which were incurred or arose prior to the withdrawal regardless the date on which such claim relating thereto may be made.

2.9.1.4. The acceptance of the withdrawal notice by the Market Operator shall result in the automatic termination of the Service Provider Agreement.

2.9.2. TERMINATION DECIDED BY THE MARKET OPERATOR

2.9.2.1. The Market Operator may revoke the enrolment of a Service Provider in accordance with the provisions of Chapter 16.

2.10. ENROLLED PERSONS

2.10.1. REQUIREMENT TO BECOME AN ENROLLED PERSON

2.10.1.1. The following persons shall enrol with the Market Operator to become Enrolled Persons:

a) A person who is not enrolled as Market Participant and intends to obtain Firm Capacity Certificates for a Generation Plant;

b) A person who is a BPC and is not registered as Market Participant and intends to sign a Standardized Load Following Contract with a Competitive Electric Power Supplier.

2.10.2. PROCEDURE TO BECOME AN ENROLLED PERSON

2.10.2.1. The process defined under Section 2.8 shall, *mutatis mutandis*, apply to become an Enrolled Person.

2.10.3. RIGHTS AND OBLIGATIONS OF ENROLLED PERSONS

2.10.3.1. An Enrolled Person shall have, *inter alia*, the following obligations:

a) comply with the provisions of this Code;

b) timely submit any information required by the Market Operator;

c) any other obligations as required under this Code.

2.10.3.2. Each Enrolled Person shall have, *inter alia*, the following rights:

a) obtain the Firm Capacity Certificate or be a party to a Standardized Load Following Contract, as the case may be;

b) become a Market Participant subject to fulfilling the eligibility requirements as provided in this Code;

c) access to the reports and Non-Confidential Information on the website of the Market Operator, which are defined as non-confidential in this Code;

d) submission of complaints to the Market Operator regarding its grievance.

2.11. ENROLMENT FEE

2.11.1. REQUIREMENT OF ENROLMENT FEE

2.11.1.1. The Market Operator may charge a fee to any person who submits an application to the Market Operator for enrolment as Market Participant or Service Provider or Enrolled Person.

2.11.1.2. The amount of fee as referred to in Clause 2.11.1.1 above shall be approved by the Board of Market Operator for each Category of Market Participants, Service Providers or Enrolled Persons and shall be published on MO Website.

Chapter 3. CONTRACTS AND CONTRACT REGISTRATION

3.1. CONTRACT MARKET

3.1.1. TRADING OF ENERGY AND CAPACITY

3.1.1.1. In the CTBCM, Energy and Capacity buying and selling among Market Participants shall be primarily carried out through Contracts which shall be registered with the Market Operator. The Contract Market shall include:

a) bilateral buying and selling among Market Participants; or

b) bilateral buying and selling between a Market Participant and entities located in foreign countries; or

c) bilateral buying and selling between a Market Participant and a person which operates under a special regime in areas where the applicability of the Act is not extended.

d) Bilateral buying and selling between a Market Participant and other persons which have been exempted from enrolment as Market Participants as per Clause 2.1.1.3 above.

3.1.2. MANDATORY CLAUSES

3.1.2.1. All Market Participants shall ensure that the Contracts are designed in such a way that all Energy and Capacity is bought or sold through these Contracts or through the Balancing Mechanism for Energy and Capacity provided in this Code.

3.1.2.2. All Contracts, to be registered with the Market Operator, must include a clause whereby both parties agree to abide by this Code, and the Act, rules, regulations, Grid Code and any other document as may be approved or issued by the Authority from time to time.

3.1.2.3. All Contracts, as referred to in Clause 3.1.2.2, where the seller is a Generator or a person representing Generators shall include conditions establishing that the seller in the Contract agrees to provide all Ancillary Services as stipulated in the Grid Code, if the contracted generation has the technical capability and equipment to do so, without any additional payment other than those explicitly provided in Chapter 6.

3.2. CONTRACT FORMATS

3.2.1. GENERAL REQUIREMENTS FOR CONTRACTS

3.2.1.1. A Contract in the CTBCM shall be bilaterally agreed between a seller and a buyer and it may include Energy, Capacity or both products simultaneously. The transactions for each of these two products shall be explicitly specified in the Contract for each Trading Period.

3.2.1.2. For the application of this Code:

a) the Energy Trading Period is defined as one hour.

b) the Capacity Trading Period is defined as one day, starting at 0:00 and ending at 23:59 of the same day.

3.2.1.3. The contracted Energy quantities as agreed in the registered Contracts, will be used for Settlement of the Imbalances of Energy.

3.2.1.4. The contracted Capacity quantities as agreed in the registered Contracts will be used for:

a) verifying compliance with the ex-ante Capacity Obligations of the Market Participants; and

b) calculating the Capacity Balances of the Market Participants in the Balancing Mechanism for Capacity and verification of ex-post Capacity Obligations.

3.2.1.5. Capacity transactions in a registered Contract may be agreed as following:

a) **Guaranteed Capacity:** Where the seller assumes complete responsibility for the Capacity Imbalances, which may arise in the Balancing Mechanism for Capacity, linked with the value of Capacity sold by the seller, as provided in Chapter 9;

b) **Non-guaranteed Capacity:** Where the buyer assumes complete responsibility for the Capacity Imbalances, which may arise in the Balancing Mechanism for Capacity, linked with the value of Capacity bought by the buyer, as provided in Chapter 9.

For the avoidance of doubt, Capacity transactions, either Guaranteed or Non-guaranteed shall be credited to the buyer for compliance with the ex-ante Capacity Obligations of the buyer, as specified in Chapter 10.

3.2.2. TYPES OF CONTRACTS

3.2.2.1. A Contract agreed between a seller and a buyer may be classified as under:

a) Standardized Contract

b) Customized Contract

3.2.2.2. A Standardized Contract is a Contract in which the amount of Energy and Capacity is bought and sold according to the pre-defined terms and conditions. These types of Contracts are further explained in Section 3.3.

3.2.2.3. In case a Standardized Contract has been executed, and the parties formally declare this during the Contract registration process, it will not be necessary to disclose the signed Bilateral Contract to the Market Operator, and it would be sufficient to provide information required in this Code to proceed with the registration of the Contract.

3.2.2.4. A Customized Contract is a Contract that may not be classified as a Standardized Contract. In case a Customized Contract has been executed, the Market Operator may require the parties to provide any information it deems necessary to ensure proper settlement of the contracted quantities in the Balancing Mechanism for Energy and Capacity. However, as specified below:

a) the Market Operator, if adequately justified, may review the original Contract signed between the parties only in order to assess the implication of certain clauses or provisions in the balancing mechanisms settlement process and Capacity Obligations;

b) the Market Operator shall not review the prices or other commercially sensitive information agreed between the parties to the extent that such information is not necessary to take a decision, provided that it will be decided by the Market Operator whether certain information, excluding the prices, is commercially sensitive or not subject to the Market Operator providing the justification in writing;

c) all the information received by the Market Operator, other than the information to be incorporated into the Contract Register shall be considered Confidential Information and shall be handled as per provisions of Chapter 17; and

d) In case of any dispute between the Market Operator and the Market Participant with regard to provision of information required in sub-clause (a) above, the dispute will be settled in accordance with the dispute resolution mechanism provided in this Code.

3.2.2.5. Following types of Contracts shall be considered Standardized Contracts:

a) Generation Following Supply Contract

b) Capacity and Associated Energy Supply Contract

c) Load Following Supply Contract

d) Financial Supply Contract with Fixed Quantities

3.3. CHARACTERISTICS OF STANDARDIZED CONTRACTS

3.3.1. GENERATION FOLLOWING SUPPLY CONTRACT

3.3.1.1. In a Standardized Generation Following Supply Contract, the seller may sell:

a) a defined percentage of the Capacity associated with the Physical Asset or assets; and

b) a defined percentage of the Energy injected into the Grid System.

3.3.1.2. This Contract shall have, *inter alia*, the following characteristics:

a) the seller either may be a Generator or an Electric Power Trader and the buyer either may be an Electric Power Supplier or an Electric Power Trader;

b) the Contract shall be associated with a Physical Asset or group of Physical Assets, clearly identified;

c) the amount of Energy bought and sold shall be a defined percentage of all the Energy injected into the Grid System by the associated Generation Plant at each Trading Period;

d) the amount of Capacity bought and sold shall be a defined percentage of the Firm Capacity Certificates issued by the Market Operator, associated with the Physical Asset;

e) the percentages used for the Capacity and the Energy may be different ranging from zero (0%) to one hundred (100%);

f) the Capacity bought and sold is Non-Guaranteed;

g) the revenues that a Generator may be eligible to receive for the provision of Ancillary Services and Transmission Must Run or Reliability Must Run shall be assigned to the buyer; and

h) the duration of the Contract shall be at least, two (2) years starting from the Effective Date of the Contract.

3.3.1.3. Following information shall be provided by the parties during the Contract registration process:

a) identification of the buyer and seller;

b) identification of the Physical Asset or assets and the corresponding Trading Points for the commercial transactions;

c) a defined percentage of the total Energy injected into the Grid System by the seller which shall be considered to calculate the contracted quantities;

d) number of Firm Capacity Certificates, associated with the Physical Asset involved in the Contract;

e) declaration of percentage of the total Capacity, backed by Firm Capacity Certificates, that the Generator is selling to the buyer; and

f) the Effective Date of the Contract and the duration of the Contract.

3.3.2. CAPACITY AND ASSOCIATED ENERGY SUPPLY CONTRACTS

3.3.2.1. The Standardized Capacity and Associated Energy Supply Contract is relatively similar to the Generation Following Supply Contracts, but it may also be used by BPCs. In a Standardized Capacity and Associated Energy Supply Contract, the seller may sell:

a) a defined percentage of the Capacity of the Physical Asset or assets; and

b) a defined percentage of the Energy injected into the Grid System.

3.3.2.2. This Contract shall have, *inter alia*, the following characteristics:

a) the seller either may be a Generator or an Electric Power Trader and the buyer either may be an Electric Power Supplier, an Electric Power Trader or a BPC;

b) the Contract shall be associated with a Physical Asset or group of Physical Assets, clearly identified;

c) the amount of Energy bought and sold shall be a defined percentage of all the Energy injected into the Grid System by the associated Generation Plant at each Trading Period;

d) the amount of Capacity bought and sold shall be a defined percentage of the Firm Capacity Certificates issued by the Market Operator, associated with the Physical Asset;

e) the percentages used for the Capacity and the Energy may be different ranging from zero (0%) to one hundred (100%);

f) the Capacity bought and sold can be Guaranteed or Non-Guaranteed, as agreed by the parties;

g) the revenues that the Generator may be eligible to receive for the provision of Ancillary Services and Transmission Must Run or Reliability Must Run shall be retained by the seller ; and

h) the duration of the Contract shall be, at least, two (2) years starting from the Effective Date of the Contract.

3.3.2.3. Following information shall be provided by the parties during the Contract registration process:

a) identification of the buyer and seller;

b) identification of the Physical Asset or assets and the corresponding Trading Points for the commercial transactions;

c) a defined percentage of the total Energy injected into the Grid System by the seller which shall be considered to calculate the contracted quantities;

d) number of Firm Capacity Certificates, associated with the Physical Asset involved in the commercial transaction;

e) declaration of percentage of the total Capacity, backed by Firm Capacity Certificates, that the Generator is selling to the buyer;

f) declaration whether the Capacity sold and bought shall be considered as Guaranteed or Non-Guaranteed; and

g) the Effective Date of the Contract and the duration of the Contract.

3.3.3. Load Following Supply Contracts

3.3.3.1. In a Standardized Load Following Supply Contract, the seller may sell all the Energy and Capacity which may be withdrawn by the buyer at a set of pre-defined Trading Points. The seller shall assume complete responsibility for the obligations of the buyer in the Balancing Mechanisms for Energy and Capacity, as well as for the Capacity Obligations imposed on the buyer.

3.3.3.2. This Contract shall have, *inter alia,* the following characteristics:

a) the seller may be a Generator, a Competitive Supplier or an Electric Power Trader;

b) the buyer may be an Electric Power Supplier, an Electric Power Trader or a BPC, and the Trading Points in such a Contract shall be demand points where the Energy always flow from the seller side to the buyer side;

c) The Contract shall be associated with a set of clearly identified Trading Points. This type of Contract shall not necessarily be associated with a Physical Asset or group of Physical Assets;

d) the amount of Energy bought and sold is the total Energy taken by the buyer, at each Energy Trading Period, at all the identified Trading Points;

e) the amount of Capacity bought and sold is the total Capacity used by the buyer, at any Capacity Trading Period, aggregated over all the identified Trading Points;

f) the Capacity bought and sold is Guaranteed Capacity;

g) the revenues that the seller may be eligible to receive for the provision of Ancillary Services and Transmission Must Run or Reliability Must Run, shall be retained by the seller; and

h) the duration of the Contract is, at least, two (2) years starting from the Effective Date of the Contract.

3.3.3.3. Following information shall be provided by the parties during the Contract registration process:

a) identification of the buyer and seller;

b) the effective date and duration of the Contract;

c) identification of the Trading Points involved in the transactions;

d) number of Firm Capacity Certificates that the seller may assign to the buyer to back the contracted quantities, which shall not be lower than the value indicated in 3.3.3.3.e). The status of these Firm Capacity Certificates will be changed to "Blocked" and they cannot be used by the seller to back any other Capacity transaction until such certificates are unblocked in accordance with the provisions of this Code.

e) maximum value of the demand aggregated over all the Trading Points of the buyer in the System Peak Hours of the last year. This value shall be:

e.1. certified by the Metering Service provider; or

e.2. certified by the Distribution Licensee, in case the Metering Service Provider does not have historical values at one or more Trading Points; or e.3. a formal declaration of the buyer, stating its best estimate of the maximum value of the aggregated demand, in case neither the Metering Service Provider nor the Distribution Licensee are able to certify such value or do not provide the certified values within a reasonable time.

3.3.4. FINANCIAL SUPPLY CONTRACT WITH FIXED QUANTITIES

3.3.4.1. In a Standardized Financial Supply Contract with Fixed Quantities, the seller may sell defined quantities of Energy and/or Capacity at each Energy and/or Capacity Trading Period.

3.3.4.2. This Contract shall have, *inter alia*, the following characteristics:

a) the seller and buyer shall be enrolled as Market Participants;

b) all or a specific group of Trading Points of each Market Participant are involved in the commercial transaction;

c) the amount of Energy bought and sold at each Energy Trading Period shall be a fixed value, expressed in MWh. The fixed values for the Energy bought and sold may be modified during the duration of the Contract, according to the procedure specified in Section 3.5.6;

d) for Settlement of Imbalances in the Balancing Mechanism for Energy, the Energy bought and sold at each Energy Trading Period shall be:

d.1. considered to be sold by the seller, regardless it has been produced by the seller or not;

d.2. considered to be bought by the buyer, regardless it has been used (consumed) by the buyer or not;

e) the amount of Capacity bought and sold at each Capacity Trading Period shall be a fixed value, expressed in MW, backed by Firm Capacity Certificates. The fixed values for the Capacity bought and sold shall not be modified during the duration of the Contract except where the number of Firm Capacity Certificates of the seller are reduced after review or renewal of the Firm Capacity Certificates;

f) the Capacity bought and sold may be "Guaranteed Capacity" or "Non-guaranteed Capacity", as may be agreed between the parties;

g) for settlement of Imbalances in the Balancing Mechanism for Capacity, the Capacity bought and sold at each Capacity Trading Period shall be:

g.1. Considered to be sold by the seller and procured by the buyer in full, regardless of the actual availability of the Physical Assets involved in the Firm Capacity Certification if the transaction has been informed as "Guaranteed Capacity"; or

g.2. Considered to be sold by the seller and procured by the buyer, conditional to the actual availability of the Physical Assets involved in the Firm Capacity Certification, if the transaction has been informed as "Non-guaranteed Capacity";

h) the revenues that the seller may be eligible to receive for the provision of Ancillary Services and Transmission Must Run or Reliability Must Run, shall be retained by the seller; and

i) the duration of the Contract shall be at least, two (2) years starting from the Effective Date of the Contract.

For the avoidance of doubt, in the case the seller is a Generator, the registration of a Financial Supply with Fixed Quantities Standardized Contract with the Market Operator does not grant any Self-dispatch prerogative to the involved Generator.

3.3.4.3. Following information shall be provided by the parties during the Contract registration process:

a) identification of the buyer and seller;

b) Effective Date of the Contract and total duration of the Contract

c) amount of the Energy sold and bought by the parties, at each Energy Trading Period, for the complete duration of the Contract;

d) amount of the Capacity sold and bought by the parties, at each Capacity Trading Period, for the complete duration of the Contract;

e) identification of the Firm Capacity Certificates that the seller sells to the buyer to back the Capacity transaction, at each Capacity Trading Period;

f) explicit indication that the bought and sold Capacity shall be considered Guaranteed or Non-Guaranteed; and

g) a declaration whether the amounts of Energy bought and sold, as per clause 3.3.4.3.c) shall be considered for the whole duration of the Contract or they can be periodically adjusted according to the provisions of Section 3.5.6.

3.4. CUSTOMIZED CONTRACTS

3.4.1.1. A Customized Contract may be bilaterally agreed between a buyer and a seller for buying and selling of Energy and/or Capacity as per terms and conditions agreed between the parties.

3.4.1.2. For registration of a Customized Contract with the Market Operator, the following requirements shall be fulfilled:

a) the duration of the Contract is, at least, two (2) years starting from the effective date of the Contract.

b) the Contract incorporates the mandatory clauses as provided in Sub-Section 3.1.2 or, alternatively, a signed declaration is provided by both parties to the Market Operator stating that such clauses have been incorporated into the Contract;

c) the Energy bought and sold between the parties is in accordance with the requirements of Sub-Section 3.4.2;

d) the Capacity bought and sold between the parties is in accordance with the requirements of Sub-Section 3.4.3; and

e) the parties shall provide all the information required by the Market Operator to ensure that the contracted quantities can be properly settled in both the Energy and Capacity Balancing Mechanisms.

3.4.2. CONTRACTS INVOLVING ENERGY TRANSACTIONS

3.4.2.1. The contracted quantities of Energy agreed between the Market Participants through a Customized Contract shall be clearly specified for each Energy Trading Period.

3.4.2.2. The contracted quantities of Energy shall be specified as:

a) a fixed quantity, expressed MWh, for each Energy Trading Period; or

b) a percentage of Energy, injected or withdrawn at a registered Trading Point (either purchased or sold), for each Energy Trading Period; or

c) any other formula that clearly specifies the calculation of the contracted quantities and the Market Operator is provided with, before the Settlement, all the necessary data for the calculation of the contracted quantities or where a Market Participant intends to register multiple Contracts linked to a single Metering Point, the priority among the Contracts shall be clearly specified at the time of registration of the Contracts.

3.4.2.3. The contracted quantities of Energy shall not be conditional upon any event or parameters which are not explicitly provided for in this Code.

3.4.2.4. For the avoidance of doubt, Energy transactions which involve a fixed quantity of Energy which should be produced by a pre-defined Physical Asset or group of Physical Assets (Self-dispatch), are not allowed in the CTBCM, unless explicitly permitted in this Code.

3.4.3. CONTRACTS INVOLVING CAPACITY TRANSACTIONS

3.4.3.1. The contracted quantities of Capacity agreed between the Market Participants through a Customized Contract shall be clearly specified for each Capacity Trading Period.

3.4.3.2. All Capacity transactions in the CTBCM shall be backed by Firm Capacity Certificates issued by the Market Operator.

3.4.3.3. The Capacity transactions shall be specified as:

a) a fixed quantity, expressed in MW for each Capacity Trading Period; or

b) a defined percentage of the number of Firm Capacity Certificates or Capacity associated with a clear identification of the Physical Assets involved or a formula to calculate such percentage/quantity.

3.4.3.4. The Firm Capacity Certificates used to back the Capacity transaction shall be either:

a) transferred from the seller to the buyer; or

b) changed their status to "Blocked";

depending on the type of Contract agreed in the transaction.

3.4.3.5. The contracted quantities of Capacity shall not be conditional upon any event or parameters which are not explicitly provided for in this Code.

3.4.4. INFORMATION TO BE PROVIDED FOR CUSTOMIZED CONTRACTS

3.4.4.1. Following information shall be provided by the parties during the registration process of a Customized Contract:

a) identification of the buyer and seller;

b) the effective date and total duration of the Contract;

c) identification of Trading Points;

d) amount of the Energy sold and bought by the parties, during each Energy Trading Period, for the complete duration of the Contract, or provide a formula along with relevant information that clearly specifies the calculation of the contracted quantities;

e) amount of the Capacity sold and bought by the parties, during each Capacity Trading Period, for the complete duration of the Contract, or provide a formula along with relevant information that clearly specifies the calculation of the contracted quantities;

f) identification of the Firm Capacity Certificates that the seller sells to the buyer to back the Capacity transaction, during each Capacity Trading Period;

g) explicit declaration that the bought and sold Capacity shall be considered Guaranteed or Non-Guaranteed;

h) a declaration whether the amounts of Energy bought and sold, as per clause 3.3.4.3.c) shall be considered for the whole duration of the Contract or these amounts may be periodically adjusted as per provisions of Sub-Section 3.5.6.

3.4.4.2. During the registration process, the Market Operator may require any other information it deems necessary, with adequate justification, in order to assess conformity of the Contract with the provisions of this Code. Such information may include copies of parts, sections or clauses of the signed Bilateral Contract, excluding price or other commercially sensitive information, provided however, that it will be decided solely by the Market Operator whether certain information is commercially sensitive or not.

3.4.4.3. In case of any dispute between the Market Operator and the Market Participant with regards to provision of information required in 3.4.4.2 above, the dispute will be settled in accordance with the dispute resolution mechanism provided in this Code.

3.5. CONTRACT REGISTRATION

3.5.1. THE CONTRACT REGISTER

3.5.1.1. The Market Operator shall organize and maintain a register of the Energy and Capacity sold and purchased in Contracts, along with the information submitted by the Market Participants, provided that the Contract Register shall not contain any price or commercially sensitive information of the Market Participants. The purpose of the Contract Register shall be:

a) determination of quantities purchased and sold in the Balancing Mechanisms for Energy and Capacity;

b) keeping record of contracted quantities of Energy and Capacity in order to perform the Settlement process;

c) verification of compliance with the Capacity Obligations.

3.5.1.2. The Contract Register shall record the following information for each Contract:

a) details of the contracting parties;

b) duration and effective date of the Contract;

c) type of Contract (Standardized or Customized);

d) for Standardized Contracts:

d.1. the type of Standardized Contract; and

d.2. the information required in Sub-Sections 3.3.1, 3.3.2, 3.3.3, or 3.3.4, as the case may be;

e) For Customized Contracts, the information required in Sub-Section 3.4.4.

3.5.1.3. The Market Operator shall update the Contract Register in case of:

a) revision of amount of the contracted Energy under Sub-Section 3.5.6;

b) modification of a registered Contract; or

c) termination of a registered Contract.

3.5.2. APPLICATION FOR CONTRACT REGISTRATION

3.5.2.1. Each Market Participant shall request the Market Operator for registration of each Contract it has signed for buying and selling of Energy and/or Capacity as per mechanism defined in this Code.

3.5.2.2. The Market Operator shall prepare and publish on its Website a form for Contract Registration specifying the requisite information for registration of a new Contract or modifications of a registered Contract, in accordance with this Code.

3.5.2.3. The Market Operator shall make a CCOP specifying the following for registration of a Contract in accordance with this Code :

a) the detailed information to be provided by the Market Participants for all types of Contracts;

b) the documents to be furnished by the Market Participants for all types of Contracts;

c) specific information and documents required for each type of Contract;

d) the Contract Registration application form;

e) the checks and verifications to be performed; and

f) the Contract registration, modification and de-registration procedure.

3.5.3. PROCESSING THE CONTRACT REGISTRATION APPLICATION

3.5.3.1. The parties to a Contract may submit a joint application for registration of a new Contract, or modification thereof, duly signed by the authorized representatives of both the parties.

3.5.3.2. Within three (3) Business Days of receipt of application for Contract Registration, the Market Operator shall provide acknowledgement thereof.

3.5.3.3. The Market Operator shall review the application for Contract registration and verify whether it is in accordance with this Code and the relevant CCOP, performing the checks and verifications it deems appropriate. The Market Operator may request the applicants for additional information during the verification process and the applicants shall be required to submit the information within the specified time.

3.5.3.4. Within fifteen (15) Business Days of receipt of an application and subject to provision of requisite additional information pursuant to Clause 3.5.3.3 above, the Market Operator shall inform the applicants, whether:

a) the application for Contract registration is not in accordance with any of the requirements of this Code as provided in Clause 3.5.3.6 below or the relevant CCOP and the Contract may not be registered; or

b) the application for Contract Registration complies with the requirements of this Code and the Contract may be registered subject to provision of the requisite Security Cover and Guarantee Amount according to the provisions of Chapter 13.

3.5.3.5. Where an applicant fails to provide additional information or the requisite Security Cover and Guarantee Amount within the specified time or a maximum of 3 months, the application shall automatically lapse, however, the applicants may reapply to the Market Operator after fulfilling all the requirements.

3.5.3.6. The Market Operator may reject an application for registration of a Contract, where:

a) any of the parties to the Contract is not a Market Participant, except explicitly exempted from enrolment as Market Participant as per Clause 2.1.1.3.

b) The application contains discrepancies or conflicting information, and the parties have failed to rectify such discrepancies as required by the Market Operator, pursuant to Clause 3.5.3.3;

c) the Contract is in conflict with another registered Contract by one or both of the parties;

d) the Contract is a Customized Contract and is not in accordance with the requirements set out in this Code;

e) the Contract deals with a Capacity transaction and the seller does not own the necessary Firm Capacity Certificates to support the transaction; or

f) the Contract does not pass one or more of the verifications and checks provided in the relevant CCOP.

3.5.4. CONTRACT REGISTRATION

3.5.4.1. After receipt of the required amount of the Security Cover and Guarantee Amount, the Market Operator shall:

a) register the Contract into the Contract Register, within two (2) Business Days;

b) inform both parties that the Contract has been registered, and the date thereof.

3.5.4.2. For settlement purposes, the Contract shall become effective:

a) at the date provided by the parties; or

b) At 0:00 a.m. of the day following the registration date of the Contract in the Contract Register,

whichever is later.

3.5.5. DISPUTE RESOLUTION

3.5.5.1. Any party of the Contract aggrieved by any decision of the Market Operator including a decision to reject the registration of its Contract pursuant to Clause 3.5.3.6, may have recourse to the Dispute resolution procedures set out in Chapter 14.

3.5.6. Modification of the Contract and the Contract Register

3.5.6.1. The Market Participants may modify a registered Contract without requiring de-registration of a Contract, however, such modification shall be limited only to the extent of contracted quantities of Energy or Capacity; or allocation of Transmission Must Run or Reliability Must Run or Ancillary Service revenues; or adding or deleting Trading Points. It is clarified that the contract type shall remain the same.

3.5.6.2. In case of a modification of a registered Contract as provided above, the parties shall inform the Market Operator on a form prepared for this purpose within five business days of modification and not later than five Business Days prior to the date when the Market Operator shall initiate the calculation for the monthly or yearly Settlement process. For the avoidance of doubt, the Contract shall be enforceable for the purposes of settlement by the Market Operator from the date of registration of modification with the Market Operator or any other later date as agreed in the Contract modification.

3.5.6.3. Within two (2) Business Days of receipt of a request for modification of a registered Contract, the Market Operator shall send a written acknowledgement thereof.

3.5.6.4. The Market Operator shall review the modification and verify whether it conforms with the provisions of this Code and the relevant CCOP.

3.5.6.5. The Market Operator may reject a request for modification, where:

a) if applicable, any of the involved Market Participant or other party to the Contract does not own the Firm Capacity Certificates to support the required modification;

b) allowing the modification, may result in non-compliance with the Capacity Obligations of one or both Market Participants;

c) the registered Security Cover and Guarantee Amount of one or both involved Market Participants is not sufficient to guarantee the eventual transactions in the BME or BMC, as applicable;

d) the requested modification in the registered Contract conflicts with other Contracts, already registered, by one or both of the parties.

3.5.6.6. In case the Market Operators accepts the modification in the registered Contract, it shall:

a) record the modification in the Contract Register and if applicable, also adjust the Firm Capacity Register accordingly;

b) immediately inform the parties about the modification in the Contract Register.

3.5.6.7. For the Settlement purposes, the modification in the registered Contract shall become effective:

a) at the date provided by the parties; or

b) At 0:00 a.m. of the day following the registration of the modification in the Contract Register pursuant to Clause 3.5.6.6;

whichever is later.

3.6. CONTRACTS DEREGISTRATION OR SUSPENSION

3.6.1. REASONS FOR DEREGISTRATION AND SUSPENSION

3.6.1.1. The Market Operator may deregister a Bilateral Contract from the Contract Register in the following cases:

a) a Bilateral Contract has reached Contract Termination Date; or

b) both parties agree on earlier termination of the Contract for a justifiable reason with prior approval of the Market Operator:

Provided that if the Market Operator does not approve termination of the Contract, the obligations of parties as registered by the Market Operator shall remain intact notwithstanding any termination of Contract by the parties; or

c) one of the parties for which it is mandatory to be a Market Participant ceases to be a Market Participant, as per Termination Order issued by the Market Operator, according to the provisions of Sub-Section 16.2.3.

3.6.1.2. The Market Operator may suspend the Bilateral Contract if one of the parties for which it is mandatory to be a Market Participant is suspended as Market Participant, according to the provisions of Sub-Section 16.2.2, in cases the remedial action taken by the Market Operator is to suspend a Contract.

3.6.2. DEREGISTRATION DUE TO CONTRACT TERMINATION

3.6.2.1. Where a Contract is about to reach its agreed Termination Date, the Market Operator shall require the parties to take necessary actions as detailed below as well as inform them about the actions the Market Operator is going to take. The parties shall be informed:

a) at least six (6) months prior to the Contract Termination Date, in case one of the parties is a BPC; or

b) at least three (3) months prior to the Contract Termination Date in all other cases.

3.6.2.2. Where one of the parties to the registered Contract is a BPC, regardless such BPC is a Market Participants or not, the Market Operator shall require such BPC to inform the Market Operator, at least 60 days prior to the Contract Termination Date, about its intention to:

a) Continue or renew the existing registered Contract, if it is decided by the BPC to continue the existing registered Contract, it shall submit jointly with the selling party an application for extension in the term of the Contract and to make requisite changes in the Contract Register at least five (5) Business Days prior to the Contract Termination Date by following the procedures set out in Sub-Section 3.5.6;

b) Sign a new Bilateral Contract with another Market Participant, in which case the BPC is required to inform the Market Operator by submitting an application jointly with the selling party for Contract Registration at least fifteen (15) Business days prior to the Contract Termination Date by following the procedure set out in Section 3.5;

c) Not to sign a new Bilateral Contract and start receiving its supply from the Supplier of Last Resort from the Contract Termination Date, in which case the BPC is required to inform the Market Operator that it will continue to purchase electric power from the concerned Supplier of Last Resort.

3.6.2.3. In case information as referred to in 3.6.2.2 above is not received from the BPC sixty days prior to expiry of its Bilateral Contract, the MO shall issue a notice to the BPC and the Supplier of Last Resort within a period of seven days after the date of sixtieth day prior to expiry of its Bilateral Contract, informing them that the BPC must convey its option to the MO with a copy to the concerned Supplier of Last Resort as required above within a period of fifteen days. In the event the BPC does not convey its option, it shall be considered that BPC is interested in becoming a consumer of the Supplier of Last Resort and accordingly the Supplier of Last Resort shall sign supply contract with the BPC, subject of fulfilment of requirements of consumer eligibility criteria regulations, and thereafter shall be responsible to recover any costs and tariff associated with supply of electric power to such BPC after the expiry of the Bilateral Contract.

3.6.3. DEREGISTRATION DUE TO EARLY CONTRACT TERMINATION

3.6.3.1. Where both parties have mutually agreed to terminate a Contract at an earlier date than the date communicated to the Market Operator during the registration of the Contract (Early Contract Termination), they shall inform the Market Operator accordingly, at least 20 Business Days prior to the agreed termination date, requesting deregistration of the Contract.

3.6.3.2. The Market Operator shall prepare and publish on its website a form for the purposes of deregistration of a Contract due to Early Contract Termination specifying the relevant information to be provided by the parties. The application for Contract deregistration shall be signed by both the parties to the Contract.

3.6.3.3. Within three (3) Business Days of receipt of an application, the Market Operator shall acknowledge the receipt thereof and, in case one of the parties is a BPC, the Market Operator shall require the BPC to register a new Contract, failing which the BPC shall be transferred to the Supplier of Last Resort as per Clause 3.6.5.1.

3.6.3.4. The Market Operator shall assess whether the application for deregistration of the Contract is in accordance with this Code and the relevant CCOP including the consequences set out in Sub-Section 3.6.5.

3.6.3.5. Within ten (10) Business Days of receipt of the application, the Market Operator shall inform the parties whether:

a) the application is in accordance with the provisions of this Code and the relevant CCOP and the Contract may be deregistered at the agreed date; or

b) the application is in accordance with the provisions of this Code and the relevant CCOP and the Contract may be deregistered subject to fulfilment of certain additional requirements by one or both of the parties as per Sub-Section 3.6.5; or

c) the application is not in accordance with provisions of this Code and the relevant CCOP, therefore, the Contract may not be deregistered accompanied with reasons thereof.

3.6.3.6. The Market Operator may reject an application for deregistration, where:

a) the application was submitted, without the consent of one of the parties;

b) the application contains discrepancies or conflicting information;

c) the Contract requested to be deregistered conflicts with other Contracts, already registered, by one or both of the parties;

d) the request does not pass one or more of the verifications as provided in the relevant CCOP.

3.6.4. DEREGISTRATION OR SUSPENSION DUE TO MARKET PARTICIPANT TERMINATION OR SUSPENSION

3.6.4.1. Where the Market Operator decides to suspend a Market Participant after following the procedure set out in Sub-Section 16.2.2 and issues a Suspension Order, the Market Operator may also suspend or deregister the relevant registered Contracts for such period as specified in the Suspension Order.

3.6.4.2. Where the Market Operator decides to terminate a Market Participant after following the procedure set out in Sub-Section 16.2.3, and issues a Termination Order, all the registered Contracts of such Market Participant shall be deregistered with effect from the date of the Termination Order.

3.6.4.3. If applicable, within the next three (3) Business Days after deregistration or suspension of the Contracts referred to in Clauses 3.6.4.1or 3.6.4.1, the Market Operator may inform one or more parties to the relevant Contracts about their obligations which they are required to fulfil as a result of deregistration or suspension of the Contracts and the timeframe thereof.

3.6.5. ACTIONS TAKEN AFTER CONTRACT DEREGISTRATION OR SUSPENSION

3.6.5.1. Where supply of electric power to a BPC is stopped, either partially or fully, due to deregistration or suspension of a Contract, excluding the cases as given in Sub-Sections 3.6.2 and 3.6.3 above, the Market Operator shall:

a) for all BPCs which are not enrolled as Market Participants:

a.1. inform the BPC to arrange its supply of electric power from another Competitive Supplier within (10) days and the Energy withdrawn during the interim period shall be considered to be supplied by the Supplier of Last Resort;

a.2. inform the Supplier of Last Resort accordingly; and

a.3. in case of suspension of a Contract, then upon withdrawal of the Suspension Order, transfer the supply of the BPC to the respective Competitive Supplier on the date of lifting of the Suspension Order.

b) for all BPCs which are Market Participants:

b.1. inform the BPC and require it to register new Contracts for purchase of electric power in order to comply with its Capacity Obligations within a specified timeframe;

b.2. inform the BPC that the Energy withdrawn during the interim period will be settled in the Balancing Mechanism for Energy and it has to provide the required amount of Security Cover and Guarantee Amount within a specified timeframe.

3.6.5.2. Failure of a BPC to register a new Contract or to provide the requisite Security Cover and Guarantee Amount, pursuant to Clause 3.6.5.1.b), shall constitute an Event of Default and shall be dealt with under Sub-Section 16.2.1.

3.6.5.3. The BPC shall be liable to pay all applicable charges for the supply of electric power by the Supplier of Last Resort under Clause 3.6.5.1, with effect from the date of deregistration or suspension of the Contract.

3.6.5.4. After deregistration of a Contract, the Market Operator shall update the Firm Capacity Register accordingly.

3.6.5.5. Immediately after the Firm Capacity Register update, the Market Operator shall verify compliance with the Capacity Obligations by all relevant Market Participants. In case a Market Participant, due to the re-assignation of the Firm Capacity Certificates, is not complying with its Capacity Obligations, the Market Operator shall require such Market Participants to resolve the non-compliance situation by contracting additional Capacity or installing additional Generation, within a specified timeframe. The Market Operator may not register any new Contract, other than Contracts for purchase of Capacity of the relevant Market Participant or BPC, till the time non-compliance situation is resolved.

3.6.5.6. Prior to deregistration of a Contract, at the time of evaluation of the consequences of such deregistration, the Market Operator shall recalculate the amount of Security Cover and Guarantee Amount which shall be provided by any of the parties to the Contract or other Market Participants affected by such deregistration. In case, the recalculated amount is higher than the amount registered in the Security Cover Register or the Settlement Guarantee Cover, the Market Operator shall require the relevant Market Participants to increase the amount of Security Cover and Guarantee Amount within a specified time pursuant to the provisions of Chapter 13. The Market Operator may delay the deregistration of a Contract until the recalculated Security Cover and Guarantee Amount is actually received.

3.6.5.7. Regardless of deregistration of a Contract, the parties shall remain liable for any outstanding obligations which accrued prior to such deregistration.

3.7. COMMERCIAL ALLOCATION OF LEGACY CONTRACTS-CPPA-G

3.7.1. COMMERCIAL ALLOCATION OF LEGACY CONTRACTS-CPPA-G

3.7.1.1. All the rights and obligations arising from the Legacy Contracts-CPPA-G, including the payments to or by the Generators, shall be commercially allocated as per the Allocation Factors set out in Clause 18.2.4.1.

3.7.1.2. The Allocation Factors shall be revised as per the National Electricity Plan and the same shall be used by the Market Operator for Settlement purposes and verification of compliance with Capacity Obligations. Till the time the National Electricity Plan is approved by the Federal Government, the procedure given in Sub-Section 18.2.5 shall apply.

3.7.2. REGISTRATION OF COMMERCIALLY ALLOCATED LEGACY CONTRACTS-CPPA-G

3.7.2.1. Before CMOD, the Market Operator shall register all Legacy Contracts-CPPA-G as per procedure given in Sub-Section 18.2.10.

3.7.3. REGISTRATION OF LEGACY CONTRACTS-KE

3.7.3.1. KE shall register with the Market Operator all the Legacy Contracts-KE before its integration into the CTBCM.

3.7.4. REGISTRATION OF LEGACY CONTRACTS-DISCOS

3.7.4.1. Each EX-WAPDA DISCO shall register all its Legacy Contracts-DISCOs before CMOD.

3.7.5. OTHER EXISTING CONTRACTS AT CMOD

3.7.5.1. The bilateral contracts, other than Legacy Contracts-CPPA-G, Legacy Contract-DISCOs and Legacy Contracts-KE, which were executed by the Market Participants before CMOD shall be registered with the Market Operator according to the provisions of Section 3.5 within one (1) year after the CMOD.

3.7.1. MERCHANT GENERATION

3.7.1.1. A Generator or a person representing a Generator may sell all of its Energy and Capacity through the Balancing Mechanisms for Energy and Capacity without registering any Bilateral Contract, subject to fulfilment of the following conditions:

a) The Generation Plant is capable to provide all of the Ancillary Services as mentioned in Clause 6.3.1.2 below except Black Start Capability provided that this condition will be reviewed within 2 years of the CMOD;

b) The Generator or the person representing the Generator is enrolled with the Market Operator as per Sub-Section **Error! Reference source not found.** above and has executed a Market Participation Agreement with the Market Operator.

Chapter 4. COMMERCIAL METERING SYSTEM

4.1. COMMERCIAL METERING REQUIREMENTS

4.1.1. GENERAL REQUIREMENTS

4.1.1.1. All Metering Points shall be equipped with a Commercial Metering System which complies with the provisions of this Code, the Grid or Distribution Code, as applicable.

4.1.1.2. Metering Points shall, *inter alia*, include interface between:

a) a Market Participant and a Transmission Licensee;

b) a Market Participant and a Distribution Licensee;

c) two different Market Participants;

d) a Transmission Licensee and a Distribution Licensee;

e) two different Transmission Licensees;

f) two different Distribution Licensees;

g) a Transmission Licensee or Distribution Licensee, and authorized entities from other countries, involved in international power trade;

h) a Transmission Licensee or Distribution Licensee, and companies or entities located in territories where the applicability of the Act is not extended;

i) a Distribution Licensee and Distribution Network Connected Generation; and

j) a Generator and the Transmission or Distribution Network where the Generator is selling electric power through a Legacy Contract-DISCOs, or Legacy Contract-KE or is owned by a Market Participant, who also owns the Transmission or Distribution Network, and the Energy or Capacity needs to be measured at such point for proper implementation of this Code.

4.1.2. RESPONSIBILITIES OF METERING SERVICE PROVIDERS

4.1.2.1. The responsibility for performing the meter reading at each Metering Point, performing the validity checks and transferring the information thereof to the Market Operator shall be assigned to the Metering Service Providers.

4.1.2.2. Each Metering Point shall be assigned to only one Metering Service Provider.

4.1.2.3. Every Metring Service Providers shall be enrolled with the Market Operator as a Service Provider.

4.1.2.4. A Metering Service Provider authorised/permitted or registered by the Authority, in addition to its responsibilities assigned under the Grid Code and the Distribution Code, shall:

a) install Secured Metering System at all Metering Points assigned to it;

b) create and maintain a central register and ensure proper functioning of all the Metering Points for which it is responsible;

c) ensure timely execution of verification, calibration, and technical inspection of the Commercial Metering System;

d) collect metering results from all the meters for which it is responsible.

e) perform the central aggregation of metering data and determine the accuracy thereof;

f) develop procedures for restoration, validation or replacement of the metering data;

g) set up communication channels for providing remote reading of the metering data;

h) submit the aggregated and validated metering data to the Market Operator in accordance with this Code;

i) create, maintain and ensure proper functioning of the electronic database of the metering data;

j) ensure the storage and archiving of the metering data and the data regarding technical conditions of the Commercial Metering System, in appropriate electronic databases.

4.1.3. REGISTRATION OF METERING SERVICE PROVIDERS WITH THE AUTHORITY

4.1.3.1. If required under the provisions of the Act and applicable rules and regulations, each Metering Service Provider shall be registered with the Authority. However, the existing Transmission Licensees shall not require additional registration if they have already been granted this function under their Transmission License.

4.2. METER READING AND DATA COLLECTION

4.2.1. GENERAL

4.2.1.1. Capacity taken from the Grid and Energy values used for the Settlement of the Market shall be measured through the Commercial Metering System, operated by the Metering Service Provider.

4.2.1.2. Collection of metering data from the Metering Points shall be carried out:

a) on daily basis, through the Secured Metering System (SMS);

b) in case of failure of the Secured Metering System, on a weekly basis, on the first Business Day of each week for values of the previous week, as provided under Sub-Section 18.2.2.

4.2.1.3. NTDC, appointed as MSP under Clause 18.2.1.1, shall develop and submit to the CCRP for approval, a CCOP for meter reading and data collection, in accordance with the Grid Code and this Code. The CCOP may include:

a) the details of the metering system;

b) details of communication channels between the meters and the database of the MSP and the transfer of such data to the Market Operator;

c) procedure for addition, deletion and updating of the Metering Points;

d) metering data collection, intervals, and processing;

e) collecting various labels attached to the data being collected and marking it as per the labels;

f) procedure for verification of the collected information;

g) detailed actions in case of invalidation of data, substitutions and estimations;

h) determination of best value for metering; and

i) transferring of data to the Market Operator.

4.2.1.4. The CCOP made by NTDC in accordance with Clause 4.2.1.3 above shall be applicable on all Metering Service Providers.

4.2.1.5. The Metering Service Provider shall submit a certificate to the Market Operator to the effect that the Commercial Metering System installed at the Metering Points complies with the requirements of this Code and the Grid Code. The Metering Service Provider shall organize and keep complete and accurate record containing all the information regarding the installation, commissioning and testing of the metering systems.

4.2.2. READING AND COLLECTION OF DATA THROUGH THE SECURED METERING SYSTEM

4.2.2.1. The Metering Service Provider shall implement a Secured Metering System, to collect and process all the commercial metering data from the relevant Metering Points, and electronically transfer the metring information to the Market Operator.

4.2.2.2. The Metering Service Provider shall perform Automatic Meter Reading of the values registered at all the Metering Points integrated into its Secured Metering System, every day, between 00:00:00 and 23:59:59 on the following day (D+1), or any other shorter period that may be provided in the CCOP.

4.2.2.3. The Secured Metering System shall collect information from all Meters located at a Metering Point, including the Main Meter and, if applicable, the Back-up Meter, according to the provisions of the Grid Code.

4.2.2.4. The information collected by the Secure Metering System shall include, *inter alia*, the following:

a) half-hourly values of active Energy and, if required, the reactive Energy, along with time stamps;

b) accumulated values of active Energy and, if required, the reactive Energy, for the previous day;

c) Maximum Demand Indicator (MDI) values for the Energy Settlement Period;

d) alarms and event logs generated by the Meters;

e) accuracy and other qualificators of the values recorded if the Meter generate such kind of information;

f) necessary time and date stamps.

4.2.2.5. After analysing and verification of the completeness and reliability of the values obtained, the Metering Service Provider shall determine accuracy and completeness of such values and shall mark these values either as "complete and accurate", "incomplete but accurate", "inaccurate" or "no data" according to the procedure set out in the relevant CCOP.

4.2.3. ACTIONS IN CASE OF FAILURE TO OBTAIN DATA

4.2.3.1. In case of failure to obtain the complete metering data from a Metering Point, the Metering Service Provider must promptly take all necessary steps to obtain such data, in particular, identifying and removing the causes of failure to obtain data and get all the requisite information.

4.2.3.2. In case of failure of the data collection and transmission equipment or the communication channels, the Metering Service Provider shall perform Electronic Local Meter Reading or Manual Local Meter Reading to obtain the values from the Metering Point as per provisions of Sub-Section 18.2.2 and the information obtained shall be marked as "complete and accurate" or "incomplete but accurate", as the case may be.

4.2.3.3. In case of failure of the Main Meter or the Back-Up Meter, the Metering Service Provider shall retrieve all the data from any other functional meter located at the Metering Point and mark it accordingly. The information obtained from the failed meter shall be marked as "no data".

4.3. METER READING VERIFICATIONS

4.3.1. VERIFICATIONS PERFORMED BY THE METERING SERVICE PROVIDER

4.3.1.1. The Metering Service Provider shall be responsible for checking the accuracy of the values obtained and shall process and validate such values, in order to:

a) refer the values obtained from the Meter to the Metering Point by making necessary adjustments, where the Commercial Metering System is installed at a location different than the Metering Point;

b) perform validity checks to determine the accuracy of the values obtained from the Meters. The Metering Service Provider shall perform the validation of metering data through a series of Validation Checks which are designed to determine the coherence and plausibility of each metered value or group of metered values regardless of the way such values are obtained (Automatic Meter Reading, Electronic Local Meter Reading or Manual Local Meter Reading).

4.3.1.2. After the verification and validation of the metering data, the Metering Service Provider shall classify each value as follows:

a) Valid: It is the value, or group of values, which pass all the Validation Checks. A Valid metered value may eventually become Invalid as a result of the analysis and evaluation of an incident, having additional information about the Metering Point or due to verifications or validations performed, at a later date;

b) Invalid: It is a value, or group of values, which does not pass one or more of the Validation Checks. An Invalid metered value or group of metered values may eventually become Valid as a result of further analysis performed by the Metering Service Provider.

4.3.1.3. The CCOP prepared under Clause 4.2.1.3 above shall also include:

a) formulas for performing the necessary calculations to refer the values to the Metering Point pursuant to Clause 4.3.1.1.a);

b) the minimum set of Validation Checks that shall be performed to determine the accuracy of the metered data;

c) the verification and tests to classify a metered value as Valid or Invalid pursuant to Clause 4.3.1.2.

4.3.2. ACTIONS TO BE TAKEN AFTER INVALIDATION OF DATA

4.3.2.1. When any metered value or group of metered values is classified as "Invalid", the Metering Service Provider shall obtain new values from the Metering Point including, if required, performing Local Meter Reading.

4.3.2.2. Where the new values obtained confirms the inadequacy of the data originally obtained or the new data still does not pass any of the Validation Checks, the Metering Service Provider shall open a Metering Incident Report and it shall proceed to test the Commercial Metering System of the relevant Metering Point.

4.3.2.3. If a metering problem or a failure is identified in a Main Meter during the validation process, the MSP shall forward to the Market Operator the following values for the settlement purposes:

a) if the Metering Point has a Back-up Meter, the data obtained from the Back-up Meter and duly validated;

b) if the Metering Point does not have a Back-up Meter, the Energy estimated by the System Operator based on the records stored in the SCADA system and the Metering Service Provider shall request the System Operator to provide the necessary information; or

c) if the Metering Point does not have back-up meter and no information is available with the System Operator, an estimation of the required quantities by the Metering Service Provider, taking due consideration of any additional metering information that may be available.

4.3.2.4. The Metering Service Provider may substitute the metering data with estimated values, in the following cases:

a) when a metered value, or group of metered values, have been marked as "Invalid", and it is not possible to obtain metered values which pass all the Validation Checks before the issuance date of the Preliminary Settlement Statement (temporary substitution);

b) when a metered value, or group of metered values, have been labelled as "Invalid" and it is not possible, to obtain metered values which pass all the Validation Checks before the issuance date of the Final Settlement Statement (final substitution);

c) when the resolution of a Metering Incident Report indicates a fault in the equipment of the Commercial Metering System, and it is not possible to retrieve accurate data unless the faulty equipment is replaced or repaired; and

d) when it is impossible to obtain data from the Commercial Metering System.

4.3.3. DATA PROVISION TO THE MARKET OPERATOR

4.3.3.1. Every day, the Metering Service Provider shall provide to the Market Operator the validated data for each hour of the previous day. In case there is some invalid data obtained from the Commercial Metering System or no data is obtained, the Metering Service provide shall provide to the Market Operator the valid data as soon as it is available.

4.3.3.2. Within three Business Days after completion of the month, the Metering Service Provider shall provide, for each hour of the previous month, complete and validated data either obtained through the Secured Metering System, Local Meter Reading or substituted values as per provisions of this Code.

4.3.4. DATA VERIFICATION BY THE MARKET OPERATOR

4.3.4.1. The Market Operator may perform additional validation or plausibility checks on the metering information provided by the Metering Service Provider.

4.3.4.2. The Market Operator shall include in the Settlement Statements information regarding any issues, errors or failures identified during the verification and validation process and the substituted values provided by the Metering Service Provider which were used to calculate the Energy for the Settlement Statement.

4.3.4.3. The Market Operator shall require the Metering Service Provider to take all necessary measures to rectify the causes which led to the substitution of the metered data.

4.4. <u>STORAGE AND CUSTODY OF COMMERCIAL METERING DATA</u>

4.4.1.1. The Metering Service Provider shall store commercial metering data in a secured manner for at least 5 years or any other longer period required to resolve any disputes among the Market Participants.

4.4.1.2. While storing the commercial metering data, the Metering Service Provider shall consider the following aspects:

a) Completeness of the stored data: The stored metering data shall contain all important information which may be required to restore the primary metering data.

b) Protection of data: The stored metering data shall be protected against accidental, intentional or unintentional changes.

c) Confidentiality of keys: Digital signature keys shall be used, kept secret and secured against any malware attacks or gaining unauthorized access.

d) Capacity of the storage database: Enough storage capacity shall be maintained for the metering data.

4.5. <u>COMMERCIAL METERING REPORT</u>

4.5.1.1. Every year, a Metering Service Provider shall prepare, and submit to the Market Operator, a Commercial Metering Report.

4.5.1.2. All relevant Market Participants and Service Providers shall assist the Metering Service Provider in the preparation of the Commercial Metering Report by providing accurate information in a timely manner in relation to the relevant Metering Points.

4.5.1.3. The Commercial Metering Report shall, *inter alia*, include:

a) list of all Metering Points which are not equipped with the requisite Commercial Metering System according to the provisions of this Code, the Grid Code or the Distribution Code, along with plans or measures to rectify this situation;

b) problems identified in the implementation of certain metering related provisions of this Code, the Grid Code or the Distribution Code;

c) conflicts among the Market Operator, the Metering Service Provider or Market Participants related to interpretation of provisions of this Code, the Grid Code or the Distribution Code, and the relevant CCOP;

d) compilation of all proposals which were submitted for amendment in this Code, the Grid Code or the Distribution Code regarding metering;

e) any other relevant matter to identify any problems in the performance, feasibility, efficiency and design of the Commercial Metering System.

Chapter 5. BALANCING MECHANISM FOR ENERGY

5.1. Balancing Mechanism for Energy

5.1.1. Purpose

5.1.1.1. The purpose of the Balancing Mechanism for Energy shall be to determine, for each Market Participant, the Imbalance of Energy calculated as the difference between the Energy actually injected into or withdrawn from the Grid System at the relevant Trading Points duly adjusted for the losses in the network and the contracted quantities registered in the Contract Register of the Market Operator.

5.1.2. Balancing Period and Settlement Period

5.1.2.1. The Market Operator shall calculate the Imbalance of Energy on hourly basis (the Energy Balancing Period) and the results thereof shall be consolidated on monthly basis for settlement purposes (the Settlement Period).

5.1.3. Required Information

5.1.3.1. Every month, the Market Operator shall use the following information for the administration of the Balancing Mechanism for Energy:

a) information provided by the Metering Service Provider for all Metering Points;

b) information related to contracted quantities of each Market Participant from the Contracts Register; and

c) System Marginal Prices provided by the System Operator for each hour of the month.

5.1.3.2. The Market Operator shall collect, properly organize, maintain, and keep custody of all the information used for the administration of the Balancing Mechanism for Energy, which shall be kept for at least five (5) years or any other longer period as may be required in the relevant rules and regulations.

5.2. Calculation of total generation and Back-feed Energy of the Generation Plants

5.2.1. Calculation of Generation by each Generation Unit

5.2.1.1. The Market Operator shall calculate the Energy injected into the Grid System in each hour by each Generation Unit as following:

a) In case there is dedicated Meter installed on a Generation Unit, the value recorded by the Meters, as provided by the Metering Service Provider, shall be considered:

$$GenU_{i,p,h}[MWh] = E_{MP_{i,p,h}}$$

Where:

- $GenU_{i,p,h}$is the quantum of Energy injected (Generation) to the Transmission or Distribution Network by Generation Uni "*i*" belonging to Generation Plant "p" in the hour "*h*", expressed in MWh;

- $E_{Mpi,p,h}$ is the value of Energy injected into the Transmission or Distribution Network, as provided by the Metering Service Provider according to the provisions of Chapter 4, at the Metering Point *i*, corresponding to the Generation Unit "i" belonging to Generation Plant "p" in the hour "*h*".

b) In case, there are no dedicated Meters installed on each Generation Unit of a Generation Plant and there are some Meters installed at the incoming/outgoing lines that measure the combined output of more than one Generation Units of the Generation Plant and the Meters also record the incoming and outgoing Energy flowing through the lines, then in such case the calculations shall be performed as following:

b.1. Calculate the net Energy injected into the Transmission or Distribution Network by subtracting the Energy recorded as withdrawn from the Transmission or Distribution network from the Energy recorded as injected into the Transmission or Distribution Network:

$$NetEnergy_{p,h}[MWh] = \sum_{\forall\, i \in Gen_p} E_{MP\,i,p,h}$$

Where:

- $NetEnergy_{p,h}$ is the quantum of Energy injected/withdrawn from the Transmission or Distribution Network by Generation Plant "*p*" in the hour "*h*", expressed in MWh;
- $E_{Mpi,p,h}$ is the value of Energy, as provided by the Metering Service Provider according to the provisions of Chapter 4, at the Metering Point "*i*", corresponding to the Generation Plant "p" in the hour "h";
- $\forall\ i \in Gen_p$ means all those Metering Points where Meters are installed at the incoming/outgoing lines of the Generation Plant "p".

Sign convention: For the application of the formula above, the Energy recorded at each Metering Point at each particular hour shall be considered positive if it is injected into the Transmission or Distribution Network and negative if it is withdrawn from such network. In case a Metering Point records separate values for Energy injected and withdrawn, the sign convention shall apply accordingly for each recorded value at the particular hour.

b.2. The total Generation by the relevant Generation Units of the Generation Plant shall be calculated as:

$$\text{TotalGenU}_{p,h} = \text{NetEnergy}_{p,h},\ \textit{if}\ \text{NetEnergy}_{g,h} > 0$$

$$\text{TotalGenU}_{p,h} = 0\ \textit{in all other cases}$$

Where:

- $TotalGenU_{p,h}$ *is the* quantum of Energy injected by all the running/synchronized Generation Units of a Generation Plant "p" whose Energy is measured by the Meters installed at the incoming/outgoing lines of the Generation Plant in hour "h";
- $NetEnergy_{p,h}$ is the quantum of Energy injected/withdrawn from the Transmission or Distribution Network by Generation Plant "*p*" in the hour "*h*", expressed in MWh calculated pursuant to Clause 5.2.1.1.b.1 above.

b.3. The Energy injected by Each Generation Unit of the Generation Plant shall be calculated as following:

$$GenU_{i,p,h} = TotalGenU_{p,h} * AC_{i,p,h}[MW] / \sum_{\forall i \epsilon p} AC_{i,p,h}$$

Where:

- *$GenU_{i,p,h}$ is the* quantum of Energy injected (Generation) into the Transmission or Distribution Network by Generation Unit "i" belonging to Generation Plant "p" in hour "h";
- *$TotalGenU_{p,h}$* is the quantum of Energy injected (Generation) into the Transmission or Distribution Network by all those Generation Units of Generation Plan "p" whose output is being measured by the Meters installed in the lines in hour "h";
- $AC_{i,p,h}$ shall be equal to:
  - the Available Capacity of relevant Generation Unit "i", belong to Generation Plant "p" in hour h, in MW, which is synchronized with the Grid System as per information communicated by the System Operator to the Market Operator;
  - The Dependable Capacity of the Generation Unit "i," belonging to Generation Plant "p" in hour "h", in MW which is synchronized with the Grid System in case the Available Capacity is not reported by the System Operator. Such cases may include the hydro units, ARE units, Generation Units running for testing purposes and Generation Units of Captive Generators etc;
- $\forall i \epsilon p$ means all those Generation Units of Generation Plant "p" which were synchronized with the Grid System for which the $TotalGenU_{p,h}$ was calculated as per Clause 5.2.1.1.b.2 above.

5.2.2. CALCULATION OF GENERATION BY EACH GENERATION PLANT

5.2.2.1. The Market Operator shall calculate the total Generation by a Generation Plant as the summation of the Generation of its each individual Generation Unit:

$$Gen_{p,h}(\text{MWh}) = \sum_{\forall i \epsilon p} GenU_{i,p,h}$$

Where:

- *$Gen_{p,h}$ is the* quantum of Energy injected (Generation) by Generation Plant "p"" in hour "h" expressed in (MWh);
- *$GenU_{i,p,h}$ is the* quantum of Energy injected (Generation) into the Transmission or Distribution Network by Generation Unit "i" belonging to Generation Plant "p" in hour "h" calculated pursuant to Clause 5.2.1.1.b.1or Clause 5.2.1.1.b.3 above, as the case may be.
- $\forall i \epsilon p$ means the addition over all Generation Units of Generation Plant "p"

5.2.3. CALCULATION OF BACK-FEED ENERGY FOR EACH GENERATION PLANT

5.2.3.1. The Market Operator shall calculate the Energy withdrawn from the Grid System in each hour by each Generation Plant as following:

a) In case there are dedicated Meters installed on the Generation Units of a Generation Plant, the value recorded by the Meters as provided by the Metering Service Provider shall be considered:

$$BFE_{p,h}[MWh] = \sum_{\forall i \in Gen_p} E_{MP\,i,p,h}$$

Where:

- $BFE_{p,h}$ *is the* quantum of Energy withdrawn (Back-Feed Energy) by Generation Plant "p" in hour "h" expressed in (MWh);
- $E_{Mpi,p,h}$ is the value of Energy withdrawn from the Transmission or Distribution Network, as provided by the Metering Service Provider according to the provisions of Chapter 4, at the Metering Point corresponding to the Generation Unit "i" belonging to Generation Plant "p" in the hour "*h*";
- $\forall\ i \in Gen_p$ means all Metering Points of the Generation Units "i" belonging to Generation Plant "p".

b) In case, there are no dedicated Meters installed on each Generation Unit of a Generation Plant and there are some Meters are installed at the incoming/outgoing lines that measures the combined input of more than one Generation Units of the Generation Plant and the Meters also record the incoming and outgoing Energy flowing through the lines, then in such case the Energy withdrawn shall be calculated as:

$$BFE_{p,h}[\text{MWh}] = -NetEnergy_{p,h}\ if\ \ NetEnergy_{g,h}\ < 0$$

$$BFE_{p,h}[\text{MWh}] = 0 \text{ in all other cases}$$

Where:

- $BFEP_h$ *is the* quantum of Energy withdrawn (Back-Feed Energy) by Generation Plant "p"" in hour "h" expressed in (MWh);
- $NetEnergy_{p,h}$ is the quantum of Energy injected/withdrawn from the Transmission or Distribution Network by Generation Plant "p" in the hour "h", expressed in MWh calculated pursuant to Clause 5.2.1.1.b.1 above;

5.2.3.2. For the calculations performed as per Section 5.2, the Imports shall also be considered as a Generation Unit or Generation Plant located at the interconnection point.

5.3. <u>CONSIDERATION OF DISTRIBUTION LOSSES</u>

5.3.1.1. For calculation of the Imbalances of Energy, it shall be considered that all transactions take place at the Transmission Network. However, if a Trading Point is located in the Distribution Network, the values obtained from such Trading Point shall be adjusted to take into account the losses in such network.

5.3.1.2. The adjustment for losses in the Distribution Network shall be as per the voltage levels specified in the determinations of the Authority and shall be based on the principle that the relevant loss shall be considered as per location of the Metering Point. In case there is no specific loss for a voltage level in the determination of the Authority, then the losses of the voltage level above shall be considered. For the avoidance of doubt, the location of the Metering Point shall not be interpreted as losses are being applied as per specific path of the Metering Point, however, the losses will be applied as per the postage stamp and the location shall only be considered whether the Metering Point is at the start of the voltage level or not for the application of respective loss of the relevant voltage level.

5.3.1.3. The adjustment, referred to in Clause 5.3.1.1 and Clause 5.3.1.2 above, shall be performed at all Trading Points located in the Distribution Network where Energy is withdrawn, which shall include:

a) BPCs enrolled as Market Participants or supplied electric power by Competitive Electric Power Suppliers;

b) Distribution Networks connected to another Distribution Network;

c) Export points located in the Distribution Network; and

d) A Generator receiving back-feed Energy which is not supplied by a Supplier of Last Resort.

5.3.1.4. The adjustment provided in Clause 5.3.1.3 above shall be calculated as:

a) Where the Trading Point is an interface of a BPC or an Export, where the Energy is withdrawn from the network, the adjustment shall be calculated as following:

$$Adj\_E_{i,d,h} = E_{MP_{i,d,h}}/(1 - DistLoss_{d,p})$$

Where:

- $Adj\_E_{i,d,h}$ is the Energy at the Trading Point *"i"*, at hour *"h"*, located in the network of Distribution Licensee "d", adjusted to take into account losses in the Distribution Network;
- $E_{MP\ i,d,h}$ is the value of Energy, as considered by the Market Operator as per provisions of Chapter 4, at the Trading Point "i", located in the network of Distribution Licensee "d" at hour "h";
- $DistLoss_{d,p}$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d" for the period "p" to which the hour "h" belongs, as determined by the Authority for the relevant Distribution Licensee. The values of the distribution loss coefficients shall be informed by the respective Suppliers of Last Resort/Distribution Licensees to the Market Operator. Any update in such values as approved by the Authority shall be communicated to the Market Operator by the respective Supplier of Last Resort/Distribution Licensee as soon as practicable.

b) Where the Trading Point is an interconnection between two Distribution Licensees, the adjustment shall be calculated as following:

$$Adj\_E_{i,d,h} = E_{MP_{i,d,h}}/(1 - DistLoss_{d,p})$$

Where:

- $Adj\_E_{i,d,h}$ is the Energy at the Trading Point *"i"*, at hour *"h"*, located in the network of Distribution Licensee "d", adjusted to take into account losses in the Distribution Network;
- $E_{MP\ i,d,h}$ is the value of Energy as considered by the Market Operator, as per provisions of Chapter 4, at the Trading Point "i", located in the network of Distribution Licensee "d" at hour "h";
- $DistLoss_{d,p}$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d", from whose network the Energy is being withdrawn,

for the period "p" to which the hour "h" belongs, as determined by the Authority for such Distribution Licensee.

c) For a Generator receiving Back-feed Energy which is not supplied by a Supplier of Last Resort, the adjustment shall be calculated as following;

$$Adj\_E_{p,d,h} = \sum_{\forall\, i\, \epsilon\, p} BFFU_{i,p,h} / (1 - DistLoss_{d,p})$$

Where:

- $Adj\_E_{p,d,h}$ is the Back-Feed Energy received by Generator "p" at the Trading Points at hour "h", located in the network of Distribution Licensee "d", adjusted to take into account losses in the Distribution Network;
- $BFFU_{i,p,h}$ is the value of Back-Feed Energy received by Generation Unit "i" belonging to Generator "p", located in the network of Distribution Licensee "d" at hour "h" calculated pursuant to Clause 5.2.3.1 above;
- $DistLoss_{d,p}$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d" for the period "p" to which the hour "h" belongs, as determined by the Authority for the relevant Distribution Licensee;
- $\forall\, i\, \epsilon\, p$ means all Generation Units belong to Generator "p" connected to the Distribution Network.

d) For all other Trading Points, there will be no adjustment:

$$Adj\_E_{i,d,h} = E_{MP_{i,d,h}}$$

Where:

- $Adj\_E_{i,d,h}$ is the Energy at the Trading Point "i", at hour "h", located in the network of Distribution Licensee "d", adjusted to take into account losses in the Distribution Network;
- $E_{MP\ i,d,h}$ is the value of Energy, as considered by the Market Operator as per provisions of Chapter 4, at the Trading Point "i", located in the network of Distribution Licensee "d" at hour "h".

5.4. CONSIDERATION OF THE TRANSMISSION LOSSES

5.4.1. CALCULATION OF THE TRANSMISSION LOSSES

5.4.1.1. The Metering Service Provider shall determine, on hourly basis, the quantum of losses in the Transmission Network for each Transmission Licensee being metered by it, by utilizing the metering information in accordance with Chapter 4.

5.4.1.2. The quantum of the losses in the Transmission Network shall be calculated individually for each Transmission Licensee as the difference between the total Energy injected into and withdrawn from its Transmission Network.

5.4.1.3. The quantum of the losses in the Transmission Network shall be calculated as:

$$TransLoss_{k,h}[MWh] = \sum_{\forall\, i\, \in\, MP_k} E_{MP_{i,k,h}}$$

Where:

- $TransLoss_{k,h}$ is the quantum of the losses in the Transmission Network of the Transmission Licensee "k" in the hour "h", expressed in MWh;
- $E_{Mpi,k,h}$ is the value of Energy, obtained by the Metering Service Provider from the Commercial Metering System according to the provisions of Chapter 4, at the Metering Point i, corresponding to the Transmission Service Provider k in the hour "h";
- $\forall\ i \in MP_k$ means all those Metering Points located at the boundaries of the Transmission Licensee k.

  Explanation:

  The Metering Points shall include:

  i. Interconnection of the Transmission Licensee with a Generator

  ii. Interconnection of the Transmission Licensee with another Transmission Licensee

  iii. Interconnection of Transmission Licensee with Distribution Licensee

  iv. Interconnection of the Transmission Licensee with the network of an entity from foreign countries of territories where the applicablility of the Act is not extended

5.4.1.4. Sign convention (1): For the application of the formula provided in Clause 5.4.1.3, the Energy recorded at each Metering Point at each particular hour shall be considered positive if it is injected into the Transmission Network of Transmission Licensee "k" and negative if it is withdrawn from such Transmission Network. In case a Metering Point records separate values for Energy injected and withdrawn, the sign convention shall apply accordingly for each recorded value at the particular hour.

5.4.1.5. The losses calculated pursuant to Clause 5.4.1.3 shall be submitted to the Market Operator by each Metering Service Provider within two (2) Business Days of end of every month.

5.4.2. CALCULATION OF TOTAL DEMAND

5.4.2.1. The Market Operator shall determine, on hourly basis, the Total Demand by subtracting the Transmission loss from total Energy generated by Generation Units or Generation Plants or Imports.

5.4.2.2. The Total Demand for the whole system shall be calculated as:

$$TotDem_h[MWh] = \sum_{GenP} GenP_h - \sum_{k} TransLoss_{k,h}$$

Where:

- $TotDem_h$ is the total Energy withdrawn by all Market Participants in hour "h" which shall be liable to cover the losses in the Transmission Network;
- $GenP_h$ is the Energy injected into the Transmission or Distribution Network by a Generation Plant in the hour "h" calculated pursuant to Clause 5.2.2.1;

- $TransLoss_{k,h}$ is the quantum of the losses in the Transmission Network of the Transmission Licensee "*k*" in the hour "*h*", expressed in MWh calculated pursuant to Clause 5.4.1.3;
- $\sum_{GenP}$ means addition over all Generators and Imports;
- $\sum_{k}$ means addition over all Transmission Licensees.

5.4.3. UPLIFT COEFFICIENT

5.4.3.1. An Uplift Coefficient shall be applied to the Energy supplied to Market Participants supplying the demand which shall be calculated as:

$$Uplift_{TransLoss,h} = \frac{\sum_{k} TransLoss_{k,h}[MWh]}{TotDem_{h}[MWh]}$$

Where:

- Σ_k means the addition over all Transmission Licensees;
- All other terms have the same meaning as defined above.

5.4.4. ASSIGN METERED VALUES TO MARKET PARTICIPANTS

5.4.4.1. The calculation of the Energy withdrawn by a Market Participant enrolled as Generators, Electric Power Supplier, a BPC which is a Market Participant or an Electric Power Trader involved in Export or representing Generators who are not Market Participants shall be done as following:

a) For a BPC which is a Market Participant, the Energy withdrawn values shall be calculated as follows:

$$Act\_E_{mp,h} = \sum_{\forall i \in MP} Adj\_E_{i,h}$$

Where:

- $Act\_E_{mp,h}$ is the total Energy withdrawn by a BPC "*mp*", in hour "*h*";
- $Adj\_E_{i,h}$ is the Energy, withdrawn at a Metering Point "i" by a BPC "*mp*", in hour "*h*", calculated pursuant to Clause 5.3.1.4;
- $\forall i \in MP$ means all those Metering Points through which the "BPC" has withdrawn Energy from the Grid.

b) For a Competitive Electric Power Supplier, the Energy withdrawn values shall be calculated as the addition of the Energy withdrawn at the corresponding Metering Point of each BPC or a Generator which is not a Market Participant and served by the Competitive Supplier through a Standardized Load Following Supply Contract:

$$Act\_E_{mp,h}[MWh] = \sum_{\forall BPC_i \in MP} Adj\_E_{i,h} + \sum_{\forall Genp \in MP} Adj\_E_{p,d,h}$$

Where:

$Act\_E_{mp,h}$ is the total Energy supplied by the Competitive Supplier "*mp*" to its BPCs and Generators, which are not Market Participants, in hour "*h*", in MWh;

$Adj\_E_{i,h}$ is the Energy withdrawn by BPC "i", which is not a Market Participant and has a Standardized Load Following Supply Contract with the Competitive Supplier "mp" in hour "h", calculated pursuant to Clause 5.3.1.4;

$Adj\_E_{p,d,,h}$ is the Energy withdrawn by Generator "i", which is not a Market Participant and has a Standardized Load Following Supply Contract with the Competitive Supplier "mp" in hour "h", calculated pursuant to Clause 5.3.1.4.c);

$\sum_{\forall BPC_i \in MP}$ means the addition over all BPCs "i" which are not Market Participants and supplied by the Competitive Supplier "mp" through a Standardized Load Following Contract;

$\sum_{\forall Gen_i \in MP}$ means the addition over all Generators "i" which are not Market Participants and supplied by the Competitive Supplier "mp" through a Standardized Load Following Contract.

c) For a Generator which is a Market Participant, the Energy withdrawn values shall be calculated as follows:

$$Act\_E_{mp,h} = \sum_{\forall p \epsilon MP} Adj\_E_{p,d,h}$$

Where:

$Act\_E_{mp,h}$ is the total Energy withdrawn by Generator mp" in hour "h", in MWh;

$Adj\_E_{p,d,h}$ is is the Energy withdrawn by Generation Plant "i", belonging to Generator "p" in hour "h", calculated pursuant to Clause 5.3.1.4.c);

$\sum_{\forall p \epsilon MP}$ means the addition over all Generation Plants belonging to Market Participant "mp".

d) For Electric Power Trader involved in Exports or representing Generators who are not Market Participants, the Energy withdrawn shall be calculated as following:

$$Act\_E_{mp,h}[MWh] = \sum_{\forall i \in MP} Adj\_E_{i,h} + \sum_{\forall Genp \in MP} Adj\_E_{p.d,h}$$

Where:

$Act\_E_{mp,h}$ the total Energy withdrawn by a Trader "mp" involved in Exports or representing Generators who are not Market Participant, *in hour "h"*;

$Adj\_E_{i,h}$ is the Energy, withdrawn at Each Trading Point "i" belong to the Trader "mp" in hour "h", calculated pursuant to Clause 5.3.1.4;

$Adj\_E_{p,d,h}$ is the Energy withdrawn by Generator *"i"*, which is not a Market Participant and is represented by Electric Power Trader *"mp"* in hour *"h"*, calculated pursuant to Clause 5.3.1.4.c);

$\sum_{\forall i \in MP}$ means the addition over all those Metering Points through which Trader involved in Export is Exporting Energy from the Grid;

$\sum_{\forall Gen_i \in MP}$ means the addition over all Generators *"i"* which are not Market Participants and represented by the Trader.

e) For Suppliers of Last Resort, the Energy withdrawn, shall be calculated by subtracting the Energy withdrawn by Market Participants located in the territory of the Supplier of Last Resort, from the total Energy injected into the network of the Supplier of Last Resort:

$$Act\_E_{mp,h}[MWh] = \sum_{\forall i \in \mathrm{mp}} Adj\_E_{i,h} + \sum_{\forall j \in mp} EMP_{j,h} - \sum_{\forall k \in mp} Act\_E_{k,h}$$

Where:

$Act\_E_{mp,h}$ is the total Energy withdrawn by the Supplier of Last Resort *"k"*, in hour *"h"*, in MWh;

$Adj\_E_{i,h}$ is the Energy Injected at the Trading Point *"i"*, which is a boundary of Supplier of Last Resort *"k"*, in hour *"h"*, calculated pursuant to Clause 5.3.1.4;

$EMP_{j,h}$ is the Energy injected at the Metering Point *"j"*, which is not a Trading Point, belonging to the Supplier of Last Resort *"k"*, in hour *"h"*, considered by the Market Operator in accordance with the Provisions of Chapter 4;

$Act\_E_{k,h}$ is the Energy withdrawn by Market Participant "k" located at the boundary of Supplier of Last Resort *"mp"*, in hour *"h"*, calculated pursuant to Clause 5.4.4.1.a), 5.4.4.1.b), 5.4.4.1.c)or 5.4.4.1.d), as the case may be:

$\sum_{\forall i \in \mathrm{mp}}$ means the addition over all Trading Points *"i"* which are located at the boundaries of the Supplier of Last Resort "mp";

$\sum_{\forall j \in mp}$ means the addition over all Metering Points which are not Trading Points, which are located in the service territory of the Supplier of Last Resort *"mp"*;

$\sum_{\forall k \in mp}$ means the addition over all Market Participant which are located at the boundary of Supplier of Last Resort *"mp"*;

5.4.5. CALCULATION OF THE ENERGY SUPPLIED OR WITHDRAWN (INCLUDING TRANSMISSION LOSSES) BY EACH MARKET PARTICIPANT

5.4.5.1. The calculation of the Energy supplied or withdrawn (including transmission losses) by a Market Participant which will be used for calculation of the Imbalance, shall be done as following:

$$ES_{i,h}[MWh] = Act\_E_{i,h} * (1 + Uplift_{TrasnLoss,h})$$

Where:

- $ES_{i,h}$ is the total Energy supplied or withdrawn by a Market Participant *"i"*, inclusive of transmission losses, in hour *"h"*, which will be used for calculation of the Imbalance;
- $Act\_E_{i,h}$ is the Energy, withdrawn by a Market Participant *"i"* in hour *"h"*, calculated pursuant to Clause 5.4.4.1;
- $Uplift_{TrasnLoss,h}$ is the Uplift Coefficient for hour "h", calculated pursuant to Clause 5.4.3.1.

5.5. DETERMINATION OF THE IMBALANCE AMOUNTS

5.5.1. DETERMINATION OF CONTRACTED QUANTITIES

5.5.1.1. The Market Operator shall calculate the energy bought and sold through registered Contracts among Market Participant at each Energy Balancing Period (one hour) using the information contained in the Contracts Register.

5.5.1.2. For each Market Participant, the Market Operator shall determine the Energy bought and sold through Contracts with other Market Participants on hourly basis as:

$$ET_{mp,h} = \sum_{\forall\, k \in C_{mp}} ETC_{mp,k,h}$$

Where:

- $ET_{mp,h}$ is the Energy bought and sold by the Market Participant "mp" through Contracts with other Market Participants during hour *h;*
- $ETCmp_{,k,h}$ is the Energy purchased or sold by the Market Participant "mp" through the Contract "*k*" during hour "*h*";
- $\forall\ k \in C_{mp}$ means all the Contracts of the Market Participant "mp" with other Market Participants through which it has bought or sold Energy.

5.5.1.3. Sign convention (2): For the application of the formula provided in Clause 5.5.1.2, the Energy purchased by a Market Participant in a Contract shall be considered positive and the Energy sold by a Market Participant in a Contract shall be considered negative.

5.5.2. DETERMINATION OF ENERGY IMBALANCES

5.5.2.1. The Market Operator shall calculate the Imbalance of Energy of each Market Participant on hourly basis: as the difference between the Energy injected by the Market Participant into the Grid System plus the Energy bought and sold through registered Contracts and the Energy supplied by such Market Participant calculated as:

$$Imb\_E_{mp,h}[MWh] = Gen_{mp,h}[MWh] + Imp_{mp,h}[MWh] + ET_{mp,h}[MWh] - ES_{mp,h}[MWh]$$

Where:

- $Imb\_E_{mp,h}$ is the Imbalance of Energy of Market Participant "*mp*" during hour "*h*" *in* MWh;

- $Gen_{mp,h}$ is the Energy injected into the Grid System by Market Participant "mp" during hour "h", in MWh;
- $Imp_{mp,h}$ is the actual energy Imported (injected into the Grid System), by Market Participant "mp" during hour "h", in MWh;
- $ET_{mp,h}$ is the Energy bought and sold through Contracts with other Market Participants, by the Market Participant "mp" during hour "h", calculated pursuant to Clause 5.5.1.2;
- $ES_{mp,h}$ is the Energy actually supplied (or exported) by the Market Participant "mp" during hour "h", calculated pursuant to Clause 5.4.4.1.

5.5.2.2. Sign convention (3):

a) A positive Imbalance indicates that the relevant Market Participant has either:

a.1. Injected into the Grid System, an Energy quantity greater than its contracted quantity; or

a.2. Withdrawn from the Grid System, an Energy quantity lesser than its contracted quantity.

b) A negative Imbalance indicates that the relevant Market Participant has either:

b.1. Injected into the Grid System, an Energy quantity lesser than its contracted quantity; or

b.2. Withdrawn from the Grid System, an Energy quantity greater than its contracted quantity.

5.6. DETERMINATION OF THE APPLICABLE SYSTEM MARGINAL PRICE

5.6.1.1. On daily basis and for each hour of the day, the System Operator shall calculate the System Marginal Price.

5.6.1.2. Within eighteen (18) months from the approval of this Code, the System Operator shall, in collaboration with the Market Operator, make and submit to the Authority for approval a methodology for determining the hourly System Marginal Price. Until such methodology is approved, the procedure included in Section 19.1 shall be used, as an interim measure, for calculation of the System Marginal Price.

5.6.1.3. On daily basis, the System Operator shall communicate to the Market Operator, the System Marginal Prices of the previous day. The Market Operator and the System Operator shall agree on the channels and formats for this communication.

5.7. DETERMINATION OF THE AMOUNTS RECEIVABLE AND AMOUNTS PAYABLE

5.7.1. CALCULATION OF AMOUNTS RECEIVABLE / PAYABLE

5.7.1.1. Within five (5) Business Days immediately after the end of each month, the Market Operator shall determine the Amounts Payable and Amounts Receivable of each Market Participant resulting from the administration of the Balancing Mechanism for Energy.

5.7.1.2. The Market Operator shall calculate such amounts as:

$$Bal\_Am_{mp,M}(PKR) = \sum_{h=1}^{Tot\_h} \left(Imb\_E_{mp,h}(MWh) * Marg_h({}^{PKR}/_{MWh}) \right)$$

Where:

- $Bal\_Am_{mp,M}$ is the final balance amount of Market Participant "mp" for the settlement month "*M*", as a result of administration of the Balancing Mechanism for Energy;
- $Imb\_E_{mp,h}$ is the Imbalance of Energy of Market Participant "*mp*" during hour "*h*" calculated pursuant to Clause 5.5.2.1;
- $Marg_h$ is the System Marginal Price for the hour "*h*", determined by the System Operator as per Section 5.6, expressed in PKR/MWh;
- *Tot_h* is the total number of hours in month "*M*".

5.7.1.3. For the application of Clause 5.7.1.2, a positive balance amount implies an Amount Receivable, and the Market Participant is entitled to receive a payment for such amount. A negative balance implies that the Market Participant is responsible for making a payment for such amount to the Market Operator.

5.8. APPLICABLE TAXES

5.8.1. APPLICABILITY OF TAXES

5.8.1.1. All Settlements calculated by the Market Operator pursuant to this Chapter shall be subject to the applicable taxes as per Applicable Law.

5.9. PUBLICATIONS OF BME RESULTS

5.9.1.1. On monthly basis the Market Operator shall document and make available to the relevant Market Participants the results of the BME.

5.9.1.2. The Market Operator shall publish, *inter alia*, the following:

a) The System Marginal Prices, for each hour of the previous month;

b) The Amounts Payable and Amounts Receivable of each Market Participant; and

c) Any other information, the Market Operator deems suitable for proper understanding of the published results.

5.9.1.3. The Market Operator shall provide to each Market Participant and other relevant stakeholders the following information:

a) the hourly metering data used for calculation of the Imbalances of Energy of such Market Participant;

b) the hourly values of the Energy actually injected into or withdrawn from the Grid System, by the Market Participant;

c) the hourly contracted quantities of such Market Participant which were used for calculating the Imbalances of Energy of such Market Participant; and

d) the hourly Imbalances of the Market Participant.

Chapter 6. ADDITIONAL MARKET CHARGES (ANCILLARY SERVICE CHARGES (ASC), TRANSMISSION MUST RUN AND RELIABILITY MUST RUN AND OPERATORS FEE)

6.1. PURPOSE

6.1.1.1. The purpose of this chapter is:

a) to provide a procedure for identification of the Generation Units which may be eligible for compensation for Transmission Must Run and Reliability Must Run and/or for allowing provision of Ancillary Services;

b) to determine the amount of compensation for Transmission Must Run and Reliability Must Run and/or for allowing provision of Ancillary Services; and

c) to provide a manner for charging the Market Operator Fee.

6.2. TRANSMISSION MUST RUN AND RELIABILITY MUST RUN

6.2.1. CONGESTED AREAS (TRANSMISSION MUST RUN)

6.2.1.1. Where dispatch of least cost Generation results in overloading of the network elements, lines and transformers which connect an area with the rest of the Grid System, such area shall be considered as Congested Area.

6.2.1.2. The System Operator shall alleviate Congestion in a Congested Area either by:

a) Dispatching Transmission Must Run, if the Congested Area is importing Energy from the rest of the Grid System; or

b) instructing one or more Generation Units located in the Congested Area to reduce Generation or disconnect from the network (Must Stop Generation) if the Congested Area is exporting Energy to the rest of the Grid System.

6.2.1.3. A Congested Area shall be considered severely Congested in the following cases:

a) the area has, on annual basis, Congestion in more than twenty percent (20%) of the Energy Balancing Periods; or

b) the cost for alleviation of Congestion exceeds (5%) of the cost of least cost dispatch without Congestion on annual basis.

6.2.1.4. Within three (03) months of the CMOD, the System Operator shall identify all severely Congested Areas and, in collaboration with the Market Operator, place them into different Congested Zones considering their location in the Grid.

6.2.1.5. The System Operator shall submit this information to the Authority for approval. The Market Operator shall consider the area as a Congested Zone for Settlement purposes, from 0:00 a.m. of the first day of the first month immediately after approval of the Authority.

6.2.1.6. Till the time the Authority approves the severely Congested Areas and Congested Zones, the provisions of Section 6.2 and Section 6.3 shall not apply.

6.2.1.7. A Congested Zone shall continue to be considered as a Congested Zone till the augmentation of the Transmission or Distribution Network or the installation of new control and protection devices show that Congestion is eliminated or significantly reduced. In such case, the System Operator, if required, delineate, in collaboration with the Market Operator, a new Congested Zone, considering the latest position of the Grid System and get it approved from the Authority and the Market Operator shall consider it as per provisions of Clause 6.2.1.5.

6.2.2. RELIABILITY AND SECURITY OF THE SYSTEM (RELIABILITY MUST RUN)

6.2.2.1. Where the dispatch of the least cost Generation Units results in violating the reliability and security criteria as specified in the Grid Code, the System Operator shall comply with the reliability and security criteria of the Grid Code by dispatching Generation Units which would not otherwise be dispatched if the reliability and security constraints were not binding.

6.2.3. IDENTIFICATION OF TRANSMISSION MUST RUN, RELIABILITY MUST RUN AND MUST STOP GENERATION

6.2.3.1. For each Dispatch Period, the System Operator shall clearly identify the Generation Units which shall be dispatched to alleviate Congestion (Transmission Must Run) or to satisfy the system security and reliability criteria of the Grid Code (Reliability Must Run) or the Generation Units which have to reduce their generation or may have to be disconnected to alleviate Congestion (Must Stop Generation).

6.2.3.2. On daily basis, the System Operator shall inform the Market Operator for Settlement purposes about all Generation Units which shall be considered as Transmission Must Run or Reliability Must Run or Must Stop Generation in each Dispatch Period of the previous day.

6.2.4. COMPENSATION FOR TRANSMISSION MUST RUN AND RELIABILITY MUST RUN

6.2.4.1. For each Energy Balancing Period, the System Operator shall calculate the Energy generated by a Generation Unit which has been identified as Transmission Must Run or Reliability Must Run by using the following information:

a) information available with the System Operator:

a.1. list of Generation Units entitled to receive compensation for Transmission Must Run or Reliability Must Run ;

a.2. if applicable, Energy that the Generation Unit would have produced if no instruction to increase the Generation had been issued by the System Operator, in case this value is different than zero;

b) information provided by the Metering Service Provider from the Commercial Metering System as per provisions of Chapter 4:

b.1. Energy actually injected into the Grid System by the Generation Unit, entitled to receive compensation for Transmission Must Run or Reliability Must Run in the relevant Energy Balancing Period.

6.2.4.2. The amount of Energy to be compensated to a Generation Unit identified as Transmission Must Run or Reliability Must Run shall be calculated as:

$$UPC\_MR_{j,h}[MWh] = EAG_{j,h} - EPG_{j,h}$$

Where:

$UPC\_MR_{j,h}$	is the amount of Energy to be compensated for Generation Unit "j", identified as Transmission Must Run or Reliability Must Run , in hour "h", in MWh;
$EAG_{j,h}$	is the Energy actually injected into the Grid System by the Generation Unit "j", in hour "h", in MWh;
$EPG_{j,h}$	is the Energy that the Generation Unit "j" would have injected into the Grid System if Congestion had not existed or the reliability or security constraints were not binding, calculated by the System Operator, in hour "h", in MWh.

6.2.4.3. For each Energy Balancing Period, the Market Operator shall calculate the economic compensation to be allocated to a Generator for its Generation Units which were considered as Transmission Must Run or Reliability Must Run:

$$MRC_{k,h}[PKR] = \sum_{j \in k} \left[UPC\_MR_{j,h}[MWh] * \left(VC_{i,h} - Marg_h({}^{PKR}/_{MWh})\right)\right]$$

Where:

$MRC_{k,h}$	is the hourly amount to be compensated to Generator "k" for Transmission Must Run or Reliability Must Run during hour "h", in PKR;
$UPC\_MR_{j,h}$	is the amount of Energy to be compensated for Generation Unit "j", considered Transmission Must Run or Reliability Must Run , in hour h, in MWh, calculated pursuant to Clause 6.2.4.2;
$Marg_h$	is the System Marginal Price of hour "h", determined by the System Operator pursuant to Section 5.6 and communicated to the Market Operator;
$VC_{i,h}$	is the Variable Generation Cost of Generation Unit "j" at hour "h", determined by the System Operator taking into consideration the operating conditions of the Generation Unit during the corresponding Dispatch Period expressed in PKR/MWh and communicated to the Market Operator;
$\sum_{j \in k}$	Means the summation over all units "j" that belongs to Generator "k".

6.2.4.4. The Market Operator shall calculate the total monthly economic compensation for Transmission Must Run or Reliability Must Run as:

$$MMRC_{k,m} = \sum_{h=1}^{T} MRC_{k,h}[PKR]$$

Where:

$MMRC_{k,m}$	is the amount to be compensated to Generator "k" for Transmission Must Run or Reliability Must Run, during the Settlement Period "m", in PKR;

$MRC_{k,h}$ is the hourly amount to be compensated to Generator "k" for Transmission Must Run or Reliability Must Run, during hour "h", in PKR calculated pursuant to Clause 6.2.4.3;

T is the total number of hours in the Settlement Period.

6.2.5. COMPENSATION AMOUNT FOR MUST STOP GENERATION

6.2.5.1. Must Stop Generation shall not be eligible to receive any compensation for following the instructions of the System Operator to reduce its generation below its Available Capacity or disconnection from the network.

6.3. ANCILLARY SERVICES

6.3.1. REQUIREMENT AND PROVISION OF ANCILLARY SERVICES

6.3.1.1. The definitions, types and minimum requirements of Ancillary Services, which may be scheduled by the System Operator, are provided in the Grid Code or its operational procedures.

6.3.1.2. For the purpose of this Code, the following types of Ancillary Services shall be considered:

a) Primary Operating Reserve;

b) Secondary Operating Reserve;

c) Replacement Reserve and Contingency Reserve (over separate time scales, collectively under "tertiary frequency control";

d) Voltage Support / Reactive Power Control; and

e) Black Start Capability.

6.3.1.3. The System Operator shall determine and schedule the required Ancillary Services while performing the Security Constrained Economic Dispatch, either the Day Ahead Schedule or the Real Time Dispatch as established in the Grid Code. In this regard, it is hereby clarified that obtaining the necessary Ancillary Services is an integral part of carrying out the Security Constrained Economic Dispatch.

6.3.1.4. The provision of Ancillary Services as provided in Clause 6.3.1.2.a) through d), within the limits set out in the Grid Code, is mandatory for all Generators and Transmission Service Providers, subject to technical requirements defined in the Grid Code, and shall be provided on the instructions of the System Operator, which shall be compensated as provided in Clause 6.3.1.5 below and the decision of the System Operator in this respect shall be binding.

6.3.1.5. Notwithstanding anything contained in Clause 6.3.1.4 above, a Market Participant may be eligible to receive an economic compensation for:

a) its revenue loss due to an instruction issued by the System Operator to generate below the maximum Available Capacity of a Generation Unit, while its Variable Cost is lower than the System Marginal Price, for providing one or more of the Ancillary Services provided in Clause 6.3.1.2.a) through d), or for allowing other Generation Units to provide them (Reduced Generation Compensation); and

b) being instructed to produce Energy by a Generation Unit including the instruction to start the Generation Unit, while its Variable Generation Cost is greater than the System Marginal Price, for providing one or more of the Ancillary Services provided in Clause 6.3.1.2.a) through d), or for allowing other Generation Unit to provide these services; and

c) for being able to provide Black Start, if such cost has been approved explicitly by the Authority as a separate component for payment.

6.3.1.6. The System Operator shall inform the Market Operator in case a Generator fails or refuses to provide required Ancillary Services for necessary action.

6.4. COMPENSATION FOR PROVISION OF ANCILLARY SERVICES

6.4.1. GENERATORS ENTITLED TO RECEIVE COMPENSATION

6.4.1.1. The System Operator shall identify and inform the Market Operator, on daily basis and for each Energy Balancing Period of the previous day, the Generation Units and determine the quantity of Energy for which a Generator may be eligible to receive compensations for:

a) provision of Ancillary Services; or

b) reducing or increasing their Energy production to allow other Generation Units to provide Ancillary Services.

6.4.1.2. Within eighteen (18) month from the approval of this Code, the System Operator shall make a CCOP whereby a procedure shall be devised to identify a Generator which may be eligible to receive the compensation as well as to determine the quantity of Energy for which compensation may be paid as provided in Clause 6.4.1.1above. Till such time, the procedure included in Section 19.1 shall be applicable and this information shall be provided to the Market Operator, on daily basis for the previous day and Clause 6.4.1.3 shall not apply.

6.4.1.3. The System Operator shall communicate to the Market Operator, on daily basis for the previous day, the quantity of Energy for which compensation may be paid to each Generator for each Generation Unit for providing, or allowing other Generation Units to provide, Ancillary Services.

6.4.1.4. The information related to the provision of Ancillary Services and compensation thereof shall be published on the System Operator's website, along with necessary supporting information.

6.4.2. COMPENSATION FOR REDUCING GENERATION

6.4.2.1. The System Operator shall calculate the Energy not generated by a Generator at each Energy Balancing Period (one hour), to allow the production of Ancillary Services and provide, using the following information:

a) Information already available with the System Operator:

a.1. list of Generation Units for which a Generator may be eligible to receive compensation for allowing the production of Ancillary Services, as per Clause 6.4.1.1;

a.2. Available Capacity of the Generation Unit for which a Generator may be eligible to receive compensation, for the relevant Energy Balancing Period;

b) Information provided by the Metering Service Provider from the Commercial Metering

System as per provisions of Chapter 4:

b.1. Energy actually produced by the Generation Unit for which a Generator may be eligible to receive compensation, for the relevant Energy Balancing Period.

6.4.2.2. Till the time the System Operator makes the CCOP as referred to in Clause 6.4.1.2, the System Operator shall determine the quantity of Energy for which compensation may be paid to a Generator for reduction of its Generation as under:

$$RG\_ASC_{i,h}[MWh] = 0.95 * AC_{i,h}[MW] * 1[h] - EAG_{i,h}[MWh]$$

Where:

$RG\_ASC_{i,h}$	is the quantity of Energy for which compensation may be paid to a Generation Unit *i*, in hour *h*, due to the reduction in the generation of Energy, to provide Ancillary Services or allowing the provision of Ancillary Services by other Generation Units, in MWh (Reduced Generation Compensation);
Aci,h	is the Available Capacity of Generation Unit i, in hour h, in MW, provided that in the case of ARE, the Available Capacity should be equal to the potential Energy that such Generation Unit would have injected into the Grid System as calculated by the System Operator. Till the time the CCOP indicated above is made, the potential Energy that the ARE Generation Unit would have injected into the Grid System shall be equal to the Energy forecasted by the System Operator for the relevant hour as per provisions of the Grid Code and the factor of 0.95 shall not apply. Provided that for the purpose of issuance of the Permanent Firm Capacity Certificates, this aspect of ARE Generators shall not be considered as a type of Ancillary Service;
EAGi,h	is the Energy injected into the Grid System by Generation Unit i, in hour "h", in MWh, as provided by the Metering Service Provider as per provision of Chapter 4;
0.95	is a factor that considers the provision of Primary Operating Reserve by all Generation Units.

6.4.3. Compensation for Increased Generation

6.4.3.1. The System Operator shall calculate the Energy injected into the Grid by a Generation Unit, whose Variable Generation Cost is above the System Marginal Price, for each Energy Balancing Period (one hour), for allowing the provision of Ancillary Services, using the following information:

a) information already available with the System Operator:

a.1. List of Generation Units for which a Generator may be eligible to receive compensation for allowing the provision of Ancillary Services, as per Clause 6.4.1.1;

a.2. Energy that the Generation Unit would have produced if no Ancillary Services had been required;

b) information from the Commercial Metering System as per provisions of Chapter 4:

b.1. Energy actually injected into the Grid System by the Generation Unit, for which a Generator may be eligible to receive compensation, during the relevant Energy Balancing Period.

6.4.3.2. Till the time, the System Operator makes the CCOP as referred to in Clause 6.4.1.2, the System Operator shall determine the quantity of Energy for which compensation may be paid to Generators which have been dispatched for allowing the provision of Ancillary Services as under:

$$UPC\_ASC_{j,h}[MWh] = EAG_{j,h}[MWh] - EPG_{j,h}[MWh]$$

Where:

$UPC\_ASC_{j,h}$ is the quantity of Energy for which compensation may be paid to Generation Unit "j", in hour h, due to the increase in the generation of Energy having Variable Generation Costs above the System Marginal Price, to allow the provision of Ancillary Services, in MWh (Variable Cost Compensation);

$EAG_{j,h}$ is the Energy injected into the Grid System by Generation Unit "j", in hour "h", in MWh, provided by the Metering Service Provider as per provisions of Chapter 4;

$EPG_{j,h}$ is the amount of Energy that Generation Unit "j", in hour "h", would have injected into the Grid System if there had been no requirements of providing Ancillary Services (in MWh). The value of $EPG_{j,h}$ will be zero (0.0) unless the System Operator consider it appropriate to use a different value, clearly stating the reasons for this value being used.

6.4.4. Total Compensation for Provision of Ancillary Services

6.4.4.1. The Market Operator shall determine the compensation which may be paid to a Generator, for each Energy Balancing Period, for allowing the provision of Ancillary Services as under:

$$AC_{k,h}[PKR] = \sum_{i \in k}\left[RG\_ASC_{i,h} * \left(Marg_h - VC_{i,h}\right)\right] + \sum_{j \in k}\left[UPC\_ASC_{j,h} * \left(VC_{j,h} - Marg_h\right)\right]$$

Where:

$AC_{k,h}$ is the hourly amount which may be paid as compensation to Generator "k" during hour "h" for the provision of Ancillary Services, in PKR;

$RG\_ASC_{i,h}$ is the amount of Energy for which compensation may be paid to Generation Unit "i", during hour h, due to the reduction in the Energy generation, to allow the provision of Ancillary Services, in MWh, calculated pursuant to Clause 6.4.2.2;

$UPC\_ASC_{j,h}$ is the amount of Energy for which compensation may be paid to Generation Unit "j", in hour h, due to the increase in the Energy generation having Variable Generation Costs above the System Marginal Price, to allow the provision of Ancillary Services, calculated pursuant to Clause 6.4.3.2, in MWh;

$Marg_h$ is the System Marginal Price of hour "h", determined by the System Operator pursuant to Section 5.6, in PKR/MWh and communicated to the Market Operator;

$VC_{i,h}$ is the Variable Generation Cost of Generation Unit "j" during hour "h", communicated by the System Operator to the Market Operator, in PKR/MWh;

$VC_{j,h}$	is the Variable Generation Cost of Generation Unit *"j"* during hour *"h"*, communicated by the System Operator to the Market Operator, in PKR/MWh;
$\sum_{i \in k}$	is the sum over all Generation Units *"i"* which belongs to Generator *"k"* which have Variable Generation Cost lover than the System Marginal Price;
$\sum_{j \in k}$	is the sum over all Generation Units *"j"* which belongs to Generator *"k"* which have Variable Generation Cost higher than the System Marginal Price.

6.4.4.2. The Market Operator shall determine the total monthly compensation to a Generator, for the provision of Ancillary Services, as the sum, over all the hours of the Energy Settlement Period, of the hourly compensation as provided in Clause 6.4.4.1, plus the additional compensations as provided in Clause 6.4.4.3 below, if applicable.

6.4.4.3. Generators which were instructed by the System Operator to start a Generation Unit and connect it to the Grid System, for allowing the provision of Ancillary Services may be eligible to receive an additional compensation for such additional number of starts.

6.4.4.4. For cases where Clause 6.4.4.3 above is applicable, the System Operator shall inform the Market Operator, at the end of each month:

a) the list of Generators which may be eligible to receive compensation for the number of starts of a Generation Unit, for allowing the provision of Ancillary Services;

b) the total number of starts, for allowing the provision of Ancillary Services, of the Generation Unit, during the previous calendar month;

c) the unitary cost for each start of the relevant Generation Unit, which shall be:

c.1. the cost as agreed in the PPA, for Legacy Contracts-CPPA-G, Legacy Contract-DISCOs or Legacy Contract-KE, as the case may be, which explicitly state this as an item for payment;

c.2. for contracts not falling under 6.4.4.4.c.1 above, the start-up cost of the relevant Generation Unit, communicated by the Generator to the System Operator. The System Operator shall verify the appropriateness and adequacy of the start-up cost communicated by the Generator before registering it in the relevant database.

6.4.4.5. The total monthly compensation to a Generator for the provision of Ancillary Services shall be calculated as under:

$$MAC_{k,m} = \sum_{h=1}^{T} AC_{k,h}[PKR] + \sum_{i \in k}(NS_i * SC_i) + BSC_k$$

Where:

$MAC_{k,m}$	is the amount for which compensation may be paid to Generator *"k"* during the Settlement Period *"m"* for allowing the provision of Ancillary Services, in PKR;
$AC_{k,h}$	is the hourly amount for which compensation may be paid to Generator *"k"* during hour "h" for allowing the provision of Ancillary Services, in PKR, calculated pursuant to Clause 6.4.4.1;

NS_i	is the number of starts of Generation Unit "i" belonging to Generator "k" for allowing the provision of Ancillary Services, during the Settlement Period as provided by the System Operator pursuant to Clause 6.4.4.4;
SC_i	Start-up cost of Generation Unit "i", informed by the System Operator to the Market Operator pursuant to Clause 6.4.4.4.c);
BSC_k	monthly payments to Generator "k" for the provision of Black Start Capability. This value will be zero, unless such cost has been approved explicitly by the Authority as a separate component for payment;
$\sum_{i \in k}$	is the sum over all Generation Units "i" which belongs to Generator "k";
T	is the total number of hours in the Settlement Period.

6.5. DETERMINATION OF THE AMOUNTS RECEIVABLE AND PAYABLE FOR ASC AND TRANSMISSION MUST RUN AND RELIABILITY MUST RUN

6.5.1. ASSIGNING COMPENSATION FOR PROVISION OF ANCILLARY SERVICES, TRANSMISSION MUST RUN AND RELIABILITY MUST RUN TO MARKET PARTICIPANTS (AMOUNTS RECEIVABLE)

6.5.1.1. Within five (5) Business Days immediately after the end of each month, the Market Operator shall determine the compensation for Generators which are eligible to receive such compensation for allowing the provision of Ancillary Services, Transmission Must Run and Reliability Must Run and it shall assign such compensation to the relevant Market Participants as an Amount Receivable.

6.5.1.2. The Market Operator shall assign the compensation referred to in Clause 6.5.1.1 above, as under:

a) Where a Market Participant, which owns the Generation Unit or the Generation Plant, has not registered a Contract with the Market Operator, the Market Operator may assign the compensation (Amount Receivable) to such Market Participant; and

b) Where a Market Participant, which owns the Generation Unit or Generation Plant, has registered one or more Contracts with the Market Operator, the Market Operator may assign the right to receive such compensation (Amounts Receivable) either to the Generator or to the other party as per information available in the Contract Register.

6.5.2. ALLOCATION OF AMOUNT OF COMPENSATION FOR PROVISION OF ANCILLARY SERVICES, TRANSMISSION MUST RUN AND RELIABILITY MUST RUN AMONG MARKET PARTICIPANTS

6.5.2.1. Within five (5) Business Days immediately after the end of each month, the Market Operator shall allocate the amount for payment of compensation for the provision of Ancillary Services, Transmission Must Run and Reliability Must Run among all Market Participants which represent demand in each Congested Zone, on pro rata basis based on the total Energy withdrawn during the relevant Settlement Period (Amounts Payable). The Market Operator may adjust each component of the compensation for Transmission Must Run, Reliability Must Run and Ancillary Services in order to comply with the applicable tax laws of Pakistan.

6.5.2.2. The allocation of the amount of compensation as provided in Clause 6.5.2.1 shall be made as under:

a) determination of the total Energy supplied by each Market Participant enrolled as Electric Power Supplier or withdrawn by a BPC which is a Market Participant or Electric Power Trader involved in Exports or representing Generation or a Generator withdrawing back feed Energy in each Congested Zone. The calculation will be different in case of BPCs, Generators, Competitive Electric Power Suppliers, Suppliers of Last Resort, and Electric Power Traders involved in Exports or representing Generators:

a.1. In the case of a BPC which is a Market Participant, the Energy withdrawn shall be the Energy registered at the corresponding Metering Points as considered by the Market Operator as per provisions of Chapter 4:

$$ES\_BPC_{i,z,m}[MWh] = \sum_{h=1}^{T} Act\_E_{MP_{i,z,h}}$$

Where:

$ES\_BPC_{i,z,m}$ is the total Energy supplied to BPC *"i"*, which is located in the Congested Zone "z", during the Settlement Period *"m"*, in MWh;

$Act\_E_{MP_{i,z,h}}$ is the Energy, withdrawn by BPC *"i"*, which is located in the Congested Zone "z", in hour *"h"*, calculated pursuant Clause 5.4.4.1.a), in MWh;

T is the total number of hours in the Settlement Period *"m"*.

a.2. In the case of a Generator which is a Market Participant, the Energy withdrawn shall be the Energy registered at the corresponding Metering Points considered by the Market Operator as per provisions of Chapter 4:

$$ES\_Gen_{j,z,m}[MWh] = \sum_{h=1}^{T} Act\_E_{MP_{j,z,h}}$$

Where:

$ES\_Gen_{j,z,m}$ is the total Energy supplied to Generator *"j"*, which is located in the Congested Zone "z", during the Settlement Period *"m"*, in MWh;

$Act\_E_{MP_{j,z,h}}$ is the Energy, withdrawn by Generator *ji"*, which is located in the Congested Zone "z", in hour *"h"*, calculated pursuant Clause 5.4.4.1.c) in MWh;

T is the total number of hours in the Settlement Period *"m"*.

a.3. In the case of Competitive Electric Power Suppliers, the Energy supplied shall be the addition of the Energy supplied to all the BPCs or Generators, who are not Market Participants, and supplied by the Competitive Electric Power Supplier.

$$ES\_CS_{k,z,m}[MWh] = \sum_{h=1}^{T} Act\_E_{MP_{i,z,h}}$$

Where:

$ES\_CS_{j,z,m}$ is the total Energy supplied by the Competitive Supplier "j", to its customers, located in the Congested Zone "z", during the Settlement Period "m", in MWh;

$Act\_E_{MP_{i,z,h}}$ is the Energy supplied to BPC "i" or Generator "i", located in the Congested Zone "z", by Competitive Supplier "k" in hour "h", in MWh, calculated pursuant Clause 5.4.4.1.b) ;

T is the total number of hours in the Settlement Period "m".

a.4. In the case of Suppliers of Last Resort, the Energy supplied shall be calculated through an appropriate balance of the total Energy taken by the Supplier of Last Resort from the Transmission Network or Imports plus the Energy injected by Generation Units connected at the Distribution Network owned or contracted by the Supplier of Last Resort:

$$ES\_SLR_{l,z,m}[MWh] = \sum_{h=1}^{T} Act\_E_{MP_{l,z,h}}$$

Where:

$ES\_SLR_{k,z,m}$ is the total Energy supplied by the Supplier of Last Resort "k", to its consumers located in the Congested Zone "z", during the Settlement Period "m", in MWh;

$Act\_E_{MP_{i,z,h}}$ is the Energy withdrawn through Metering Points, belonging to the Supplier of Last Resort "l", located in the Congested Zone "z", in hour "h", calculated pursuant to Clause 5.4.4.1.e), in MWh;

T is the total number of hours in the Settlement Period "m".

a.5. In the case of Electric Power Traders involved in Exports or representing Generators, the Energy demanded shall be the Energy registered at the corresponding Metering Point:

$$ES\_Trader_{n,z,m}[MWh] = \sum_{h=1}^{T} Act\_E_{MP_{n,z,h}}$$

Where:

$ES\_EXPTrader_{l,z,m}$ is the total Energy supplied by the Electric Power Trader "n", which is located in the Congested Zone "z", during the Settlement Period "m", in MWh;

$Act\_E_{MP_{n,z,h}}$ is the Energy exported by the Electric Power Trader "n", or the Energy withdrawn by Generators represented by the Trader which are located in the Congested Zone "z", in hour "h", calculated pursuant Clause 5.4.4.1.d);

T is the total number of hours in the Settlement Period "m".

b) the total demand of the Congested Zone "z" shall be calculated as:

$$TD_{z,m} = \sum_{i} ES\_BPC_{i,z,m} + \sum_{j} ES\_Gen_{j,z,m} + \sum_{k} ES\_CS_{k,z,m} + \sum_{l} ES\_SLR_{l,z,m} + \sum_{n} ES\_Trader_{n,z,m}$$

Where

$TD_{z,m}$ is the total demand of the Congested Zone "z", during the Settlement Period *"m"*, in MWh;

$\sum_i$ is the sum over all BPCs which are Market Participants;

$\sum_j$ is the sum over all Generators which are Market Participants;

$\sum_k$ is the sum over all Competitive Electric Power Suppliers;

$\sum_l$ is the sum over all Suppliers of Last Resort;

$\sum_n$ is the sum over all Electric Power Traders which are performing Exports and/or representing Generators.

c) The total Energy of a Congested Zone for which charges to be paid as compensation to Generators for allowing the provision of Ancillary Services, Transmission Must Run and Reliability Must Run in each Congested Zone shall be calculated as:

$$TotalEC_{z,m}[MWh] = TD_{z,m} + \sum_{h}^{T} \sum_{\forall i \in z} Adj\_E_{i,z,h}$$

Where:

$TotalEC_{z,m}$ is the total Energy consumed within the Congested Zone "z" and exported to other Congested Zones in Settlement Period *"m"*, in MWh;

$TD_{z,m}$ is the total Energy consumed/ supplied by the Market Participant *"i"*, in the Congested Zone "z", during the Settlement Period *"m"*, in MWh calculated pursuant to Clause 6.5.2.2;

$Adj\_E_{i,z,h}$ is the Energy withdrawn/injected at the Metering Points "i", at hour "h", located at the boundary of the Congested Zone "z" with other Congested Zones, in MWh calculated pursuant to Clause 5.3.1.4;

$\forall\ i \in z$ means all Metering Points located at the boundary of the Congested Zone "z";

T is the total number of hours in the Settlement Period *"m"*.

Sign convention: For the calculation of the $Adj\_E_{i,z,m}$, the Energy registered at each Trading Point at each particular hour shall be considered positive if it is withdrawn from the Congested Zone "z" and negative if it is injected into the Congested Zone. In case a Metering Point records separate values for Energy injected and withdrawn, the sign convention shall apply accordingly for each recorded value at the particular hour, provided that if there are multiple Metering Points located at the same station, the net injection or withdrawal on station basis shall be considered instead of individual injections or withdrawals on each Meter.

d) the per unit charge on Energy for each Congested Zone shall be calculated as:

$$PUC_{z,m}[PKR] = \left(\frac{\sum_{\forall k \in z}(MAC_{k,m} + MMRC_{k,m})}{TotalEC_{z,m}}\right)$$

Where:

$PUC_{z,m}$ is the per unit charge applicable on each unit of Energy consumed within the Congested Zone "z" or exported to other Congested Zones for compensation to Generators located in the Congested Zone "z" for allowing the provision of Ancillary Services, Transmission Must Run or Reliability Must Run in Settlement Period "m", in PKR;

$MAC_{k,m}$ is the amount for which compensation may be paid to Generator "k" during the Settlement Period "m" for allowing the provision of Ancillary Services, calculated as per Clause 6.4.4.5;

$MMRC_{k,m}$ is the amount for which compensation may be paid to Generator "k" during the settlement period "m" for Transmission Must Run or Reliability Must Run, calculated as per Clause 6.2.4.4;

$TotalEC_{z,m}$ is the total Energy consumed within the Congested Zone "z" or exported to other Congested Zones in Settlement Period "m", in PKR calculated pursuant to Clause 6.5.2.2.c);

$\forall k \in z$ means all Generators connected to a network located in the Congested Zone "z", which are eligible for compensation for allowing the provision of Ancillary Services, Transmission Must Run or Reliability Must Run;

e) The charge applicable on Energy exports between Congested Zones shall be calculated as:

$$COE_{k,l,m} = PUC_{z,m} * \sum_{h}^{T} \sum_{\forall i \in k,l} Adj\_E_{i,h,m}$$

Where:

$COE_{k,l,m}$ is the total charge applicable on Energy withdrawn from Congested Zone "k" by the Congested Zone "l" in the Settlement Period "m", in PKR;

$Adj\_E_{i,h,m}$ is the Energy withdrawn from Congested Zone "k" at the Trading Point "i", at hour "h", located at the boundary between Congested Zone "k" and Congested Zone "l", during the Settlement Period "m", in MWh calculated pursuant to Clause 5.3.1.4;

$\forall i \in k,l$ means all Metering Points located at the boundary between Congested Zone "k" and Congested Zone "l";

All other terms have the same meaning as described above.

f) the total amount of compensation for allowing the provision of Ancillary Services, Transmission Must Run and Reliability Must Run in each Congested Zone shall be calculated as:

$$TAC_{z,m}[PKR] = \sum_{\forall k \in z} (MAC_{k,m} + MMRC_{k,m}) - \sum_{l} COE_{z,l,m} + \sum_{n} COE_{z,n,m}$$

Where:

$TAC_{z,m}$ is the total amount for which compensation may be paid to Generators located in the Congested Zone "z", for allowing the provision of Ancillary Services, Transmission Must Run and Reliability Must Run in the Settlement Period "*m*", in PKR;

$COE_{z,l,m}$ is the per charge applicable on Energy withdrawn from Congested Zone "z" by the Congested Zone "l" in the Settlement Period "*m*", in PKR;

$COE_{z,n,m}$ is the per charge applicable on Energy withdrawn by Congested Zone "z" from the Congested Zone "n" in the Settlement Period "*m*", in PKR;

$\sum_l$ means the addition over all Congested Zones "l" which have withdrawn Energy from the Congested Zone "z" during the Settlement Period "m";

$\sum n$ means the addition over all Congested Zones "n" from which the Congested Zone "z" has withdrawn Energy during the Settlement Period "m";

All other terms have the same meaning as described above.

g) the charges applicable to each Market Participant enrolled as Electric Power Supplier or BPC or Electric Power Traders involved in Exports or representing Generators shall be calculated as:

g.1. For a BPC which is a Market Participant:

$$TC\_BPC_{i,m}[PKR] = \sum_{z=1}^{n} \left[\frac{ES\_BPC_{i,z,m}}{TD_{z,m}} * TAC_{z,m} \right]$$

g.2. For Generators drawing back-feed Energy:

$$TC\_Gen_{j,m}[PKR] = \sum_{z=1}^{n} \left[\frac{ES\_Gen_{j,z,m}}{TD_{z,m}} * TAC_{z,m} \right]$$

g.3. For a Market Participant enrolled as Competitive Electric Power Supplier:

$$TC\_CS_{k,m}[PKR] = \sum_{z=1}^{n} \left[\frac{ES\_CS_{k,z,m}}{TD_{z,m}} * TAC_{z,m} \right]$$

g.4. For a Market Participant enrolled as Supplier of Last Resort:

$$TC\_SLR_{l,m}[PKR] = \sum_{z=1}^{n} \left[\frac{ES\_SLR_{l,z,m}}{TD_{z,m}} * TAC_{z,m} \right]$$

g.5. For a Market Participant enrolled as Electric Power Trader with Exports and/or representing Generators:

$$TC\_Trader_{n,m}[PKR] = \sum_{z=1}^{n} \left[\frac{ES\_Trader_{n,z,m}}{TD_{z,m}} * TAC_{z,m} \right]$$

Where:

$TC\_BPC_{i,m}$ are the total charges to be applied to Market Participant "i", enrolled with the Market Operator as BPC, for Ancillary Services, Transmission Must Run and Reliability Must Run, in the Settlement Period "m", in PKR;

$TC\_Gen_{j,m}$ are the total charges to be applied to Market Participant "j", enrolled with the Market Operator as Generator, for Ancillary Services, Transmission Must Run and Reliability Must Run, in the Settlement Period "m", in PKR;

$TC\_CS_{k,m}$ are the total charges to be applied to Market Participant "k", enrolled with the Market Operator as Competitive Electric Power Supplier, for Ancillary Services, Transmission Must Run and Reliability Must Run, in the Settlement Period "m", in PKR;

$TC\_SLR_{l,m}$ are the total charges to be applied to Market Participant "l", enrolled with the Market Operator as Supplier of Last Resort, for Ancillary Services, Transmission Must Run and Reliability Must Run, in the Settlement Period "m", in PKR;

$TC\_TraderE_{n,m}$ are the total charges to be applied to Market Participant "n", enrolled with the Market Operator as Electric Power Trader and involved in Exports and or representing Generation, for Ancillary Services, Transmission Must Run and Reliability Must Run, in the Settlement Period "m", in PKR;

$TAC_{z,m}$ is the total amount to be compensated to Generators located in the Congested Zone "z", for provision of Ancillary Services, Transmission Must Run and Reliability Must Run in the Settlement Period "m", calculated pursuant to Clause 6.5.2.2.f);

$TD_{z,m}$ is the total demand in the Congested Zone "z", in the Settlement Period "m", calculated pursuant to Clause 6.5.2.2.b);

$\sum_{z=1}^{n}$ means the addition of all the Congested Zones of Pakistan.

6.5.3. PUBLICATION OF ANCILLARY SERVICES, TRANSMISSION MUST RUN AND RELIABILITY MUST RUN RESULTS

6.5.3.1. The Market Operator shall document and share with all Market Participants, the results of the calculation of Amounts Payable and Amounts Receivable, for the provision of Ancillary Services and Must Run Generation, on monthly basis.

6.5.3.2. The information that the Market Operator shall share with the Market Participants may include:

a) the compensation that Generators may be eligible to receive for provision of Ancillary Services, Transmission Must Run and Reliability Must Run, for each Generation Unit;

b) the assigning of the compensations to Generators or to other Market Participants;

c) the Amounts Payable and Amounts Receivable by each Market Participant; and

d) Any other relevant information.

6.6. OPERATORS FEE

6.6.1. MARKET OPERATOR FEE

6.6.1.1. The Market Operator shall charge the Market Operator Fee payable by relevant Market Participants, in accordance with the determination of the Authority. The following costs associated with the services being rendered by the Market Operator, may be included in the petition for the Market Operator Fee:

a) general establishment and administration expenses;

b) repair and maintenance;

c) insurance;

d) depreciation, if any;

e) financial charges and other relevant costs;

f) any estimated future capital expenditures required for compliance with the provisions in this Code; and

g) any other relevant charges.

6.7. APPLICABLE TAXES

6.7.1. APPLICABILITY OF TAXES

6.7.1.1. All Settlements calculated by the Market Operator pursuant to this Chapter shall be subject to the applicable taxes as per Applicable Law.

Chapter 7. MONTHLY SETTLEMENT (MARKET PARTICIPANTS AND SERVICE PROVIDERS)

7.1. PURPOSE

7.1.1.1. The purpose of this Chapter is to provide a procedure for administration of a Market Settlement System to issue the monthly Settlement Statements to Market Participants.

7.2. MARKET SETTLEMENT SYSTEM

7.2.1. MARKET SETTLEMENT SYSTEM ADMINISTRATION

7.2.1.1. The Market Operator shall establish and administer a Market Settlement System for administration of the market and shall be responsible for the development and maintenance of the required digital infrastructure for the operation of the Market Settlement System.

7.2.1.2. The Market Operator shall be responsible for verification of data and the accuracy of the outputs of the Market Settlement System, which, shall be based on:

a) the relevant legal instruments;

b) the information provided by the Metering Service Providers;

c) the information provided by the System Operator;

d) the information available in the Market Participants Register as well as Contract Register; and

e) the information available in any other database of the Market Operator.

7.2.2. MARKET SETTLEMENT SYSTEM FUNCTIONS

7.2.2.1. The Market Settlement System shall be capable to perform the following functions:

a) calculate the settlement of the Balancing Mechanism for Energy, for all Market Participants according to the provisions of Chapter 5;

b) calculate the settlement of the Balancing Mechanism for Capacity, for all Market Participants according to provisions of Chapter 11;

c) calculate the settlement of the Ancillary Services, Transmission Must Run and Reliability Must Run, for all Market Participants according to provisions of Chapter 6;

d) calculate the accrued Default Interest payable to or by the Market Participants, as provided in Clauses 7.2.3.1 and 7.2.3.2; and

e) calculate the Market Operator Fee.

7.2.2.2. The Settlement of charges to be paid to or by a Market Participant, for a month, shall include the Amounts Payable or Amounts Receivable by the Market Participant, as the case may be, for:

a) its participation in the Balancing Mechanism for Energy, duly calculated as per Section 5.7;

b) dispatch of Transmission Must Run, Reliability Must Run and the Ancillary Services, calculated as per Chapter 6;

c) the Market Operator Fee;

d) if applicable, the amount payable by the Market Participant for the provision of Metering Services;

e) corrections which arise from Extra Ordinary Settlement Statements as provided in Sub-Section 7.3.4; and

f) accrued interest for previous payments not made or received on time.

7.2.3. ADDITIONAL CHARGES AND PAYMENTS

7.2.3.1. As provided in Sub-Section 12.3.6, the Market Operator may recover from a Market Participant:

a) actual costs (if any) incurred by the Market Operator for administration of Security Covers and Settlement Guarantee Cover in case of non-payment; and

b) Default Interest on any late payments.

7.2.3.2. The Market Operator shall determine the Default Interest for any payment not paid at the Payment Due Date by a Market Participant and shall charge it to such Market Participants.

7.3. SETTLEMENT STATEMENTS

7.3.1. PRELIMINARY SETTLEMENT STATEMENTS

7.3.1.1. Within ten (10) Business Days of the beginning of each month, the Market Operator shall send, through electronic means, to each Market Participant and Service Provider, a Preliminary Settlement Statement for the results of the Settlements of the previous month.

7.3.1.2. The Preliminary Settlement Statement for a Market Participant shall, at least, include:

a) the results of the Balancing Mechanism for Energy:

a.1. the hourly values of the Energy injected or withdrawn from the Grid System during the Settlement Period;

a.2. the Energy sold and bought through Contracts, registered with the Market Operator, for each hour of the Settlement Period;

a.3. the hourly Energy Imbalances;

a.4. the System Marginal Price for each hour of the Settlement Period; and

a.5. the total Amount Payable or Amount Receivable;

a.6. the Transmission losses and the Transmission and Distribution Loss Factors used in the calculations;

b) the compensation for Transmission Must Run, Reliability Must Run and Ancillary Services for the Settlement Period;

c) the Market Operator Fee;

d) the payable or accrued interest for previous payments not made on time; and

e) any adjustment resulting from an Extraordinary Settlement Statement.

7.3.2. CLAIMS AGAINST THE PRELIMINARY SETTLEMENT STATEMENTS

7.3.2.1. Where a Market Participant considers that an error or discrepancy exists in the Preliminary Settlement Statement, it shall submit to the Market Operator a written Review Request within (five (5)) Business Days of receipt of the Preliminary Settlement Statement.

7.3.2.2. The Review Request shall clearly state the Settlement Period, Dispatch Day, the issuance date of the Preliminary Settlement Statement, the item claimed, the reasons for the claim, the amount claimed, and shall be accompanied with supporting documents.

7.3.2.3. After receipt of the Review Request, the Market Operator shall review the request and decide whether there is any error or discrepancy in the Preliminary Settlement Statement and if required, it may hold a meeting with the relevant Market Participant to settle the matter. If the Market Operator does not agree with the Review Request, it shall intimate the same to the relevant Market Participants along with reasons thereof.

7.3.2.4. Where the market operator, after review of the Preliminary Settlement Statement finds that there is an error or discrepancy as claimed by the relevant Market Participant, it shall rectify the error before issuing the Final Settlement Statement and shall inform all the relevant Market Participants accordingly.

7.3.3. FINAL SETTLEMENT STATEMENTS

7.3.3.1. On or before 25th day of each month, the Market Operator shall issue the Final Settlement Statement to each Market Participant, using a format similar to the Preliminary Settlement Statement.

7.3.3.2. A Market Participant may challenge the Final Settlement Statement along with reasons thereof within (15) Business Days of its issuance. The challenge may relate to:

a) the metered values and contracted quantities of Energy; or

b) the settled amounts, either for Imbalances, Market Operator's Fee, if applicable, System Operator's Fee, Default Interest for late payments or any other item which has been included in the Final Settlement Statement.

7.3.3.3. The Market Operator and the Market Participant shall make reasonable efforts to mutually settle the matter within (20) Business Days after the challenge is submitted to the Market Operator as per dispute resolution mechanism provided in Chapter 14.

7.3.4. EXTRAORDINARY SETTLEMENTS

7.3.4.1. The Market Operator shall issue an Extraordinary Settlement Statement for a month, where:

a) the dispute is settled between Market Participants according to the dispute resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement; or

b) the dispute is settled between a Market Participant and a Service Provider according to the dispute resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement.

7.3.4.2. The Extraordinary Settlement Statement shall supersede the issued Final Settlement Statement for such month.

7.3.4.3. The Market Operator shall calculate, for each Market Participant, the difference between the Extraordinary Settlement Statement and the Final Settlement Statement originally issued according to Sub-Section 7.3.1, and it will include the corresponding corrections in the Preliminary and Final Settlement Statement of the month immediately after the issuance of the Extraordinary Settlement Statement.

7.3.5. FAILURE OF THE MARKET SETTLEMENT SYSTEM

7.3.5.1. In case of an emergency or failure of the Market Settlement System, the Market Operator may issue an Estimated Settlement Statement and may modify the schedule for issuing Preliminary Settlement Statements or Final Settlement Statements, as the case may be. In such cases, the Market Operator shall inform all Market Participants and Service Providers the temporary procedural changes as soon as possible.

7.4. DEBIT AND CREDIT ADVICES

7.4.1. ADVICES TO MARKET PARTICIPANTS

7.4.1.1. Subject to Clause 7.4.3.2, the Market Operator, within (2) Business Days after issuance of the Final Settlement Statement, shall:

a) issue a Debit Advice in respect of the previous month to all Market Participants who are liable to pay an amount as per the Final Settlement. All payments shall be made within (2) Business Days upon receipt of the Debit Advice except where specifically provided otherwise by the Market Operator.

b) Issue a Credit Advice in respect of the previous month to all Market Participants who will receive a payment as per the Final Settlement Statement.

7.4.1.2. The Market Operator, in this process, shall act as an independent entity, without assuming any payment responsibility. Obligation of payment shall remain with the relevant Market Participants. For the avoidance of doubt, the Market Operator shall not be held liable for any kind of non-payment by any of the Market Participants.

7.4.2. DISAGREEMENTS WITH THE ADVICES

7.4.2.1. Each Market Participant which receives a Debit or Credit Advice, as per clause 7.4.1.1 above, shall pay the required amount, and shall be entitled to receive the amount, shown in the Final Settlement Statement, on the Payment Due Date, whether or not there is any dispute regarding the Amount Payable or the Amount Receivable.

7.4.2.2. The payment of any amount by the Market Participant to the Market Operator or by the Market Operator to the Market Participant, as the case may be, pursuant to clause 7.4.2.1 shall not prejudice the right of the Market Participant to seek resolution of the dispute pursuant to Chapter 14.

7.4.3. PAYMENTS BY ELECTRIC POWER SUPPLIERS INVOLVED IN LEGACY CONTRACTS-CPPA-G

7.4.3.1. Any amount chargeable or amount recoverable that arise due to the Settlement of Legacy Contracts-CPPA-G (Imbalances, Ancillary Services, Transmission Must Run and Reliability Must Run charges) shall be distributed among all EX-WAPDA DISCOs and KE, in their role as Suppliers of Last Resort, proportional to their Energy purchased up to the Cap set for the share of each EX-WAPDA DISCOs and KE in such Legacy Contracts-CPPA-G.

7.4.3.2. As per conditions specified in Clause 12.1.3.1, till the time the Ex-WAPDA DISCOs in their role as Suppliers of Last Resort have registered Bilateral Contracts other than Legacy Contracts-DISCOs and the Market Operator has been established as a separate legal entity, the amounts calculated pursuant to Clause 7.4.3.1 above shall be adjusted in the transfer pricing mechanism as set forth in the Special Purpose Agent code and shall be settled-accordingly. Further, all Competitive Suppliers or BPCs, as the case may be, shall pay the Market Operator Fee to the respective Distribution Licencee/Supplier of Last Resort under the Use of System Agreement as per provisions of the Eligibility Criteria (Electric Power Supplier Licences) Rules, 2023. The Distribution Licencee/Supplier of Last Resort shall pay the Market Operator Fee, along with the fee collected from the Competitive Suppliers or BPCs, in the following manner:

a) the Distribution Licencee/Supplier of Last Resort having Power Purchase Agency Agreement (PPAA) with CPPA-G, shall pay it through the transfer pricing mechanism as set forth in the Special Purpose Agent code.

b) Any Distribution Licencee/Supplier of Last Resort which does not have a Power Purchase Agency Agreement with CPPA-G shall directly pay it to the Market Operator.

Chapter 8. FIRM CAPACITY CERTIFICATION

8.1. PURPOSE

8.1.1.1. The purpose of this Chapter is to provide a procedure for administration of the certification process of Firm Capacity for Generators and Imports.

8.2. PROCEDURE FOR FIRM CAPACITY CERTIFICATION

8.2.1. CHARACTERISTICS OF FIRM CAPACITY CERTIFICATES

8.2.1.1. A Firm Capacity Certificate, issued by the Market Operator, shall have a nominal value of 0.1 MW, and may not be subdivided further.

8.2.1.2. Each Firm Capacity Certificate shall have a unique identification number which will be used to register and track Capacity transactions among Market Participants.

8.2.2. REQUIREMENT OF HAVING FIRM CAPACITY CERTIFICATES

8.2.2.1. A Generator interested to sell Capacity in the Market shall obtain Firm Capacity Certificates from the Market Operator for its Physical Assets, provided that a Generator may be represented by a Market Participant to obtain such certificates for its Physical Assets. In absence of such certification, the Firm Capacity allocated, to a Generator or a Market Participant who represents a Generator, shall be considered zero MW.

8.2.2.2. A Market Participant which has executed a Contract for Import of Energy or Capacity may also obtain Firm Capacity Certificates, subject to the conditions as laid down below.

8.2.2.3. A Market Participant may sell Capacity through registered Contracts up to the quantity included in its Firm Capacity Certificates.

8.3. ISSUANCE OF FIRM CAPACITY CERTIFICATES

8.3.1.1. The Market Operator shall make a CCOP for issuance of the Firm Capacity Certificates which shall include, inter alia, the following:

a) the data and information to be submitted by the parties to obtain Firm Capacity Certificates;

b) the information to be provided by the System Operator;

c) the procedure to be followed for issuance of the Firm Capacity Certificates;

d) the templates for "Application for Firm Capacity Certification";

e) the formulas to be used in calculation of the Firm Capacity Certificates for different type of technologies;

f) the procedure for changing Temporary Firm Capacity Certificates into permanent ones and the documents needed to certify the commissioning and actually installed capacity;

g) the procedure for review and amendment of the already issued Firm Capacity

Certificates.

8.3.1.2. The Market Operator shall issue the Firm Capacity Certificates, after registering them in the Firm Capacity Register. The number of Firm Capacity Certificates shall be calculated as the Firm Capacity in MW, certified during the certification process, multiplied by 10.

8.3.1.3. The Market Operator shall issue two types of Firm Capacity Certificates:

a) Temporary Firm Capacity Certificates

b) Permanent Firm Capacity Certificates (for initial three years termed as Initial Firm Capacity Certificates).

8.3.1.4. Temporary Firm Capacity Certificates are such certificates which may be issued at the request of a Market Participant or an Enrolled Person, for a new generation facility which fulfils any of the following requirements:

a) Generation License or concurrence has been issued by the Authority or a formal application has been submitted in this respect, if required;

b) documents proving the acquisition or rental of the land for construction of the Generation Plant as well as the requisite transmission lines;

c) authorizations and permits, issued by the relevant entities, for the construction of the Generation Plant;

d) EPC contracts, clearly stating the project commissioning date; or

e) any other relevant document.

8.3.1.5. The application for a Temporary Firm Capacity Certificate shall also contain a formal Capacity declaration signed by the authorized representative of the applicant. This declaration shall clearly state the Installed Capacity of the Generation Plant, expressed in electrical megawatt (MWe).

8.3.1.6. Any person owning a Temporary Firm Capacity Certificate may use them for promotional or commercial purposes and for ex-ante verification of Capacity Obligations of a Market Participant, however, such certificates may not be used to support Capacity transactions in a registered Contract.

8.3.1.7. The owner of a Temporary Firm Capacity Certificate (who shall either be enrolled as a Market Participant or as an Enrolled Person with the Market Operator) shall submit an application to the Market Operator for its cancellation and issuance of a Permanent Firm Capacity Certificate (also termed as the Initial Firm Capacity Certificate) not earlier than two months of the expected COD, provided that Permanent Firm Capacity Certificate shall not be issued for any Generation Plant which does not contribute to the Capacity Obligations of a Market Participant. However, Permanent Firm Capacity Certificates may be issued for such Generation Plants for participation in the Balancing Mechanisms for Energy and Capacity if it can provide all of the Ancillary Services except Black Start capability.

Explanation:

It is hereby clarified that a Generator which can provide all types of Ancillary Services, except Black Start Capability, may sell all of its Energy and/or Capacity through the Balancing Mechanisms as a merchant plant without registering any Bilateral Contract with the Market Operator.

8.3.1.8. The Permanent Firm Capacity Certificates shall be valid up to twenty (20) years or any other shorter period as decided by the Market Operator upon performing a review pursuant to this Code. Temporary Firm Capacity Certificates will have validity as decided by the Market Operator on a case to case basis and will expire on the COD of the concerned Generation Plant.

8.3.2. ISSUANCE OF FIRM CAPACITY CERTIFICATES

8.3.2.1. For Legacy Generators-CPPA-G or Legacy Generators-DISCOs, one month prior to the commencement of the CTBCM, the Market Operator shall determine the number of Firm Capacity Certificates, which shall be considered as Initial Firm Capacity Certificates, for each Generator having Generation Plants commissioned, or expected to be commissioned, before CMOD. The Initial Firm Capacity Certificates for Imports may be determined by the Market Operator after considering the particular features of the relevant Contract for Import.

8.3.2.2. For all Generation Plants owned by KE or Legacy Generators-KE, the KE shall provide the relevant information to the Market Operator and the Market Operator shall determine the number of Firm Capacity Certificates, which shall be considered as Initial Firm Capacity Certificates for each Generation Plant having Generation Plants commissioned or expected to be commissioned prior to integration of the KE into CTBCM as per integration plan approved by the Authority. Such certificates shall be issued to KE.

8.3.2.3. For Generators other than Legacy Generators-CPPA-G, Legacy Generators-DISCOs and Legacy Generators-KE, commissioned or expected to be commissioned before CMOD, or new Generation Plants, expected to be commissioned after CMOD, the Initial Firm Capacity Certificates may be issued upon request of the concerned Generator or its representative. For Legacy Generators-CPPA-G, Legacy Generators-DISCOs or Legacy Generator-KE, expected to be commissioned after CMOD, the Initial Firm Capacity Certificates may be issued to the EX-WAPDA DISCOs or KE, as the case may be, upon their request.

8.3.2.4. The Firm Capacity Certificates for Legacy Generators-CPPA-G shall be deemed issued by the Market Operator to the EX-WAPDA DISCOs in their role as Supplier of Last Resort as per the Commercial Allocation mechanism given in Sub-Section 18.2.10 of this Code and this information shall only be provided to the EX-WAPDA DISCOs and KE for demonstrating compliance with their Capacity Obligations.

8.3.2.5. After the CMOD, the Electric Power Traders or Electric Power Suppliers, who will procure Energy or Capacity through Import Contracts, the Initial Firm Capacity Certificates may be issued upon request of the concerned Electric Power Trader or Electric Power Supplier.

8.3.2.6. Any person interested to obtain the Initial Firm Capacity Certificates, may apply to the Market Operator, not earlier than two months before the expected COD of the Generation Plant. The applicant shall submit all the relevant information to the Market Operator required for such certification.

8.3.2.7. Where in the opinion of the Market Operator, the information submitted by the applicant for obtaining the Firm Capacity Certificates is false, fabricated or forged, especially where the said information may have material impact on the number of Firm Capacity Certificates to be issued, it may investigate the matter and if deemed appropriate, may take any action available under this Code or under the Applicable Law.

8.3.2.8. For a Generation Plant, the Initial Firm Capacity Certificates may be reduced or increased depending on its actual performance. This process may be initiated by the Market Operator on its own motion or upon the request of the concerned Market Participant.

8.3.2.9. For an Electric Power Trader or Electric Power Supplier with Import Contracts, the Initial Firm Capacity Certificates may be reduced depending on the information provided by the System Operator regarding the Energy or Capacity available for Import during critical periods of the system. This process may be initiated by the Market Operator upon information provided by the System Operator.

8.3.2.10. Two months prior to the expiry date of the Firm Capacity Certificates, the concerned Market Participant, may request the Market Operator to renew them or issue new certificates according to the procedure for issuance of the Initial Firm Capacity Certificates as set out above.

8.3.3. REGISTRATION OF THE ISSUED CERTIFICATES

8.3.3.1. The Market Operator shall organize and maintain a Firm Capacity Register, for Firm Capacity Certificates with the following information:

a) unique number for each Firm Capacity Certificate;

b) type of the certificate as per Clause 8.3.1.3;

c) name of the Market Participant or other person for which the Firm Capacity Certificate was issued;

d) name of the Market Participant currently owning the Firm Capacity Certificate;

e) identification code of the Generation Plant or Import Contract associated with the Firm Capacity Certificate;

f) status of Firm Capacity Certificate. The status of a Firm Capacity Certificate may be classified as:

f.1. **Available:** The Firm Capacity Certificate is valid and may be bought and sold to back any Capacity transaction;

f.2. **Blocked:** The Firm Capacity Certificate is valid but may not be used further for backing any Capacity transaction;

f.3. **Cancelled:** The Firm Capacity Certificate is no longer valid;

g) issuance and expiry date of each Firm Capacity Certificate.

8.3.3.2. Subject to Clause 8.3.2.4, the Firm Capacity Register shall be updated on regular basis and published on the MO Website.

8.4. <u>DETERMINATION OF INITIAL FIRM CAPACITY</u>

8.4.1. COMMISSIONED GENERATION PLANTS

8.4.1.1. The initial Firm Capacity, for a Dispatchable Generation Plant, commissioned prior to CMOD and has injected Energy into the Grid System, shall be determined by the Market Operator based on the Dependable Capacity and the Forced Outage Rate of the Generation Plant as per provisions of the CCOP prepared under Clause 8.3.1.1.

8.4.1.2. The initial Firm Capacity, for a Non-Dispatchable Generation Plant or Generation Plants whose dispatch is decided by the operator of the plant, commissioned prior to CMOD and has injected Energy into the Grid System, shall be determined as the average hourly Energy injected into the Grid System by the Generation Plant, during System Peak Hours, in the last three years as per provisions of the CCOP prepared under Clause 8.3.1.1.

8.4.1.3. For the application of Clause 8.4.1.2 above, where the Non-Dispatchable Generation Plants or Generation Plants whose dispatch is decided by the operator of the plant has been instructed by the System Operator or the Distribution Licensee, as the case may be, to reduce its production of Energy due to network or system constraints or due to provision of Ancillary Services or due to alleviation of Congestion, any Energy which was injected into the Grid System during the afore-referred period shall be excluded from the calculation of initial Firm Capacity.

8.4.1.4. The values excluded as per Clause 8.4.1.3 above, shall be replaced with the potential Energy that the Non-Dispatchable Generation Plant or Generation Plants whose dispatch is decided by the operator of the plant would have injected into the Grid System as forecasted by the System Operator.

8.4.1.5. The CCOP prepared under Clause 8.3.1.1 shall also include provisions for determination of the initial Firm Capacity for Dispatchable, Non-Dispatchable Generation Plants and Generation Plants whose dispatch is decided by the operator of the plant, describing the calculations to be performed to determine the initial Firm Capacity of such Generation Plants, as well as the necessary information and the institutions involved in providing such information.

8.4.1.6. The Initial Firm Capacity Certificates of commissioned Generation Plants may be issued with a validity up to twenty (20) years considering the remaining useful life of the Generation Plants.

8.4.2. NEW GENERATION PLANTS

8.4.2.1. The initial Firm Capacity of new Generation Plants, which will be commissioned after CMOD, , shall be calculated by the Market Operator based on the technology utilized by the Generation Plants, by multiplying the Dependable Capacity with the Equivalent Availability Factors, subject to demonstration of full availability during the System Peak Hours as provided in Table 1 below.

Table 1: Equivalent Availability Factors

Sr. No.	Generation Technology	Equivalent Availability Factor
1	**Dispatchable Technologies**	
1.1	Hydro with reservoir	Based on the feasibility study (Approved by WAPDA for projects developed by WAPDA and approved by panel of experts for other projects)
1.2	Thermal (either liquid fuels, gas, RLNG, or coal fired)	1-FOR
1.3	Bagasse	1-FOR
1.4	Solar Thermal	1-FOR
1.5	Nuclear	1-FOR
2	**Non-dispatchable Technologies**	
2.1	Hydro run of river	Based on the feasibility study Based on the feasibility study (Approved by WAPDA for projects developed by WAPDA and approved by panel of experts for other projects)
2.2	Thermal Generation Plants connected below transmission voltage	Based on relevant data
2.3	Wind	0.45
2.4	Solar PV	0.22

8.4.2.2. For Legacy Generators-CPPA-G to be commissioned after the CMOD, the buyer in the Legacy Contract-CPPA-G shall provide to the Market Operator, the information regarding the Dependable Capacity and the FOR of the Generation Plants. For other Generators, such information shall be provided by the relevant Generator to the Market Operator. Where the Initial Firm Capacity Certificates are to be issued, such information shall be provided by the Generator in accordance with the test performed by the System Operator under the Grid Code.

8.4.2.3. The Initial Firm Capacity Certificate of new Generation Plants may be issued with a validity up to twenty (20) years. The Market Operator must review the Firm Capacity Certificate of such Generation Plants within six months after completion of third year from COD.

8.4.3. NASCENT OR SPECIAL TECHNOLOGIES

8.4.3.1. The initial Firm Capacity of new Generation Plants, which will be commissioned after CMOD, and use nascent or special technologies, not included in Table 1, shall be determined on a case-to-case basis.

8.4.3.2. The Market Operator shall review the information submitted by the applicant and, if deemed appropriate, it may seek advice from reputable experts of such technologies.

8.4.3.3. The Initial Firm Capacity Certificate of new Generation Plants that use nascent or special technologies may be issued with a validity up to twenty (20) years. The Market Operator must review the Firm Capacity Certificate of such Generation Plants within six months after completion of third year from COD or any other shorter period as deemed appropriate by the Market Operator.

8.4.4. CONTRACTS FOR ENERGY OR CAPACITY IMPORTS

8.4.4.1. Import Contracts, signed in accordance with the applicable rules and regulations, which have provisions for firm Import shall be eligible to receive Firm Capacity Certificates. An Import Contract in order to qualify as firm Import shall:

a) stipulate that the Import comes from clearly identified group of Generation Plants, which are not connected to the system of the territory where the Generation Plant is located; or

b) in case of Imports from foreign countries, contain provisions which clearly specify that the buyer is entitled to receive the specified quantity of electric power on its demand, and that the seller is not entitled to restrict such Import for any reason, other than the unavailability of the interconnection line, and the laws applicable in the country of the seller do not require suspension of exporting Energy in case of shortages or energy deficits;

c) where the Import is backed by an international treaty, clearly specifying that the Import is firm and it will be respected even in cases of energy deficits or shortages in the country or region of the seller.

8.4.4.2. The Market Operator shall review the submitted Import Contract and shall determine if such Contract qualifies as firm Import or not.

8.4.4.3. In case the Import Contract qualifies as firm Import, the initial Firm Capacity for the Import Contract shall be equal to the Firm Capacity stated in the Import Contract, or if this value is not clearly stated in the Contract, the average forecasted Energy to be imported during the System Peak Hours.

8.5. REVIEW OF FIRM CAPACITY CERTIFICATES

8.5.1. REVIEW INITIATED BY THE MARKET OPERATOR

8.5.1.1. All Initial Firm Capacity Certificates issued to the Generation Plants or Imports shall be reviewed by the Market Operator within 6 months after completion of three years from the issuance date of such certificates or any other shorter period as deemed appropriate by the Market Operator.

8.5.1.2. After carrying out the first review of the Initial Firm Capacity Certificates as stipulated above, the Market Operator shall carry out review of the Firm Capacity Certificates every five (5) years. This review shall be performed within six (6) months after completion of the five years period.

8.5.1.3. Notwithstanding the provisions of review as stipulated in Clause 8.5.1.2 above, the Market Operator may review and cancel certain number of the Firm Capacity Certificates, in cases:

a) the actual availability of a Dispatchable Generation Plant is consistently below the values which were used to issue the Firm Capacity Certificates; or

b) the actual Energy produced by a Non-dispatchable Generation Plant or the Generation Plant whose dispatch is decided by its operator is consistently lower than the values which were used to issue the Firm Capacity Certificates; or

c) the contracted quantity of Energy and/or Capacity in an Import Contract is not available for dispatch, when required.

8.5.1.4. This review under Clause 8.5.1.3 may only be performed:

a) After the third year of the date of issuing the initial or renewed Firm Capacity Certificates; and

b) Not more than once within a period of five (5) years.

8.5.1.5. Where upon review of the Firm Capacity Certificates, it appears that the Firm Capacity of the Generation Plant is less than the number of Firm Capacity Certificates issued to a Market Participant, the Market Operator shall issue a notice to the concerned Market Participant requiring it to provide reasons why certain number of certificates may not be cancelled and, if requested, provide an opportunity of meeting. After receipt of reply to the notice and holding the meeting, if needed, the Market Operator shall decide whether to cancel certain number of Firm Capacity Certificates and inform the concerned Market Participant accordingly.

8.5.1.6. In case the Market Operator cancels certain number of Firm Capacity Certificates, it shall change the status of such certificates to "Cancelled". The number of certificates to be cancelled shall be calculated as the difference between the Firm Capacity included in the existing Firm Capacity Certificates and the new reduced value decided by the Market Operator multiplying it with a factor of ten (10). The status of a Cancelled Firm Capacity Certificate shall not be changed in any circumstances.

8.5.1.7. The CCOP prepared under Clause 8.3.1.1 shall include a criteria and procedure for measuring the actual performance of a Generator or Import Contract.

8.5.2. REVIEW OF FIRM CAPACITY CERTIFICATES REQUESTED BY A MARKET PARTICIPANT

8.5.2.1. A Generator or a Market Participant representing a Generator or having an Import Contract, may apply to the Market Operator for review of the Firm Capacity Certificates.

8.5.2.2. In case of Import Contracts, the application for review will only be processed where the Contract is explicitly associated with a Generation Plant. In such case, the Import Contract shall be considered as a Generation Plant.

8.5.2.3. The applicant may submit an application for review of the Firm Capacity Certificates by providing supporting information and documents, in the following cases:

a) after modification or major overhaul of the Generation Plant, which results in an increase in the Dependable Capacity; or

b) after overhaul of a Generation Plant which results in resolution of the cause of reduction of Firm Capacity Certificates; or

c) for any other reason, where the concerned Market Participant considers that the existing Firm Capacity Certificates do not reflect the actual Firm Capacity of the relevant Generation Plant. In this case, the Market Participant, along with other information, shall also submit information for last three years in which the Equivalent Availability Factor or the Energy actually generated, taking due consideration of those periods in which the

Generation Plant has been instructed to reduce Generation as per an instruction issued by the System Operator or the Distribution Network Operator, as the case may be, is above the input values considered to issue the existing Firm Capacity Certificates.

8.5.2.4. The application for review of the Firm Capacity Certificates of a Generation Plant may only be accepted if the Generation Plant:

a) is dispatched for, at least, 1,500 hours in each of the previous two years; and

b) has injected into the Grid System such quantity of Energy, in each of the previous two years, which is above the Generation Plant Dependable Capacity multiplied by 1,200 hours; or

c) in case of Dispatchable Generation Plants, has been tested by the System Operator to establish its dependable capacity and has issued a certificate in this regard.

8.5.2.5. Upon acceptance of the application, the Market Operator shall:

a) conduct analysis and carry out assessment as deemed appropriate, which may include:

a.1. comprehensive review of the submitted documents;

a.2. request the opinion of an independent expert on the cost of the applicant;

a.3. perform or require tests to be performed by third parties on the relevant Generation Plant on the cost of the applicant;

a.4. require a verification period, which may not last more than (180 days), during which the input values claimed by the applicant shall be actually demonstrated;

b) determine, after conducting analysis and carrying out assessments as stipulated above, the revised values which may be used to issue, if required, additional Firm Capacity Certificates for the relevant Generation Plant.

8.5.2.6. The above application for review of Firm Capacity Certificates shall only be accepted after three years of issuance of the existing Firm Capacity Certificate, provided that only one such application shall be processed within a period of five (5) years.

8.5.2.7. After acceptance of the application for review of the Firm Capacity Certificates, the newly issued Firm Capacity Certificates shall have the same validity date as of the previously issued Firm Capacity Certificates for the relevant Generation Plant.

8.5.3. CALCULATION OF NEW VALUES OF FIRM CAPACITY IN CASE OF REVIEW

8.5.3.1. The calculations for reduction or increase in the number of the Firm Capacity Certificates resulting from the review by the Market Operator on its own motion or on the application of the concerned Market Participant, shall be the same as followed to issue the Initial Firm Capacity Certificates for existing Generation Plants.

8.5.3.2. The data for a period of only last three years shall be considered for calculation of the Firm Capacity.

8.5.3.3. The CCOP prepared under Clause 8.3.1.1 shall include a criterion to accept or reject the application of the Market Participants and to determine the new values to be used to issue the revised Firm Capacity Certificates.

8.5.4. DISPUTE RESOLUTION

8.5.4.1. In case a Market Participant is aggrieved of a decision taken by the Market Operator regarding the Firm Capacity Certificates, it may file a dispute with the Market Operator according to the provisions of Chapter 14.

8.5.5. ACTIONS AFTER REVIEW OF FIRM CAPACITY CERTIFICATES

8.5.5.1. In case the number of Firm Capacity Certificates is increased after the review, the concerned Market Participant shall be entitled to register new Contracts or amend its existing registered Contracts using the additional Firm Capacity Certificates.

8.5.5.2. In case the number of Firm Capacity Certificates is reduced, and the remaining certificates are below the total Capacity sold by this Market Participant through registered Contracts, the concerned Market Participant shall execute new Contracts, amend the existing Contracts with the relevant Market Participants or procure the necessary additional Firm Capacity Certificates through Contracts with other Market Participants.

8.5.5.3. The aggregate Firm Capacity sold in the new or amended Contracts shall not exceed the quantum included in the total Firm Capacity Certificates issued. The new or amended Contracts executed by the concerned Market Participant shall be registered with the Market Operator, following the standard procedure as set out in this Code.

8.5.5.4. The CCOP prepared under Clause 8.3.1.1 shall include a procedure that shall be followed to check the appropriateness of the Contracts after review of the Firm Capacity Certificates.

Chapter 9. BALANCING MECHANISM FOR CAPACITY

9.1. INTRODUCTION

9.1.1. PURPOSE

9.1.1.1. The purpose of the Balancing Mechanism for Capacity is to facilitate Market Participants to comply with their Capacity Obligations. In the Balancing Mechanism for Capacity, a Market Participant purchases Capacity in order to comply with its Capacity Obligations from other Market Participants which have Capacity in excess of their obligations.

9.1.1.2. The Capacity Imbalances for each Market Participant shall be determined, through the Balancing Mechanism for Capacity, as the difference between:

a) the Capacity taken from the Grid System and the Credited Capacity to such Market Participant pursuant to a registered Contract or its own Generation Plants;

b) the Guaranteed Capacity sold by a Market Participant through a registered Contract and the Capacity actually provided by the relevant Generation Plants.

9.1.1.3. The results of the Balancing Mechanism for Capacity shall also be used to verify ex-post compliance with the Capacity Obligations of each Market Participant.

9.1.2. BALANCING PERIOD

9.1.2.1. The Market Operator shall calculate the Capacity Imbalances on yearly basis (the Capacity Balancing Period), on the basis of certain number of hours in which the system is stressed "the Critical Hours".

9.1.3. SELLERS AND BUYERS IN THE BALANCING MECHANISM FOR CAPACITY

9.1.3.1. The following Market Participants may sell Capacity in the Balancing Mechanism for Capacity:

a) a Generator which has not sold all of its Available Capacity, through registered Contracts, to other Market Participants;

b) a Market Participant which has excess Capacity, purchased through registered Contracts, than its requirement;

9.1.3.2. The following Market Participants may purchase in the Balancing Mechanism for Capacity:

a) a Market Participant which has sold Guaranteed Capacity, as provided in Clause 3.2.1.5, to another Market Participant, however, the provided Capacity is less than the Guaranteed Capacity;

b) a Market Participant which has taken Capacity from the Grid System in excess of its Credited Capacity.

9.2. PROCEDURE FOR ADMINISTRATION OF THE BALANCING MECHANISM FOR CAPACITY

9.2.1. STEP 1: IDENTIFICATION OF CRITICAL HOURS

9.2.1.1. For calculation of the Capacity Imbalances of a Market Participant, the Market Operator shall consider the Capacity actually provided by a Generator and the Capacity actually taken by a Market Participant during the "Critical Hours". For the purposes of this chapter, the Critical Hours are defined as such hours of the previous year when the power system was under maximum stress.

9.2.1.2. Within eighteen (18) months of the CMOD, the System Operator shall, in collaboration with the Market Operator, make a CCOP for determining the Critical Hours, of the previous year, during which the power system was under maximum stress. The said CCOP shall include:

a) the characteristics of the Demand;

b) the production of Energy by certain technologies, which, due to their characteristics, are not able to fully control their Energy injection into the Grid System;

c) the specific characteristics of the constraints of the hydro Generation;

d) the Generation Units maintenance plans;

e) fuel constraints, operational constraints and transmission reliability considerations; and

f) the minimum reserve requirements of the power system.

9.2.1.3. Until the System Operator develops the CCOP as provided in Clause 9.2.1.2 above, the Critical Hours shall be determined by the System Operator as:

a) the fifty (50) hours in which the total Generation and an estimation of the Demand, which has been disconnected upon instructions issued by the System Operator or the DISCO due to generation or network constraints, as the case may be, is higher than all other hours; and

b) not more than five (5) hours of the same day shall be included in the Critical Hours.

9.2.1.4. The Critical Hours shall be determined by the System Operator within fifteen (15) Business Days immediately after the end of each Fiscal Year and provide such information to the Market Operator.

9.2.2. STEP 2: DETERMINATION OF THE CAPACITY PROVIDED BY GENERATORS

9.2.2.1. For the Balancing Mechanism for Capacity, the Capacity provided by each Generation Plant (expressed in MW-year) shall be equal to the average Capacity provided by such Generator to the Grid System during the Critical Hours.

9.2.2.2. The System Operator shall determine, for each hour included in the Critical Hours, the Capacity provided by a Generation Plant, after taking due consideration of the type of such unit as under:

a) for an ARE Generation Plant without storage, whose production of Energy is dependent on the availability of the primary energy resource, the Capacity provided shall be equal to:

a.1. the Energy injected into the Grid System by such Generation Plant during the hour; plus a.2. such quantity of Energy that such Generation Plant would have injected into the Grid System during the hour, but could not be injected due to grid failure or curtailment instructed by the System Operator or the DISCO for disconnection or reduction of Energy generation, on account of Congestion or provision of Ancillary Services, which shall equal to the Energy forecasted by the System Operator for the relevant hour;

b) for Non-Energy Limited Generation Plants, the Capacity provided shall be equal to the Available Capacity of the Generation Plants during the hour, as informed by the concerned Market Participant to the System Operator according to the provisions of the Grid Code such as thermal power plants;

c) For Energy Limited Generation Plants as defined below, the Capacity provided during the hour shall be calculated as set forth below depending on the quantity of primary energy stored;

c.1. In case the primary energy stored during the relevant hour would be enough for operating the Generation Plant at its Installed Capacity for at least ninety-six (96 hours), the Generation Plant shall be considered as a Non-Energy Limited Generation Plant and the Capacity provided shall be calculated as per paragraph b) above such as Hydro plant with large reservoirs as well as wind and solar having similar storage capacity;

c.2. In case the primary energy stored at the relevant hour would not be enough for operating the Generation Plant at its Installed Capacity for at least ninety-six (96 hours), the Capacity provided shall be calculated as per Paragraph 9.2.2.2.a) above such as run of river hydro plants or wind and solar plants with very limited storage capacity;

d) for Imports, the Capacity provided shall be equal to the Capacity determined by the System Operator taking due consideration of the nature of the Import Contract, which shall not be lower than the actual Import during the corresponding hour.

9.2.2.3. Within eighteen (18) months after the approval of this Code, the System Operator shall, in collaboration with the Market Operator, make a CCOP describing the detailed methodology for implementing the calculations indicated in Clause 9.2.2.2. Such methodology shall take due consideration of:

a) Generation Plans maintenance plans and eventual modification of such plans, instructed by the System Operator;

b) Availability Declarations of each Generation Plant, as the case may be, and eventual changes to such declarations informed by the Generators or other Market Participants during real time operations;

c) the results of tests performed or instructed by the System Operator to be performed to verify the Availability Declarations submitted by the Generators or other Market Participants, including compliance with instructions of start-up, synchronizing and production of Energy;

d) the results of audits, performed by the System Operator, aimed to verify the appropriateness of the Availability Declarations submitted by the Generators or other Market Participants.

9.2.2.4. The Capacity provided by each Generation Plant, for each hour included in the Critical Hours, shall be determined by the System Operator within fifteen (15) Business Days immediately after the end of each Fiscal Year and provide such information to the Market Operator.

9.2.3. Step 3: Capacity Credited to Market Participants

9.2.3.1. The Market Operator shall credit the Capacity provided by each Generation Plant, for each of the hours included in the Critical Hours, to the relevant Market Participants by considering the information contained in the Contract Register as well as the Firm Capacity Register.

9.2.3.2. The crediting of the Capacity shall be done in the following way:

a) where a Generator which owns the Generation Plant, or an Electric Power Trader representing the Generator, has not registered any Contract involving "Non-Guaranteed Capacity", the Capacity provided by the relevant Generation Plant, during each of the hours included in the Critical Hours, shall be credited proportionally to the owners of the Firm Capacity Certificates of such Generation Plant, during the day to which the corresponding hour belongs;

b) where the Generator which owns the Generation Plant or Electric Power Trader representing the Generator has registered a Contract, in which the Generation Plant is involved in a transaction of "Guaranteed Capacity", for each hour included in the Critical Hours:

b.1. the Capacity stated in the Contract shall be fully credited to the Market Participant which is the buyer in the Contract; and

b.2. the Capacity provided by the Generation Plant shall be fully credited to the Market Participant which is the seller in the Contract;

c) where the Generator which owns the Generation Plant or Electric Power Trader representing the Generator has registered Contracts, in which the Generation Plant is involved, partially in transactions of "Guaranteed Capacity" and partially in transactions of "Non-Guaranteed Capacity", the portion involved in "Guaranteed Capacity" shall be assigned as indicated in paragraph b) and the remaining part shall be assigned as provided in paragraph 9.2.3.2.a) above;

d) while performing the calculations as per Clause 9.2.3.2.b) and Clause 9.2.3.2.c) above, all the Contracts till the last buyer of the Capacity shall be considered.

9.2.3.3. Once the Market Operator has credited the Capacity provided by all Generation Plants to the corresponding Market Participants, in accordance with Clause 9.2.3.2 above, it shall determine the Credited Capacity of each Market Participant as the average of the Credited Capacity at each hour included in the Critical Hours:

$$ACC_{i,y}[MW] = \frac{\sum_{h \in CH} CC_{i,h}}{50\ hours}$$

Where:

$ACC_{i,y}$ is the Credited Capacity to Market Participant *"i"*, for the Fiscal Year *"y"*, in MW;

$CC_{i,h}$ is the Credited Capacity to Market Participant *"i"*, in hour *"h"*, calculated pursuant Clause 9.2.3.2, in MW;

$\sum_{h \in CH}$ means the 50 hours which have been defined as Critical Hours, for the Fiscal Year *"y"*.

9.2.4. STEP 4: CAPACITY REQUIREMENTS OF MARKET PARTICIPANTS

9.2.4.1. For the Balancing Mechanism for Capacity, all Market Participants which supply to Consumers, BPCs which are enrolled as Market Participants and, if applicable, Firm Exports, shall be required to procure Capacity, as determined below. Further, Generators or Electric Power Traders representing Generators which have sold Guaranteed Capacity to Market Participants, shall be required to provide Capacity which was sold through the registered Contracts. This requirement to procure Capacity is termed as the Capacity Requirement for the Market Participants.

9.2.4.2. The Capacity Requirement for the Market Participants as referred to in Clause 9.2.4.1 above shall be calculated by the Market Operator as under:

a) in the case of a BPC, which is a Market Participant, the Capacity Requirement shall be equal to the average Energy withdrawn, during the Critical Hours, calculated pursuant to Clause 5.4.5.1, multiplied by a Reserve Margin:

$$ACR_{i,y}[MW] = \left[\frac{\sum_{h\in CH}(ES_{i,h})}{50\ hours}\right](1 + RM)$$

Where:

$ACR_{i,y}$ is the Capacity Requirement of BPC "i", for the Fiscal Year "y", in MW;

$ES_{i,h}$ is the Energy withdrawn by BPC "i", in hour "h", calculated pursuant to Clause 5.4.5.1, in MWh;

$EC_{MP_{i,j,h}}$ is the Energy supplied by the Competitive Supplier "j" to the BPC "i", in hour "h", as per the information contained in the Contract Register of the Market Operator;

$\sum_{h\in CH}$ means the 50 hours which have been defined as Critical Hours, for the Fiscal Year "y";

RM is the applicable Reserve Margin.

b) in the case of Competitive Electric Power Suppliers, its Capacity Requirement shall be equal to the average Energy supplied by the Electric Power Supplier, during the Critical Hours, calculated pursuant to Clause 5.4.5.1, multiplied by a Reserve Margin. The Energy supplied for each particular hour shall be the addition of the Energy supplied to all the BPCs served by the Competitive Supplier who are not Market Participants during the relevant hour:

$$ACR_{j,y}[MW] = \frac{\sum_{h\in CH}\left(\sum_{\forall BPC_{i,j}} ES_{i,j,h}\right)}{50\ hours}\ (1 + RM)$$

Where:

$ACR_{j,y}$ is the Capacity Requirement of the Competitive Supplier "j", for the Fiscal Year "y", in MW;

$ES_{i,j,h}$ is the total Energy supplied by the Competitive Supplier "j", to BPC "i" which is not a Market Participant, in hour "h" , calculated pursuant Clause 5.4.5.1;

$\sum_{\forall BPC_{i,j}}$ means the sum over all BPCs "i" who are not Market Participants and supplied by the Competitive Supplier "j";

$\sum_{h \in CH}$ means the 50 hours which have been defined as Critical Hours, for the Fiscal Year "y";

RM is the applicable Reserve Margin.

c) in the case of Suppliers of Last Resort, the Capacity Requirement shall be equal to the average Energy supplied by the Supplier of Last Resort, during the Critical Hours, calculated pursuant to Clause 5.4.5.1:

$$ACR_{k,y}[MW] = \frac{\sum_{h \in CH}(ES_{k,h})}{50\ hours}\ (1 + RM)$$

Where:

$ACR_{k,y}$ is the Capacity Requirement of the Supplier of Last Resort "k", for the Fiscal Year "y", in MW;

$Act\_ES_{k,h}$ is the total Energy supplied by Supplier of Last Resort "k", in hour "h", calculated pursuant to Clause 5.4.5.1, in MWh;

$\sum_{h \in CH}$ means the 50 hours which have been defined as Critical Hours, for the Fiscal Year "y";

RM is the Reserve Margin.

d) in the case of Electric Power Traders which have Contracts for Firm Export, the Capacity Requirement shall be equal to Energy Exported by the Electric Power Trader during the Critical Hours calculated pursuant to Clause 5.4.5.1, multiplied by a Reserve Margin:

$$ACR_{k,y}[MW] = \frac{\sum_{h \in CH}\left(\sum_{\forall EXP_{x,k}} ES_{k,x,h}\right)}{50\ hours}\ (1 + RM)$$

Where:

$ACR_{k,y}$ is the Capacity Requirement of the Electric Power Trader with Export Contracts "k", for the Fiscal Year "y", in MW;

$ES_{k,x,h}$ is the total Energy exported by the Electric Power Trader "k" through Firm Export Contracts, to system "x", in hour "h", calculated pursuant Clause 5.4.5.1, in MWh;

$\sum_{\forall EXP_{x,k}}$ means the sum over all exports "x" which are carried out by the Electric Power Trader "k";

$\sum_{h \in CH}$ means the 50 hours which have been defined as Critical Hours, for the Fiscal Year "y";

RM is the applicable Reserve Margin.

e) in the case of Market Participants which have executed Contracts, involving the sale of Guaranteed Capacity to other Market Participants, the Capacity Requirement shall be equal to the Capacity sold through such Contracts, without considering losses or Reserve Margin.

9.2.4.3. The Reserve Margin is the minimum amount of reserve that the system requires to satisfy the reliability criteria as provided in the Grid Code, and it will be expressed as percentage. The value of the Reserve Margin shall be determined, periodically, by the System Operator pursuant to the provisions of the Grid Code. The first value shall be determined by the System Operator within six (6) months of the CMOD and inform the same to the Market Operator. Till such time the System Operator determines this value and inform the Market Operator accordingly, the Reserve Margin shall be equal to (10.0%).

9.2.5. STEP 5: CAPACITY BALANCES OF EACH MARKET PARTICIPANT

9.2.5.1. The Market Operator shall calculate the Capacity Balance of each Market Participant as the difference between the Credited Capacity and the Capacity Requirement of each Market Participant as under:

$$CB_{i,y} = ACC_{i,y} - \ ACR_{i,y}$$

Where:

CBi_{y}	is the Capacity Balance of Market Participant "i", for the year "y", which will be used for determining its participation in the Balancing Mechanism for Capacity, in MW;
$ACC_{i,y}$	is the Credited Capacity to Market Participant "i", for the year "y", calculated pursuant to Clause 9.2.3.3, in MW;
$ACR_{i,y}$	is the Capacity Requirement of the Market Participant "i", for the year "y", calculated pursuant to Clause 9.2.4.2, in MW.

9.2.6. STEP 6: DETERMINATION OF THE EFFICIENT RESERVE AND THE REFERENCE TECHNOLOGY

9.2.6.1. Every year, while developing the IGCEP, as stipulated in the Grid Code, the System Operator shall determine:

a) the efficient level of reserves required for the system; and

b) the unitary price for the Capacity expressed in PKR/MW-year, which will be used for the Balancing Mechanism for Capacity.

9.2.6.2. The efficient level of reserves is the Capacity that is required to be installed in the system above the peak load, on long term basis, in order to minimize the total system costs. The total system costs shall include:

a) the investment costs;

b) the operational costs;

c) the cost of the energy not supplied.

9.2.6.3. The efficient level of reserves shall be calculated as the total Installed Capacity divided by the peak load of the system included in the end period of the IGCEP, expressed in percent:

$$RE = \frac{\sum_{y}\left(\frac{TIC_y}{PL_y} - 1\right) * 100}{n}$$

Where:

RE	is the efficient level of reserves expressed in percentage;
TIC_y	is the total Installed Capacity in year "y", which minimizes the total costs of the system, calculated by the System Operator in the IGCEP;
PL_y	is the peak load of the system in year "y", including transmission losses, which has been used by the System Operator in preparation of the IGCEP;
n	is the total number of years used in the determination of the efficient reserve.

9.2.6.4. Within twelve (12) months of the CMOD, the System Operator shall determine this value. Till such time the System Operator determines the efficient level of reserve, the value provided in Clause 18.2.8 shall apply.

9.2.6.5. The unitary cost of the Capacity is the investment cost of the most economic Generation Unit, capable to provide 1 MW of Firm Capacity during the Critical Hours.

9.2.6.6. Within twelve months of CMOD, the System Operator shall determine the unitary cost of the Capacity, when developing the IGCEP, considering different generation technologies, and calculating for each of them, the levelized investment cost and the revenues that this project would obtain during the "Critical Hours" if it had been operating in the market. Only technologies capable to provide controllable Capacity shall be considered.

9.2.6.7. The estimated investment costs, for each technology shall include:

a) the costs of the project may include, among other inputs:

a.1. equipment costs;

a.2. site acquisition costs (land);

a.3. engineering, procurement, project management and construction costs;

a.4. legal costs;

a.5. interconnection costs of the transmission system;

a.6. construction costs and interconnection of fuel pipelines, if applicable; and

a.7. mobilization and contingent costs;

b) estimated financial costs of the project;

c) the assumed economic operational life of the project, considering the salvage value after that operational life;

d) an appropriate discount rate, which shall be determined by the System Operator, properly documented in the reports attached with the IGCEP.

9.2.6.8. The estimated revenues for each technology shall be calculated by the System Operator, as the difference between the estimated System Marginal Prices at the expected Critical Hours and the variable cost of the technologies evaluated.

9.2.6.9. The levelized fixed cost of the technologies evaluated shall be calculated as:

$$LFT = LIC - RevMarket$$

Where:

- *LFT* is the levelized fixed cost of the technology being evaluated;
- *LIC* is the levelized investment cost; and
- *RevMarket* are the simulated revenues that this technology would have obtained in the CTBCM during the 50 Critical Hours.

9.2.6.10. The Reference Technology will be the technology which minimizes their levelized fixed costs, determined pursuant to Clause 9.2.6.9. The unitary cost of the Capacity shall be equal to the levelized investment cost of the reference technology.

9.2.6.11. The System Operator shall provide to the Market Operator, the detailed methodology which was utilized for determining the efficient reserve and the unitary cost of the Capacity. Till such time this methodology is developed by the System Operator, the unitary cost of the Capacity shall be determined as per Clause 18.2.7.1 and the efficient reserve level shall be determined as per Clause 18.2.8.1 and Clause 9.2.6.12 shall not apply.

9.2.6.12. The Authority shall approve the values of the efficient reserve and the unitary cost of the Capacity when approving the IGCEP. The approved values will be notified by the Authority to the Market Operator. These values will remain valid until the Authority notifies to the Market Operator new values.

9.2.7. Step 7: Determination of the Capacity Price for the BMC

9.2.7.1. The Market Operator shall determine the Capacity price to be used in the Balancing Mechanism for Capacity through two curves: A supply curve and a demand curve, as demonstrated in Figure 1 below.

a) The supply curve represents the Capacity "offered" by the Market Participants. It shall be calculated as the sum of the Capacity Balances of all Market Participants which have a positive Capacity Balance (Capacity surplus). This Capacity is considered to be offered in the Balancing Mechanism for Capacity, as a price taker.

b) The demand curve: The demand curve will have two sections. The mandatory part and the efficient part.

9.2.7.2. The "mandatory" part will start at point A, which corresponds to a Capacity of zero and a price equal to two times the levelized fixed costs of the Reference Technology, and extends horizontally to point B, which corresponds to the sum of the Capacity Balances of all Market Participants with a negative Capacity Balance value (Capacity deficit).

9.2.7.3. The "efficient" section will start at point B and it will extend to point C. This point will be determined by the intersection of the levelized fixed cost of the reference technology, and the "efficient" demand level calculated as:

$$EDL_y = \sum_{\forall i \in neg} CB_{i,y} * \frac{1+RE}{1+RM}$$

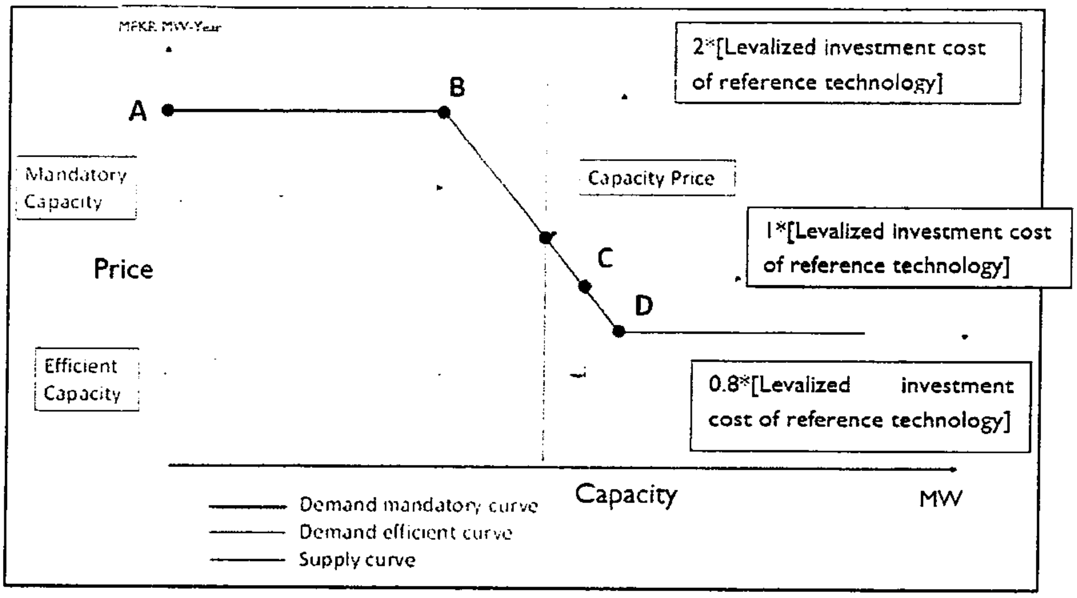
Where:

- *EDL* is the efficient demand level;
- $CB_{i,y}$ is the total amount of Capacity required by the Market Participants "i" which has a negative value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1;

- *RE* is the efficient level of reserve calculated as per Clause 9.2.6.3:
- *RM* is the Reserve Margin.

9.2.7.4. The "efficient" section of the demand curve will extend, with the same slope, up to point D, which corresponds to 80% of the levelized fixed costs of the reference technology. The Capacity prices will be capped at such level.

Figure 1: Demand and Supply Curves for the Capacity Balancing Mechanism



9.2.7.5. The Capacity price, which will be used in the Capacity Balancing Mechanism will be the intersection of the demand and supply curves.

9.2.8. STEP 8: DETERMINATION OF THE AMOUNTS SOLD AND PURCHASED BY EACH MARKET PARTICIPANT

9.2.8.1. The amount of Capacity sold and purchased by each Market Participant in BMC shall be calculated according to the procedure given below, depending on the crossing point between the supply and demand curves, determined pursuant to Sub-Section 9.2.7:

a) If the supply curve crosses the demand curve in the segment delimited by the points A and B of Figure 1, it implies that the sum of the Capacity Balances of Market Participants with positive balances (Capacity Surplus) is not enough for covering the sum of Market Participants with negative balances. In this case:

a.1. the Market Participants with positive balances will sell all their surplus of Capacity:

$$CS_{i,y} = CB_{i,y}$$

Where:

$CS_{i,y}$ is the total amount of Capacity sold by the Market Participant "i" with positive value of Capacity Balance, in year "y";

$CB_{i,y}$ is the total amount of Capacity offered by the Market Participant "i", in year "y", which has a positive value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1.

a.2. the Market Participants with negative balances will purchase only a share of their Capacity Requirement, on a proportional basis:

$$CP_{j,y} = \frac{CB_{j,y}}{\sum_j CB_{j,y}} * \sum_i CB_{i,y}$$

Where:

$CP_{j,y}$ is the total amount of Capacity purchased by the Market Participant "j" with negative value of Capacity Balance, in year "y";

$CB_{j,y}$ is the total amount of Capacity Requirement by the Market Participant "j", in year "y", which has a negative value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1;

$CB_{i,y}$ is the total amount of Capacity offered by the Market Participant "i", in year "y", which has a positive value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1;

$\sum_j$ means the sum of all Market Participants with negative Capacity Balance;

$\sum_i$ means the sum of all Market Participants with positive Capacity Balance.

b) If the supply curve crosses the demand curve to the right of B of Figure 1, it implies that the sum of the Capacity balances of Market Participants with positive balances (Capacity Surplus) is sufficient or in excess of the requirements of all Market Participants with negative balances. In this case:

b.1. the Market Participants with negative balances will purchase all their deficit of Capacity:

$$CP_{j,y} = -CB_{j,y}$$

Where:

$CP_{j,y}$ is the total amount of Capacity purchased by the Market Participant "j" with negative value of Capacity Balance, in year "y";

$CB_{i,y}$ is the total amount of Capacity required by the Market Participant "j", in year "y", which has a negative value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1.

b.2. the Market Participants with positive balances will sell a portion of their Capacity surplus, on a proportional basis:

$$CS_{i,y} = -\frac{CB_{i,y}}{\sum_i CB_{i,y}} * \sum_j CB_{j,y}$$

Where:

$CS_{i,y}$	is the total amount of Capacity sold by the Market Participant "i" with positive value of Capacity Balance, in year "y";
CBi,y	is the total amount of Capacity required by the Market Participant "j", in year "y", which has a negative value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1;
$CB_{i,y}$	is the total amount of Capacity offered by the Market Participant "i", in year "y", which has a positive value of the Capacity Balance, calculated pursuant to Clause 9.2.5.1;
$\sum_j$	means the sum of all Market Participants with negative Capacity Balance;
$\sum_i$	means the sum of all Market Participants with positive Capacity Balance.

9.3. DETERMINATION OF THE PRELIMINARY RECEIVABLE AND PAYABLE AMOUNTS

9.3.1. CALCULATION OF THE PRELIMINARY RECEIVABLE / PAYABLE AMOUNTS

9.3.1.1. Within forty five (45) Business Days immediately after the end of each Fiscal Year, the Market Operator shall preliminarily determine the Amounts Payable and Amounts Receivable by each Market Participant as under:

$$AR_{i,y}(PKR) = CS_{i,y}(MW) * Cap\_price_y[PKR/MW]$$

$$AP_{j,y}(PKR) = CP_{j,y}(MW) * Cap\_price_y[PKR/MW]$$

Where:

- $AR_{i,y}$ is the Amount Receivable by a Market Participant "i" for the settlement year "y", for the Capacity sold in the Balancing Mechanism for Energy;
- $AP_{j,y}$ is the Amount Payable by Market Participant "j" for the settlement year "y", for the Capacity purchased in the Balancing Mechanism for Energy;
- $CP_{i,y}$ is the Capacity purchased by a Market Participant "i" in the settlement year "y" calculated pursuant to Clause 9.2.8.1;
- $CS_{j,y}$ is the Capacity sold by a Market Participant "j" in the settlement year "y" calculated pursuant to Clause 9.2.8.1;
- Cap_price_y is the unitary price of Capacity, corresponding to the Fiscal Year "y", calculated pursuant to Clause 9.2.7.5.

9.3.1.2. The Amounts Payable shall be recovered from the relevant Market Participants in six (6) equal monthly instalments and the Amounts Receivable by the Market Participants shall be paid to such Market Participants in same manner.

9.4. APPLICABLE TAXES

9.4.1. APPLICABILITY OF TAXES

9.4.1.1. All Settlements calculated by the Market Operator pursuant to this Chapter shall be subject to the applicable taxes as per Applicable Law.

9.5. INTIMATION TO THE MARKET PARTICIPANTS

9.5.1.1. The Market Operator shall intimate to each Market Participant:

a) The preliminary values of the Amounts Payable or the Amounts Receivable, as the case may be, of all Market Participants, in the Balancing Mechanism for Capacity;

b) The date for determination of the final Amounts Payable or the Amounts Receivable, as the case may be, of all Market Participants, in the Balancing Mechanism for Capacity;

c) the amount of Advance Instalment for an amount not lower than two (2) monthly instalments of the value of the notified Amounts Payable, and the last date for the provision of Advance Instalment; and

d) the amount of Advance Instalments to be submitted for the future instalments; and

e) A clear warning that failure to provide the necessary Advance Instalment on time will automatically exclude such Market Participant from participation in the Balancing Mechanism for Capacity and will also result in non-compliance with its Capacity Obligations and will be considered as an Event of Default.

9.5.1.2. In case a Market Participant considers that an error or discrepancy exists either in the determination of the Amounts Payable or Amounts Receivable intimated by the Market Operator, or in the calculations performed, or in the parameters used to perform such calculations, it shall submit to the Market Operator a written Review Request within ten (10) Business Days of receipt of the intimation as provided in Clause 9.5.1.1.

9.5.1.3. The Review Request shall clearly state the item or items claimed, the reasons for the claim, the amount claimed, and shall be accompanied with all the supporting documents.

9.5.1.4. After receipt of the Review Request, the Market Operator shall review the request and decide whether there is any error or discrepancy in the calculations it has made and if required, it may hold a meeting with the relevant Market Participant to settle the matter. If the Market Operator does not agree with the Review Request, it shall intimate the same to the relevant Market Participants along with reasons thereof.

9.5.1.5. Where the Market Operator, after reviewing the calculations that it has performed, finds that there is an error or discrepancy as claimed by the relevant Market Participant, it shall rectify the error and shall issue new intimations to all Market Participants, informing at least:

a) the corrections made and the new values for the preliminary Amounts Payable and Amounts Receivable;

b) the new values for the Advance Instalment to be provided; and

c) if it is considered appropriate, a new date for the final implementation of the Balancing Mechanism for Capacity.

9.6. EXECUTION OF THE BALANCING MECHANISM FOR CAPACITY

9.6.1. VERIFICATION OF THE ADVANCE INSTALMENTS

9.6.1.1. Prior to final implementation of the Balancing Mechanism for Capacity, the Market Operator shall examine and verify the amount of the Advance Instalments provided by each Market Participant.

9.6.1.2. In case a Market Participant fails to provide the Advance Instalment, the concerned Market Participant shall be excluded from participation in the Balancing Mechanism for Capacity and this failure to provide the Advance Instalment shall constitute an Event of Default and shall be dealt in accordance with Chapter 16 of this Code.

9.6.1.3. Where a Market Participant has provided an Advance Instalment for an amount less than the requisite amount, the concerned Market Participant may be allowed, on case to case basis, to participate in the Balancing Mechanism for Capacity, limited up to the amount for which it has provided the Advance Instalment. The failure to provide the requisite Advance Instalment in full shall constitute an Event of Default and shall be dealt with according to Chapter 16 of this Code.

9.6.1.4. In case of insufficient Capacity as per Clause 9.2.8.1.a), the Capacity allocated to a Market Participant, which has been excluded from the BMC as per Clause 9.6.1.2, or whose participation has been limited as per Clause 9.6.1.3 ,will be redistributed among the other Market Participants with negative Capacity Balances on pro-rata basis.

9.6.1.5. In case of sufficient Capacity as per Clause 9.2.8.1.b), the Capacity sold by all Market Participants shall be recalculated, reducing it on pro-rata basis.

9.6.2. EXECUTION OF THE BALANCING MECHANISM FOR CAPACITY

9.6.2.1. After fulfilling the above referred requirements, the Market Operator shall determine the final Amounts Payable and Amounts Receivable by all Market Participants, which will be used in the yearly Settlement Statements, as provided in Chapter 11 and make payments accordingly.

9.6.2.2. The methodology and procedures to be used to determine the final Amounts Payable and Amounts Receivable of each Market Participant shall be the same as the procedure set out in Sub-Section 9.3.1, except that:

a) the Capacity purchased by the Market Participants which have been excluded from participation in the Balancing Mechanism for Capacity as per Clause 9.6.1.2 shall be set at zero (0.0); and

b) the Capacity purchased by the Market Participants, whose participation has been limited under Clause 9.6.1.3, will be capped to such limit.

9.6.2.3. Where any amount is recovered from a Market Participant who was excluded from participation in the Balancing Mechanism for Capacity as per Clause 9.6.1.2 or whose participation was limited under Clause 9.6.1.3, the same shall be distributed among the Market Participants having positive Capacity Balances on pro-rata basis and the Market Operator shall re-evaluate the compliance with Capacity Obligations of such Market Participants as per Sub-Section 9.7.1.

9.6.3. PUBLICATIONS OF BMC RESULTS

9.6.3.1. The Market Operator shall publish, on the MO Website, the following information:

a) the 50 Critical Hours that were used to determine the Capacity Balances;

b) the Capacity Requirement of each Market Participant;

c) the Credited Capacity of each Market Participant;

d) the resulting Capacity Balance of each Market Participant;

e) the Capacity price for the corresponding settlement year, along with a report justifying the calculations performed and the parameters used in such calculations;

f) the Amounts Payable and the Amounts Receivable of each Market Participant;

g) the list of Market Participants which have been excluded from participation in the Balancing Mechanism for Capacity due to their failure to provide the requisite Advance Instalment; and

h) any other information the Market Operator deems appropriate.

9.6.3.2. Following information shall be made available to each relevant Market Participant:

a) the details of the Capacity Requirement at each of the Critical Hours, and the metering data that was used for determining the Capacity Requirement of such Market Participant;

b) the details of the Credited Capacity at each of the Critical Hours, and the availability of Generation Plants or the actual Generation, as the case may be, communicated by the System Operator that was used for determining the Credited Capacity of such Market Participant.

9.7. ACTIONS AFTER EXECUTION OF THE BMC

9.7.1. VERIFICATION OF COMPLIANCE WITH THE EX-POST CAPACITY OBLIGATIONS

9.7.1.1. After closing of the Balancing Mechanism for Capacity in a year, the Market Operator shall verify compliance of all Market Participants with the ex-post Capacity Obligations.

9.7.1.2. Non-compliance with the Capacity Obligations may arise due to any of the following reasons:

a) The Balancing Mechanism for Capacity closed with a total amount of Capacity sold and purchased, which was not enough to cover the Capacity Requirements of the Market Participants with negative Capacity Balances, as set out in Clause 9.2.8.1.a);

b) A Market Participant, with negative Capacity Balance, was excluded to participate in the Balancing Mechanism for Capacity due to failure to provide the requisite Advance Instalment as required by the Market Operator;

c) A Market Participant, with negative Capacity Balance, whose participation in the Balancing Mechanism for Capacity was limited due to failure in providing the full amount of Advance Instalment as required by the Market Operator.

9.7.1.3. In addition to any enforcement actions taken under Clause 9.6.1.2 and Clause 9.6.1.3, any non-compliance with the ex-post Capacity Obligations as per Clause 9.7.1.2 shall be dealt in accordance with the provisions of Clause 10.5.4.6.

9.7.1.4. In all cases other than as provided in Clause 9.7.1.2 above, compliance of all Market Participants with Ex-post Capacity Obligations shall be considered fulfilled.

9.7.2. UPDATE OF THE STATUS OF FIRM CAPACITY CERTIFICATES

9.7.2.1. After closing of the Balancing Mechanism for Capacity, the Market Operator shall make an adjustment in the Firm Capacity Certificates, which were blocked for backing a Load Following or Customized Contract with a BPC.

9.7.2.2. To make this adjustment, the Market Operator shall:

a) upon request of the concerned Market Participant, change the status of the Firm Capacity Certificates, which were used to back up a Standardized Load Following Supply Contract or a Customized Contract pursuant to Clauses 3.3.3.3.d) or 3.4.3.4, as the case may be, from "Blocked" to "Available";

b) determine the requisite number of Firm Capacity Certificates that the Competitive Supplier needs to back up the registered Contracts, wherein the Capacity sold is dependent on the Capacity demanded by the BPCs. The Market Operator shall determine such number as:

$$CS\_CR_j[MW] = max_{\forall h \in SPH}\left(\sum_{\forall BPC_{i,j}} Act\_E_{i,j,h}\right)$$

Where:

CS_CR_j is the amount of Capacity required by the Competitive Supplier "i" to back up the Contracts with BPCs, in which the Capacity sold is dependent on the Capacity taken by the BPC, in MW;

$Act\_E_{i,j,h}$ is the total Energy supplied by the Competitive Supplier "j", to BPC "i" in hour "h" included in "Critical Hours", calculated pursuant to Clause 5.5.2.2.a), in MWh;

$\sum_{\forall BPC_{i,j}}$ means the sum over all BPCs "i" which have Contracts with the Competitive Supplier "j", in which the Capacity sold is dependent on the Capacity taken by the BPC;

$max_{\forall h \in SPH}$ means the maximum value occurred during the System Peak Hours of the previous Fiscal Year.

c) determine the number of Firm Capacity Certificates, which shall be blocked, as under:

$$\#Block\_FCC_{CSj} = CS\_CR_j * 10$$

Where:

$\#Block\_FCC_{CSj}$ is the number of Firm Capacity Certificates of the Competitive Supplier "j" that should be blocked to back up the registered Contracts in which the Capacity sold is dependent on the Capacity demanded by the BPCs;

CS_CR_j is the amount of Capacity required by the Competitive Supplier "i" to back up the Contracts with BPCs, calculated pursuant to clause 9.7.2.2.b) above, in MW.

9.7.2.3. The value of $\#Block\_FCC_{CS,j}$ shall be rounded to the nearest integer number.

9.7.2.4. In case the number of the Firm Capacity Certificates, having the status of "Available", of the concerned Competitive Supplier is equal or higher than the number of Firm Capacity Certificates that are required to be blocked pursuant to Clause 9.7.2.2.c), the Market Operator shall, if requested by the concerned Market Participant, change the status of such number of Firm Capacity Certificates, from "Available" to "Blocked". The Market Operator shall intimate the Competitive Supplier about the changes it has made in the Firm Capacity Register.

9.7.2.5. In case the number of the Firm Capacity Certificates, having the status of "Available" of the concerned Competitive Supplier is lower than the number of Firm Capacity Certificates that are required to be blocked pursuant to Clause 9.7.2.2.c), the Market Operator shall:

a) change the status of all Firm Capacity Certificates of the concerned Competitive Supplier from "Available" to "Blocked";

b) intimate the concerned Competitive Supplier about the changes it has made in the Firm Capacity Register;

c) inform the Competitive Supplier that existing number of Firm Capacity Certificates are not enough to back up its existing Contracts with BPCs; and

d) require the concerned Competitive Supplier to contract additional Capacity or to deregister one or more Contracts following the procedure set out in Section 3.6 and the Market Operator may not register any new Contract, other than Contracts for increasing the Credited Capacity of the concerned Market Participant, till the time the matter is resolved.

Chapter 10. COMPLIANCE WITH Ex-ANTE CAPACITY OBLIGATIONS

10.1. PURPOSE

10.1.1.1. The purpose of this Chapter is to provide a mechanism for verification of compliance with Capacity Obligations of Market Participants and to take the necessary actions in case of non-compliances by Market Participants.

10.2. CAPACITY OBLIGATIONS OF MARKET PARTICIPANTS

10.2.1. OBLIGATION OF CONTRACTING CAPACITY

10.2.1.1. An Electric Power Supplier, a BPC enrolled as a Market Participant and an Electric Power Trader engaged in Firm Exports shall have required Capacity, either provided by its own Generation Plants or purchased through registered Contracts, for the current and subsequent years as detailed in Clause 10.3.1.1 below, to cover a percentage of its forecasted demand as provided in this Code.

Note: For the avoidance of doubt, it is clarified that the Capacity Obligations are the minimum requirements to be fulfilled by the above-mentioned Market Participants. These Market Participants can procure more generation than what is needed for the compliance with Capacity Obligations, however, such additional procurement of generation will be subject to the applicable, legal, policy and regulatory framework.

10.3. DEMAND FORECASTS

10.3.1. SUBMISSION OF DEMAND FORECASTS

10.3.1.1. Every year, before (October 30th) the Market Operator shall require and the Market Participants mentioned in Clause 10.2.1.1 above, to submit their updated demand forecast covering a period of:

a) for Suppliers of Last Resort: Current year and following four (4) years;

b) for Competitive Electric Power Suppliers: Current year and following four (4) years;

c) for BPCs: Current year and following four (4) years; and

d) for Electric Power Traders engaged in Firm Exports: Current year and following four (4) years.

10.3.1.2. The demand forecast submitted by a Market Participant shall include, for each year, at least:

a) the total amount of Energy to be supplied/withdrawn;

b) the expected yearly Maximum Demand, indicating the month in which this Maximum Demand is expected to be taken; and

c) the expected Maximum Demand to be supplied at System Peak Hours.

10.3.1.3. The Market Participants shall submit the required information before (November 15th) of each year.

10.3.1.4. The Market Operator shall make a CCOP containing:

a) Details of the information to be submitted by the Market Participants;

b) forms/templates for submission of information.

10.3.2. DEMAND FORECAST OF SUPPLIERS OF LAST RESORT

10.3.2.1. The Demand Forecast submitted by a Supplier of Last Resort shall be prepared using appropriate models or algorithms and by taking into account the latest available information, particularly, the following:

a) the demand of its current consumers;

b) the expected growth in the number of consumers and their demand;

c) notices received from BPCs informing to end the contracted supply and their intention to contract such supply from Competitive Electric Power Suppliers;

d) estimations regarding the number of BPCs, and the associated demand, which may end the contracted supply with the Supplier of Last Resort to receive such supply from Competitive Electric Power Suppliers;

e) estimations regarding the number of BPCs, and the associated demand, which may end the contracted supply with Competitive Electric Power Suppliers or other Market Participants, which may return to receive such supply from the Supplier of Last Resort;

f) the effect of loss reduction plans implemented by the relevant Distribution Licensee;

g) the effect of plans, prepared either by the Supplier of Last Resort or the relevant Distribution Licensee, aimed at reducing consumption at the peaks;

h) the effect of distributed generation;

i) any other important factor affecting the forecast.

10.3.2.2. The Demand Forecast submitted by a Supplier of Last Resort shall be based on the Demand Forecast submitted by such Supplier of Last Resort to the Authority in the latest approved Power Acquisition Programme in accordance with applicable power procurement regulations.

10.3.2.3. The Market Operator shall compare the Demand Forecast submitted by a Supplier of Last Resort with the demand forecast included in the latest Power Acquisition Programme approved by the Authority. In case both forecasts are materially different, the Market Operator shall inform the Authority accordingly. The Market Operator shall use the forecast submitted by the Supplier of Last Resort for calculation of the Capacity Obligations unless directed otherwise by the Authority.

10.3.3. DEMAND FORECAST OF COMPETITIVE ELECTRIC POWER SUPPLIERS

10.3.3.1. The Demand Forecast of a Competitive Supplier shall include the demand of all those BPCs:

a) which have signed Contracts with the Competitive Electric Power Supplier and the same have been registered with the Market Operator or are in the process of registration; plus

b) which have valid Contracts or irrevocable letter of commitments with BPCs which will become effective at a later date and, for such reason, may have not been submitted for registration with the Market Operator at the time of submitting the forecast.

For the avoidance of doubt, the demand of BPCs which have formally given a notice to the Supplier of Last Resort, about its intention to contract its supply from the Competitive Supplier shall be included in this forecast.

10.3.3.2. The information contained in the forecast of the Competitive Supplier shall include information only up to the expiry date of the Contract or the irrevocable letter of commitment. For any subsequent periods, it shall be assumed that the relevant BPC has ceased to be supplied from the Competitive Electric Power Supplier.

10.3.3.3. In case, the Contract or irrevocable letter of commitment does not have a certain expiry date, it shall be considered that the Contract or irrevocable letter of commitment is valid for all the reported period, and the associated demand shall be included in the Competitive Supplier forecast.

10.3.4. DEMAND FORECAST OF BPCS

10.3.4.1. A BPC, which is enrolled as a Market Participant, shall submit to the Market Operator its Demand Forecast for all the periods for which it has registered Contracts for Energy and/or Capacity with Competitive Electric Power Suppliers.

10.3.4.2. For the period after the expiry of the registered Contracts, the BPC shall include in its forecast:

a) its best estimation of the Energy and peak demand to be consumed, in case the BPC intends to continue being enrolled as a Market Participant; or

b) Zero (0.), if the BPC intends to withdraw from the Market as a Market Participant and obtain its supply of electric power from the Supplier of Last Resort.

10.3.5. DEMAND FORECAST OF TRADERS INVOLVED IN FIRM EXPORT

10.3.5.1. A Trader involved in Firm Export, shall submit to the Market Operator its demand forecast for all the periods for which it has registered Contracts for Energy and/or Capacity with the Market Operator or is planning to register such Contracts.

10.3.6. REVIEW OF THE DEMAND FORECASTS

10.3.6.1. The Market Operator shall review the submitted information and assess its authenticity through tests and checks as deemed appropriate. The Market Operator may require confirmation and/or clarifications of the provided information. The concerned Market Participants shall submit the requisite information within ten (10) Business Days.

10.3.6.2. The Market Operator shall utilize the values submitted by the Market Participants, either those originally submitted or the revised values as per provisions of Clause 10.3.6.1, for verifying compliance with the Capacity Obligations.

10.3.6.3. Where in the opinion of the Market Operator, the information submitted by a Market Participant for its demand forecast is false, fabricated or forged, especially where the said information may have material impact on the compliance with Capacity Obligations, it may assess the matter and if deemed appropriate, may in addition to availing any other legal remedy that may be available to the MO, refer the matter to the Authority for appropriate legal action.

10.3.6.4. The CCOP prepared under Clause 10.3.1.4 above, shall also include details about the tests and checks to be performed on the submitted information.

10.4. CAPACITY OBLIGATIONS

10.4.1. CAPACITY OBLIGATION OF SUPPLIERS OF LAST RESORT

10.4.1.1. The Capacity Obligation of a Supplier of Last Resort, for each year in which this obligation is verified by the Market Operator, shall be calculated as:

$$CO_{BSi,p} = \frac{MD_{PH,i,p}}{(1 - Tloss_p)} * (1 + RM_p) * {}^{OB\%_{BS,p}}/_{100}.$$

Where:

- $CO_{BSi,p}$ is the Capacity Obligation of the Supplier of Last Resort *"i"* in the period *"p"* which will be verified by the Market Operator as provided in Section10.5;
- $MD_{PH,i,p}$ is the Maximum Demand at System Peak Hours of the Supplier of Last Resort *"i"* in the period *"p"*. The value of $MD_{PH,i,p}$ will be the forecasted Maximum Demand at System Peak Hours, submitted by the involved Supplier of Last Resort to the Market Operator, as per the requirements set out in Section 10.3, for the current year and all periods immediately thereafter;
- $OB\%_{BS,p}$ is the Capacity Obligation Percentage, applicable to Suppliers of Last Resort, corresponding to period *"p"* as provided in Sub-Section 18.2.3;
- $Tloss_p$ is the value of the cap (expressed in percentage) on Transmission losses of NTDC as determined by the Authority in the latest tariff determination;
- RM_p is the Reserve Margin applicable to period "p".

10.4.2. CAPACITY OBLIGATIONS OF COMPETITIVE SUPPLIERS

10.4.2.1. The Capacity Obligation of a Competitive Supplier, for each year in which this obligation is verified by the Market Operator, shall be calculated as:

$$MCO_{CSj,p} = \frac{MD_{PH,j,p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * {}^{OB\%_{CS,p}}/_{100}.$$

Where:

- $MCO_{CSj,p}$ is the mandatory Capacity obligation, of the Competitive Supplier *"j"* in the period *"p"* which will be verified by the Market Operator as provided in Sections 10.5;
- $MD_{PHj,p}$ is the Maximum Demand at System Peak Hours of the Competitive Supplier *"j"* in the period *"p"*. The value of $MD_{PHj,p}$ will be the forecasted Maximum Demand at System Peak Hours, corresponding to the Contracted Supply, submitted by the relevant Competitive Supplier to the Market Operator, as per the requirements provided in Section 10.3, for the current year and all periods immediately thereafter;
- $OB\%_{CS,p}$ is the Capacity Obligation Percentage, applicable to Competitive Electric Power Suppliers, corresponding to period *"p"* as provided in Sub-Section 18.2.3;
- Tlossp is the value of the cap (expressed in percentage) on Transmission losses of NTDC as determined by the Authority in the latest tariff determination;

- $DistLoss_d$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d" at which the BPC supplied by the Competitive Supplier is connected, as determined by the Authority for the relevant Distribution Licensee. In case any BPC supplied by the Competitive Supplier is not connected to the Network of a Distribution Licensee, this factor shall not apply;
- RM_p is the Reserve Margin applicable to period "p".

10.4.3. CAPACITY OBLIGATIONS OF BPCS ENROLLED AS MARKET PARTICIPANTS

10.4.3.1. The Capacity Obligation of a BPC enrolled as a Market Participant, for each year in which this obligation is verified by the Market Operator, shall be calculated as:

$$CO_{BPCk.p} = \frac{MD_{PH.k.p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * {}^{OB\%_{BPC.p}}/_{100}.$$

Where:

- $CO_{BPCk,p}$ is the Capacity obligation, of the BPC enrolled as Market Participant *"k"* in the period *"p"* which will be verified by the Market Operator as provided in Section 10.5;
- $MD_{PH,k,p}$ is the Maximum Demand at System Peak Hours of the BPC enrolled as Market Participant *"k"* in the period *"p"*. The value of $MD_{PH,k,p}$ will be the forecasted Maximum Demand at System Peak Hours, corresponding to the contracted Supply, submitted by the relevant BPC to the Market Operator, as per the requirements set out in Section 10.3, for the current year and all periods immediately thereafter;
- $OB\%_{BPC,p}$ is the Capacity Obligation Percentage, applicable to BPCs enrolled as Market Participants, corresponding to period *"p"* as provided in Sub-Section 18.2.3;
- $Tloss_p$ is the value of the cap (expressed in percentage) on Transmission losses of NTDC as determined by the Authority in the latest tariff determination;
- $DistLoss_d$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d" at which the BPC is connected, as determined by the Authority for the relevant Distribution Licensee. In case any BPC is not connected to the Network of a Distribution Licensee, this factor shall not apply;
- RM_p is the Reserve Margin applicable to period "p".

10.4.4. CAPACITY OBLIGATIONS OF FIRM EXPORTS

10.4.4.1. The Capacity Obligation of a Trader involved in Firm Export, for each year in which this obligation is verified by the Market Operator, shall be calculated as:

$$CO_{BPCk,p} = \frac{MD_{PH.k.p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * {}^{OB\%_{BPC.p}}/_{100}.$$

Where:

- $CO_{BPCk,p}$ is the Capacity obligation, of Trader *"k"* in the period *"p"* which will be verified by the Market Operator as provided in Section 10.5;
- $MD_{PH,k,p}$ is the Maximum Demand at System Peak Hours of the Trader involved in Firm Export *"k"* in the period *"p"*. The value of $MD_{PH,k,p}$ will be the forecasted Maximum Demand at System Peak Hours, corresponding to the contracted Supply, submitted by the relevant Trader to the Market Operator, as per the requirements set out in Section 10.3, for the current year and all periods immediately thereafter;

- $OB\%_{BPC,p}$ is the Capacity Obligation Percentage, applicable to Trader involved in Firm Export, corresponding to period "p" as provided in Sub-Section 18.2.3;
- Tlossp is the value of the cap (expressed in percentage) on Transmission losses of NTDC as determined by the Authority in the latest tariff determination;
- $DistLoss_d$ is a standard distribution loss coefficient for a particular voltage level of Distribution Licensee "d" at which the Export is connected, as determined by the Authority for the relevant Distribution Licensee. In case any Export is not connected to the Network of a Distribution Licensee, this factor shall not apply;
- RM_p is the Reserve Margin applicable to period "p".

10.5. EX-ANTE VERIFICATION OF CAPACITY OBLIGATIONS (CURRENT AND SUBSEQUENT YEARS)

10.5.1. GENERAL

10.5.1.1. Every year prior to July 31st, the Market Operator shall verify compliance with the Capacity Obligations of Market Participants which have such obligations, for the current and following years, calculated pursuant to Section10.4. The number of years to be verified shall be the same as provided in Sub-Section 10.3.1, for which the forecasts were submitted.

10.5.1.2. The Market Operator shall communicate the preliminary results of the verification to each relevant Market Participant. In case a Market Participant considers that an error or discrepancy exists in the calculations done by the Market Operator for the verification of compliance with the Capacity Obligations, it shall submit to the Market Operator a written Review Request within ten (10) Business Days of receipt of such communication from the Market Operator.

10.5.1.3. The Review Request shall clearly state the reasons for the claim, the items containing an error, inaccuracy or mis-interpretation, accompanied with supporting documents.

10.5.1.4. After receipt of the Review Request, the Market Operator shall review the request and decide whether there is any error or discrepancy in the calculations that it has performed and if required, it may hold a meeting with the relevant Market Participant to settle the matter. If the Market Operator does not agree with the claim, it shall intimate the same to the relevant Market Participants along with reasons thereof.

10.5.1.5. Where the market operator, after review of the calculations finds that there is an error or discrepancy as claimed by the relevant Market Participant, it shall rectify the error and shall inform the concerned Market Participant accordingly.

10.5.2. INFORMATION REQUIRED FROM MARKET PARTICIPANTS

10.5.2.1. Every year, before June 30th, the Market Operator shall require each Market Participant, as mentioned in Clause 10.3.1.1 above, to submit information regarding Generation projects, planned or under construction, or Contracts with existing Generation Plants which may be taken into account for determining the Capacity allocated to such Market Participant.

10.5.2.2. Such information shall contain all supporting documents to demonstrate each project's firmness, including one or more of the following:

a) for projects being developed by the Market Participants:

a.1. Temporary Firm Capacity Certificates or documents showing the submission of the application for issuance of such certificates;

a.2. EPC Contracts, clearly stating the project commissioning date; and

a.3. any other document the Market Participant considers appropriate to assess the actual status of the project construction;

b) For projects being developed or already developed by third parties, which have signed a Contract with the Market Participant, the duly signed Contract, clearly indicating the date at which this Contract will become effective and enforceable along with the associated Temporary Firm Capacity Certificates.

10.5.3. VERIFICATION OF THE SUBMITTED INFORMATION

10.5.3.1. The Market Operator shall review the submitted information for each project and determine whether such project may qualify for compliance with the Capacity Obligations. In conducting such assessment, the Market Operator may:

a) request additional information, which shall be provided within the specified time;

b) conduct assessments aimed at determining the accuracy of the submitted information; and/or

c) request the advice of reputable experts at the cost of the concerned Market Participant.

10.5.3.2. For projects or Contracts submitted by a Supplier of Last Resort, the Market Operator shall verify whether such project or Contract is included in the latest Power Acquisition Programme approved by the Authority, as per applicable power procurement regulations, and in case the project or Contract is not included in such plan, it shall not be considered for compliance with Capacity Obligations. For projects or Contracts included in the Power Acquisition Programme, the project characteristics as well as the expected COD shall be the same. In case there are differences between the Power Acquisition Programme and the request made by the Supplier of Last Resort, regarding the project Capacity or the commissioning date, the lower value of Capacity and the later commissioning date shall be used by the MO and the matter shall also be intimated to the Authority.

10.5.3.3. Based on the analysis and evaluations performed, the Market Operator shall classify each project in any of the following three categories:

a) Eligible for crediting Capacity, at the date requested by the Market Participant;

b) Eligible for crediting Capacity, at a later date than the request made by the Market Participant;

c) Not eligible for crediting Capacity.

10.5.3.4. Only the projects belonging to the first two categories, as stipulated in Clause 10.5.3.3 above, will be considered for compliance with the Capacity Obligations of the involved Market Participant.

10.5.4. DETERMINATION OF COMPLIANCE WITH THE CAPACITY OBLIGATIONS

10.5.4.1. The Market Operator shall monitor compliance with the Ex-ante Capacity Obligations of each Market Participants, as mentioned in Clause 10.3.1.1above, for each year in which the Market Participant has such obligations, through the comparison of two yearly values: the Capacity Obligation and the Credited Capacity of such Market Participant for each year.

10.5.4.2. The Capacity Obligation of each Market Participant, for each year in which this obligation exists, shall be determined by the Market Operator according to the provisions of Sub-Section 10.4.1, Sub-Section 10.4.2 or Sub-Section 10.4.3, as the case may be.

10.5.4.3. The Credited Capacity of each Market Participant, for the Ex-ante verification of its yearly obligations will be the sum of:

a) Firm Capacity of Generation Plants owned by the Market Participant, which have been issued the corresponding Firm Capacity Certificates by the Market Operator, and not sold to other Market Participants through registered Contracts.

Explanation:

The Credited Capacity to the Market Participants or BPCs shall be calculated as the addition of the values stated in the Firm Capacity Certificates of all the Generation Plants it owns, minus the Capacity sold, every year, to other Market Participants through registered Contracts.

b) Capacity acquired through registered Contracts executed with Generators or other Market Participants.

Explanation:

The Capacity Credited in this case shall be calculated as the yearly addition of the Capacity purchased through all the registered Contracts. The contracted Capacity shall be clearly stated during the registration of the Contract.

c) Capacity which will be installed, by the Market Participant, or it will be acquired through Contracts from Generation Plants which are under construction, provided such Contracts are considered eligible by the Market Operator, according to the provisions of Clause 10.5.3.3, such Capacity will be credited to the relevant Market Participant starting from the COD of the Generation Plant, as approved by the Market Operator.

The Capacity Credited in this case shall be determined based on:

c.1. the values stated in the Temporary Firm Capacity Certificates, in cases in which the Market Operator has issued such certificates; or

c.2. the declared Capacity to be installed, as per the application, as provided in Clause 10.5.3.3, multiplied by the Equivalent Availability Factor stated in Table 1 of Sub-Section 8.4.2.

10.5.4.4. In case the Credited Capacity of a Market Participant is above (98%) of the Capacity Obligation determined for such Market Participant, in all of the years evaluated, the obligation shall be considered fulfilled.

10.5.4.5. In the case the Credited Capacity of a Market Participant is lower than (98%) of the Capacity Obligation determined for such Market Participant, in one or more of the years evaluated, the obligation shall be considered not fulfilled.

10.5.4.6. The Market Operator shall categorize non-compliance with the Capacity Obligations of each Market Participant as:

a) Minor Non-Compliance: Non-compliance with the ex-ante Capacity Obligations occurs only in one or two of the years being verified and, the difference between the Capacity Obligation and the Credited Capacity is below five percent (5%) during each year.

b) Serious Non-Compliance: In case there is a non-compliance with the ex-post Capacity Obligations as per Clause 9.7.1.2 or a non-compliance with the ex-ante Capacity Obligation which cannot be categorized as Minor Non-Compliance.

10.6. <u>DISSEMINATION OF THE RESULTS AND ACTIONS IN CASE OF NON-COMPLIANCE</u>

10.6.1. COMPLIANCE WITH CAPACITY OBLIGATIONS REPORT

10.6.1.1. The Market Operator shall prepare a report titled as "Compliance with Capacity Obligations Report", including the calculations performed, the information being utilized and the results of the verification. The report shall contain separate sections for the ex-ante and ex-post verifications, and analysis and evaluations for each Market Participant individually along with a summary of the most important conclusions which shall be published on MO Website.

10.6.2. DISPUTE RESOLUTION

10.6.2.1. Any Market Participant, feeling aggrieved of the decision of the Market Operator regarding the compliance with the Capacity Obligations, may file a dispute with the Market Operator according to the provisions of Chapter 14.

10.6.3. ACTIONS TO BE TAKEN IN CASE OF NON-COMPLIANCE

10.6.3.1. The Market Operator shall issue a warning notice to all Market Participants which are involved in a Minor Non-Compliance. In such notice, the Market Operator shall require the involved Market Participant, to solve the Non-compliance by contracting additional Firm Capacity or installing additional Generation. The Market Operator may not register any new Contract, other than Contracts for increasing the Credited Capacity of the concerned Market Participant, till the time the Non-compliance is resolved.

10.6.3.2. The Market Operator shall issue a Serious Non-Compliance Notice to all Market Participants which are involved in a Serious Non-Compliance, requiring them to solve the Non-compliance within a specified timeframe, by contracting additional Capacity or installing additional Generation. Failure to comply with the requirement of the Serious Non-Compliance Notice shall constitute an Event of Default and shall be dealt with according to the provisions of Chapter 17. Such situation shall also be communicated to the Authority so that it may take appropriate action, including the imposition of penalties.

10.6.3.3. Till the time the Serious Non-Compliance is fully resolved, the Market Operator may not register any new Contract, other than Contracts for increasing the Credited Capacity of the concerned Market Participant.

10.6.1. DETERMINATION OF THE CAPACITY OBLIGATIONS OF AN APPLICANT AT THE TIME OF ENROLMENT AS A MARKET PARTICIPANT OR ADDITION OF A BPC BY A COMPETITIVE SUPPLIER

10.6.1.1. The Market Operator shall determine the Capacity Obligations of an Applicant intending to enroll as a Market Participant in any of the Category as specified in Clause 10.2.1.1 or where a Competitive Supplier intends to add a new BPC. The procedure set forth in sections 10.3, 10.4 and 10.5 shall *mutatis mutandis* apply for determination of Capacity Obligations and verification of compliance thereof.

10.6.1.2. Where the Applicant is not able to demonstrate compliance with the Capacity Obligations determined by the Market Operator, the Market Operator may enroll such applicant as Market Participant subject to fulfilment of other conditions of this Code, however, such Market Participant shall not be entitled to carry out any commercial transactions in CTBCM till the time it fulfils the requirements of the Capacity Obligations as determined by the Market Operator.

10.6.1.3. Where the Competitive Supplier is not able to demonstrate compliance with the Capacity Obligations determined by the Market Operator, the Market Operator shall not allow addition of the new BPC till the time it fulfils the requirements of the Capacity Obligations as determined by the Market Operator.

Chapter 11. YEARLY SETTLEMENT STATEMENTS (FOR BMC)

11.1. Yearly Settlement

11.1.1. Contents of yearly settlement statement

11.1.1.1. The Market Operator shall make yearly Settlement, for Balancing Mechanism for Capacity, of each Market Participant or Service Provider, for the previous year, which may include, *inter alia*, the following:

a) the Amounts Payable or Receivable by a Market Participant, as the case may be, for the participation in the Balancing Mechanism for Capacity;

b) The Amounts Payable to or Amounts Receivable by a Market Participant due to a correction in the Balancing Mechanism for Capacity arising from Extraordinary Yearly Settlement Statement as per Sub-Section 11.3.4; and

c) The Amount Payable to or Receivable by the Market Participant on account of accrued interest for previous late payments or default in making payments.

11.2. Applicable Taxes

11.2.1. Applicability of Taxes

11.2.1.1. All Settlements calculated by the Market Operator pursuant to this Chapter shall be subject to the applicable taxes as per Applicable Law.

11.3. Settlement Statements

11.3.1. Preliminary Yearly settlement statements

11.3.1.1. Within seven (7) Business Days of execution of the BMC as per Clause 9.6.2.1, the Market Operator shall send, through electronic means, to each Market Participant and to the Service Providers, a Preliminary Yearly Settlement Statement.

11.3.1.2. For Market Participants, the Preliminary Yearly Settlement Statement shall, *inter alia*, include:

a) the Amounts Payable and Amounts Receivable in the Balancing Mechanism for Capacity; and

b) if applicable, the corrections resulting from an Extraordinary Yearly Settlement Statement.

11.3.2. Claims against the Preliminary Yearly Settlement Statements

11.3.2.1. Where a Market Participant considers that an error or discrepancy exists in the Preliminary Yearly Settlement Statement, it shall submit to the Market Operator a written Review Request within five (5) Business Days of receipt of the Preliminary Yearly Settlement Statement.

11.3.2.2. The Review Request shall clearly state the issuance date of the Preliminary Yearly Settlement Statement, the item claimed, the reasons for the claim, the amount claimed, and shall be accompanied with supporting documents.

11.3.2.3. After receipt of the Review Request, the Market Operator shall review the request and decide whether there is any error or discrepancy in the Preliminary Yearly Settlement Statement and if required, it may hold a meeting with the relevant Market Participant to settle the matter. If the Market Operator does not agree with the Review Request, it shall intimate the same to the relevant Market Participants along with reasons thereof.

11.3.2.4. Where the Market Operator, after review of the Preliminary Yearly Settlement Statement finds that there is an error or discrepancy as claimed by the relevant Market Participant, it shall rectify the error before issuing the Final Yearly Settlement Statement and shall inform all the relevant Market Participants accordingly.

11.3.3. FINAL YEARLY SETTLEMENT STATEMENTS

11.3.3.1. Within twenty-five (25) Business Days after issuance of the Preliminary Yearly Settlement Statement, the Market Operator shall issue the Final Yearly Settlement Statement to each Market Participant, using a format similar to the Preliminary Yearly Settlement Statement.

11.3.3.2. A Market Participant may challenge the Final Yearly Settlement Statement along with reasons thereof within ten (10) Business Days of its issuance. The challenge may relate to:

a) the metered values and contracted quantities of Capacity; or

b) the settled amounts in the Balancing Mechanism for Capacity, Default Interest for late payments or any other item which has been included in the Final Yearly Settlement Statement.

11.3.3.3. The Market Operator and the Market Participant shall make reasonable efforts to mutually settle the matter within thirty (30) Business Days after the challenge is submitted to the Market Operator as per dispute resolution mechanism provided in Chapter 14.

11.3.4. EXTRAORDINARY YEARLY SETTLEMENTS

11.3.4.1. Market Operator shall issue an Extraordinary Yearly Settlement Statement for a year, where:

a) the dispute is settled between Market Participants according to the dispute resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement; or

b) the dispute is settled between a Market Participant and a Service Provider according to the dispute resolution mechanism and has attained the finality, which requires modification in the amounts included in the Final Settlement Statement.

11.3.4.2. The Extraordinary Settlement Statement as provided in Clause 11.3.4.1 shall supersede the issued Final Yearly Settlement Statement for such year.

11.3.4.3. The Market Operator shall calculate, for each Market Participant, the difference between the Extraordinary Yearly Settlement Statement and the Final Yearly Settlement Statement originally issued according to Sub-Section 11.3.1, and shall decide whether to include such amounts in the next Preliminary and Final Yearly Settlement Statement, as the case may be, or to issue the advices as per Section 11.4 below.

11.3.5. FAILURE OF THE MARKET SETTLEMENT SYSTEM

11.3.5.1. In case of an emergency or failure of the Market Settlement System, the Market Operator may issue an Estimated Yearly Settlement Statement and may modify the schedule for issuing Preliminary Yearly Settlement Statements or Final Yearly Settlement Statements, as the case may be. In such cases, the Market Operator shall inform all Market Participants and Service Providers the temporary procedural changes as soon as possible. The Market Operator shall immediately inform the Authority of any emergency resulting in failure of the Market Settlement System along with the estimated time period required to address such emergency or failure.

11.4. DEBIT AND CREDIT ADVICES

11.4.1. ADVICE TO MARKET PARTICIPANTS

11.4.1.1. The Market Operator, within five (5) Business Days after issuance of the Final Yearly Settlement Statement or Extraordinary Yearly Settlement Statement, as the case may be, shall:

a) issue a Debit Advice to all Market Participants and which have to pay the Amounts Payable as per the Final Yearly Settlement Statement or the Extraordinary Yearly Settlement Statement, as the case may be. For the avoidance of doubt, it is hereby clarified that the Market Operator shall exclude from the Amounts Payable such amounts which have already been paid to the Market Operator before the final administration of the Balancing Mechanism for Capacity;

b) issue a Credit Advice to all Market Participants who will receive a payment as per the Final Yearly Settlement Statement or the Extraordinary Yearly Settlement Statement, as the case may be.

11.4.1.2. The Market Operator, in this process, shall act as an independent entity, without assuming any payment responsibility. Obligation of payment shall remain with the relevant Market Participants. For the avoidance of doubt, the Market Operator shall not be held liable for any kind of non-payment by any of the Market Participants.

11.4.2. DISAGREEMENTS WITH THE ADVICE

11.4.2.1. Each Market Participant which receives a Debit or Credit Advice, as per clause 11.4.1.1 above, shall pay the required amount, and shall be entitled to receive the amount, shown in the Final Yearly Settlement Statement or the Extraordinary Yearly Settlement Statement, as the case may be, on the Payment Due Date, whether or not there is any dispute regarding the Amount Payable or the Amount Receivable.

11.4.2.2. The payment of the amount by the Market Participant or the Market Operator, as the case may be, pursuant to clause 11.4.2.1 shall not prejudice the right of the Market Participant to seek resolution of the dispute pursuant to Chapter 14.

Chapter 12. PAYMENT SYSTEM

12.1. COMPONENTS OF THE PAYMENT SYSTEM

12.1.1. MARKET OPERATOR BANK ACCOUNTS

12.1.1.1. The Market Operator shall open and maintain such number of bank accounts as mentioned in Clause 12.1.1.3, in order to perform its duties as mandated under this Code. A separate ledger account shall also be opened for each Market Participant for the accounts as referred to in Clause 12.1.1.3.

12.1.1.2. The Authority may allow Market Operator to recover costs incurred in connection with opening, maintaining, and administering the bank accounts through the Market Operator Fee.

12.1.1.3. The Market Operator shall hold and operate the following separate bank accounts:

a) Market Operator Security Cover Account, to and from which payments according to this Code, shall be made, which includes monthly and yearly payments for:

a.1. the Balancing Mechanism for Energy;

a.2. Ancillary Services, Transmission Must Run and Reliability Must Run;

a.3. Market Operator Fee;

a.4. other amounts included in a Debit/Credit Advice issued by the Market Operator which relates to monthly Settlements, in accordance with this Code;

a.5. any amounts deposited by the Market Participants with the Market Operator in respect of initial amount of Security Cover for monthly Settlements or as replenishment of the Security Covers for monthly Settlements;

a.6. any amounts deposited by the Market Participants with the Market Operator in respect of initial Advance Instalment for yearly Settlements or as replenishment of the same;

a.7. the Balancing Mechanism for Capacity;

a.8. Default Interest for payments not made at the Payment Due Date for monthly or yearly Settlements;

b) Market Operator Settlement Guarantee Cover Account, in accordance with Clause 12.1.1.6;

c) Market Operator operational accounts in accordance with Clause 12.1.1.8.

12.1.1.4. All Market Participants shall make all payments due under the Debit Advice into the Market Operator Security Cover Account, by Close of Banking Business on the Payment Due Date. The Market Operator shall pay to the Market Participants from the Market Operator Security Cover Account, under Credit Advice, by Close of Banking Business on the Clearing Day or any other date as specified in the Credit Advice.

12.1.1.5. Default Interest for payments not received at the Payment Due Date, calculated in accordance with Clause 12.3.6.1, shall first be used as compensation for any expenses, loss or costs incurred by the Market Operator on account of Non-Compliance by any Market Participant or Service Provider.

12.1.1.6. The Market Operator shall operate the Settlement Guarantee Cover Account in the following manner:

a) any amounts paid to the Market Operator in respect of initial Guarantee Amount or as replenishment of the same, shall be deposited in Market Operator Settlement Guarantee Cover Account;

b) on the Clearing Day, if needed, the funds available in the Settlement Guarantee Cover Account will be transferred to the Market Operator Security Cover Account in order to make payments as per relevant monthly Settlement Statements;

c) the amounts used by the Market Operator from the Settlement Guarantee Cover Account shall be replenished by the Market Participants.

12.1.1.7. The Market Operator shall operate the Market Operator Security Cover Account in the following manner:

a) any amounts paid to the Market Operator in respect of initial amount of Security Cover for monthly Settlements or Advance Instalment for yearly Settlement, as the case may be, or as replenishment of the same, will be deposited in the Market Operator Security Cover Account;

b) on the Clearing Day, as per requirement, the funds available in the Market Operator Security Cover Account shall be used to make payments to Market Participants as per monthly Settlement Statements or yearly Settlement Statements, as the case may be;

c) the amounts used by the Market Operator from the Market Operator Security Cover Account shall be replenished by the Market Participants in the same account.

12.1.1.8. In addition to the bank accounts mentioned above, the Market Operator shall maintain and operate such number of bank accounts in scheduled banks as are required to manage its corporate finance.

12.1.2. MARKET PARTICIPANT'S BANK ACCOUNT

12.1.2.1. Each Market Participant, except Electric Power Suppliers segregated from EX-WAPDA DISCOs, shall maintain a bank account with a scheduled bank(s) approved by the Market Operator from which payments to, and from, the Market Operator shall be made pursuant to this Code. No Market Participant shall make any change to its bank account without obtaining prior permission of the Market Operator.

12.1.3. DESIGNATED ACCOUNT OF ELECTRIC POWER SUPPLIERS SEGREGATED FROM EX-WAPDA DISCOS FOR MARKET SETTLEMENTS

12.1.3.1. The mechanism provided below shall take effect only after the Ex-WAPDA DISCOs in their role as Suppliers of Last Resort have registered Bilateral Contracts other than Legacy Contracts-CPPA-G and Legacy Contracts-DISCOs and the Market Operator has been established as a separate legal entity. Till such time, any amount that arise due to Settlement of Legacy Contracts-CPPA-G, signed or administered by the CPPA-G or EX-WAPDA DISCOs shall be paid to or paid by the Special Purpose Agent. Additionally, the Market Operator Fee shall also be collected by the Special Purpose Agent through the transfer pricing mechanism as set forth in its code.

12.1.3.2. Each EX-WAPDA DISCOs in their role as Supplier of Last Resort shall open and/or maintain a Designated Account for the purposes of settlements with the Market Operator as per this Code in a Designated Bank having a minimum long term credit rating of "A" and above as published by the State Bank of Pakistan that receive, accept and process immediately any payment in accordance with the irrevocable mandate to operate in accordance with the standing instruction given in Clause 12.1.3.6.

12.1.3.3. The Market Operator, each Electric Power Supplier/DISCO and the Designated Bank shall enter into an agreement to operate the Designated Account as per the terms and conditions of such agreement and the provisions of Clause 12.1.3.6.

12.1.3.4. Each Designated Account shall receive a significant portion, to be determined on case-to-case basis, of the revenues from sale of electric power through main Revenue Collection Bank Accounts.

12.1.3.5. The Designated Account shall be operated in accordance with the standing instructions, issued by the Market Operator and the relevant Electric Power Supplier jointly, as provided in Clause 12.1.3.6, as well as the terms and conditions of the agreement entered into among the Market Operator, the Designated Bank and the relevant Electric Power Supplier for disbursement of payments to the Market Operator and the Electric Power Supplier. Such standing instructions may be reviewed on periodic basis by the Market Operator and the relevant Electric Power Suppliers jointly and if required, necessary amendments may be made in this respect.

12.1.3.6. The Designated Bank shall be responsible for the timely disbursement of the payments from the Designated Account of such Electric Power Supplier to the Market Operator settlement accounts on receipt of instructions from the Market Operator and the relevant Electric Power Supplier as stated below:

a) the Designated Bank shall order the transfer of payments as per the instructions issued by the Market Operator for the payment of amounts on account of Settlement Guarantee Cover to the Market Operator Settlement Guarantee Cover Account;

b) when funds remain in the Designated Account after payment of amounts on account of Settlement Guarantee Cover under Clause 12.1.3.6.a) above, the Designated Bank shall order the transfer of payments on account of the initial Security Cover/replenishment of Security Cover or initial Advance Instalment/ replenishment of the Advance Instalment as instructed by the Market Operator, to the Market Operator Security Cover Account;

c) when funds remain in the Designated Account after payment of amounts on account of initial Security Cover/replenishment of Security Cover or initial Advance Instalment/ replenishment of the Advance Instalment under Clause 12.1.3.6.b) above, the Designated Bank shall order the transfer of payments on account of any instruction issued by the Market Operator pursuant to any Settlement Statement and the resulting Debit Advice to the Market Operator Security Cover Account;

d) when funds remain in the Designated Bank Account after payment of amount on account of instructions issued by the Market Operator under Clause 12.1.3.6.c) above, the Designated Bank shall order the transfer of payments as instructed by the Market Operator on account of any Debit Advice for deposit of any Default Interest to the Market Operator Security Cover Account;

e) when funds remain in the Designated Bank Account after payment of the amounts specified in the Debit Advice by Market Operator under Clause 12.1.3.6.d) above, the Designated Bank shall act in accordance with the instructions of the relevant Electric Power Supplier.

12.1.3.7. Each Designated Bank shall issue an irrevocable mandate applicable to Designated Bank Accounts, in accordance with the format mutually agreed by the Market Operator and the Electric Power Supplier/DISCO, to receive, accept and immediately process any payment requirement that is received from the Market Operator, provided that such payment requirement is fully consistent with the standing instructions given in Clause 12.1.3.6.

12.1.3.8. After the issuance of the Debit Advice by the Market Operator as per this Code, the Designated Bank shall determine if there are enough funds in the Designated Bank Account to make the required payment to satisfy the payment obligations priority in accordance with Clause 12.1.3.6.

12.1.3.9. Whenever the remaining funds in Designated Account are, or deemed to be, insufficient to comply with such obligations, the Designated Bank shall inform the relevant Electric Power Supplier and the Electric Power Supplier shall be responsible for depositing the required amount before the Payment Due Date.

12.1.3.10. The standing instructions given in Clause 12.1.3.6 shall remain applicable till the Payment Due Date and no funds shall be transferred from the Designated Account for any other purpose till the payments are made as per priority given in Clause 12.1.3.6.

12.1.3.11. At the Payment Due Date, the Designated Bank shall execute the irrevocable mandate of transferring the amount in accordance with Clause 12.1.3.6.

12.2. <u>Market Operator Payments Calendar</u>

12.2.1. Contents of the Market Operator Payments Calendar

12.2.1.1. Each year, the Market Operator shall prepare a draft Market Operator's Payments Calendar for the following fiscal year showing:

a) the dates on which the Market Operator will issue Preliminary Settlement Statements (monthly and yearly) to all Market Participants;

b) the dates on which the Market Operator will issue Final Settlement Statements (monthly and yearly) to all Market Participants;

c) the dates on which the Market Operator will issue Debit Advice to Market Participants;

d) the dates when Market Participants, which are liable to make payments, are required to make payments into the Market Operator Security Cover Account, in accordance with the issued Debit Advice;

e) the dates when the Market Participants, to which any amount is to be paid in accordance with the Credit Advice, will receive payments from the Market Operator Security Cover Account,

Provided that for the first fiscal year following the CMOD, the Market Operator's Payments Calendar shall be established pursuant to Sub-Section 12.2.3.

12.2.1.2. The Market Operator may change the contents or format of the Market Operator's Payments Calendar for future years upon prior written notification to Market Participants.

12.2.2. DATES FOR THE MARKET OPERATOR'S PAYMENTS CALENDAR

12.2.2.1. Subject to Sub-Section 12.2.3, on June 1st of each year, the Market Operator shall publish on the MO Website, a draft of the Market Operator's Payments Calendar for the following fiscal year. Any Market Participant may submit comments to the Market Operator within ten (10) Business Days after such publication.

12.2.2.2. No later than (June 25th) of each year, the Market Operator shall publish on the MO Website, the final version of the Market Operator's Payments Calendar for the following fiscal year, after considering the comments received pursuant to Clause 12.2.1.1.

12.2.2.3. The final Market Operator's Payments Calendar, made available in accordance with Clause 12.2.2.2 or Sub-Section 12.2.3, as the case may be, shall be binding on the Market Operator and on all Market Participants for the relevant fiscal year.

12.2.3. FIRST MARKET OPERATOR PAYMENT CALENDAR

12.2.3.1. Within fifteen (15) Business Days of the CMOD, the Market Operator shall publish the first Market Operator's Payments Calendar on the MO Website. This first Market Operator's Payments Calendar shall be followed by the Market Operator for the remaining period of the fiscal year.

12.2.3.2. Within five (5) Business Days following the publication of the first Market Operator's Payments Calendar, the Market Participants shall submit their comments on the first Market Operator's Payments Calendar notified by the Market Operator pursuant to Clause 12.2.3.1 above.

12.2.3.3. Within (5) Business Days of receipts of comments from the Market Participants pursuant to Clause 12.2.3.2 and taking into account their comments, the Market Operator may amend the first Market Operator's Payments Calendar, if required, and notify the Market Operator's Payments Calendar for the remaining part of the first Fiscal Year.

12.3. <u>PAYMENT PROCEDURES</u>

12.3.1. PAYMENT PROCESS FOR MONTHLY SETTLEMENTS

12.3.1.1. On the Clearing Day:

a) the Market Operator shall transfer funds from Market Operator Security Cover Account to the relevant Market Participants under the Credit Advices issued by the Market Operator in accordance with the monthly Settlement Statements. Where the Security Cover of a Market Participant who is liable for any Amount Payable, is deficient, the Market Operator may utilize Security Cover of other Market Participants available in Market Operator Security Cover Account to bridge the gap and settle all Credit Advices in full;

b) where the total funds available in respect of Security Cover for monthly Settlement, in the Marker Operator Security Cover Account, pertaining to all Market Participants, are not sufficient to make full payments to the Market Participants under the Credit Advices, the Market Operator may utilize the balance available in the Market Operator Settlement Guarantee Cover Account to bridge the gap in order to make full payment to the relevant Market Participants;

c) the Market Operator shall ensure proper accounting of all transactions.

12.3.1.2. On the next Business Day following the Clearing Day, the Market Operator shall issue Debit Advice to all Market Participants, who are liable to make any payment to the Market Operator, requiring them to pay the required amounts by the Payment Due Date. Any late payment from the Payment Due Date shall attract Default Interest calculated pursuant to Clause 18.2.6.1.

12.3.1.3. Each Market Participant shall deposit the amount shown on the Debit Advice in the Market Operator Security Cover Account or the Market Operator Settlement Guarantee Cover Account, as the case may be, by Close of Banking Business on the Payment Due Date.

12.3.2. PAYMENT PROCESS FOR YEARLY SETTLEMENTS

12.3.2.1. On the Clearing Day:

a) the Market Operator shall transfer funds from Market Operator Security Cover Account to the relevant Market Participants under the Credit Advices issued by the Market Operator in accordance with yearly Settlement Statements;

b) where the total funds available in respect of Advance Instalments for yearly Settlement, in the Marker Operator Security Cover Account, pertaining to all Market Participants are deficient to make full payment to the Market Participants under the Credit Advices, the Market Operator may reduce payments to all Market Participants on pro-rata basis while taking into account the shortfall amount;

c) the Market Operator shall ensure proper accounting of all transactions.

12.3.2.2. On the next Business Day following the Clearing Day, the Market Operator shall issue Debit Advices to all Market Participants, who are liable to make any payment to the Market Operator, requiring them to pay the required amounts by the Payment Due Date. Any late payment from the Payment Due Date shall attract Default Interest calculated pursuant to Clause 18.2.6.1.

12.3.2.3. Each Market Participant shall deposit in the Market Operator Security Cover Account the amount shown on the Debit Advices, by Close of Banking Business on the Payment Due Date.

12.3.3. DEFAULT IN MAKING PAYMENT BY A MARKET PARTICIPANT

12.3.3.1. In case of monthly Settlements, where a Market Participant defaults in making any payment due under the Debit Advice or otherwise, the Market Operator may make payments by utilizing the Settlement Guarantee Cover Amount, provided that upon recovery or receipt of such amount from the defaulting Market Participant, such amount shall be deposited back to the Market Operator Settlement Guarantee Cover Account. It is hereby clarified that payment of any amount from the Market Operator Settlement Guarantee Cover Account and/or temporary utilization of Security Cover of other Market Participants, on behalf of defaulting Market Participant, shall be without prejudice to any enforcement action, against the defaulting Market Participant, that may be taken by the Market Operator under Chapter 16.

12.3.3.2. Where there is no chance of recovery from the defaulting Market Participant, the Market Operator shall assess the impact on the Settlement Guarantee Cover amount and determine if any additional amounts are required. If required, all Market Participants shall deposit the requisite amounts, as determined by the Market Operator, within specified timeframe.

12.3.3.3. In case of yearly Settlements, where a Market Participant defaults in making any payment due under the Debit Advices or otherwise, the Market Operator may reduce payments to all Market Participants on pro-rata basis, provided that upon recovery or receipt of such amount from the defaulting Market Participant, such amount shall be paid to the relevant parties together with any interest as received from the defaulting party.

12.3.3.4. It is hereby clarified that payment by a defaulting Market Participant with the Default Interest shall not absolve such Market Participant from any enforcement action that may be taken by the Market Operator under Chapter 16.

12.3.4. SET-OFF

12.3.4.1. The Market Operator is authorised to replenish, set off or apply any amount to which any defaulting Market Participant is, or will be, entitled, for or towards the satisfaction of any of that Market Participant's debts arising under the Settlement and billing process in accordance with Chapter 7 and Chapter 11, or any penalty imposed on the Market Participant by the Market Operator pursuant to Chapter 16. The oldest outstanding amounts will be settled first in the order of the creation of such debts.

12.3.5. ORDER OF PAYMENTS

12.3.5.1. The Market Operator shall apply payments received in respect of amounts owed to Market Participants to repay the relevant debts in the order of the creation of such debts.

12.3.6. DEFAULT INTEREST

12.3.6.1. All Market Participants shall pay Default Interest, calculated pursuant to Clause 18.2.6.1 on Default Amounts for the period commencing from the relevant Payment Due Date till the date on which the payment is actually received by the Market Operator, together with any related costs incurred by the Market Operator.

12.3.6.2. In case of monthly Settlement, the Default Interest shall be parked in Market Operator Settlement Guarantee Cover Account and may be utilized by the Market Operator in the event of default as per Clause 12.3.3.2.

12.3.7. OVERPAYMENTS

12.3.7.1. Where a Market Participant receives an overpayment as a result of an error on the part of the Market Operator, it shall intimate the Market Operator of such overpayment immediately, but not later than 24 hours of the knowledge thereof.

12.3.7.2. The Market Participant shall return the received overpayment in full by the next Business Day.

12.3.7.3. If the Market Participant has not remitted the amount back to the Market Operator within the next three (3) Business Days from the date of receipt of such overpayment, the Market Operator shall be entitled to charge Default Interest on the amount of the overpayment, until the amount is credited to the Market Operator Security Cover Account, and the Market Operator shall be entitled to treat the overpayment, and any interest accruing thereon, as a Default Amount to which Clause 12.3.6.1 and 12.3.6.2 shall apply.

Chapter 13. GUARANTEE, SECURITY COVER AND ADVANCE INSTALMENTS

13.1. REQUIREMENTS FOR PROVIDING GUARANTEE AND SECURITY COVER

13.1.1. GUARANTEE AND SECURITY COVER TO BE PROVIDED BY MARKET PARTICIPANTS

13.1.1.1. Each Market Participant shall provide to the Market Operator appropriate Security Cover for expected Amounts Payable for the Energy purchased in the Balancing Mechanism for Energy, Transmission Must Run, Reliability Must Run, Ancillary Services and MO fee, calculated pursuant to this Code as advance payment.

13.1.1.2. Each Market Participant shall provide to the Market Operator appropriate Advance Instalment for Amounts Payable for the Capacity purchased in the Balancing Mechanism for Capacity calculated pursuant to this Code and included in the yearly Settlement Statements (Final or Extraordinary, as the case may be);

13.1.1.3. The Security Cover and the Advance Instalment to be provided pursuant to Clause 13.1.1.1 and Clause 13.1.1.2 above, shall be inclusive of all applicable taxes.

13.1.1.4. In addition to Security Cover required under Clause 13.1.1.1 above, the Market Participants shall also provide to the Market Operator the Settlement Guarantee Cover (the Guarantee Amount) pursuant to clause 13.1.3.4.

13.1.1.5. Security Cover for the monthly Settlement Statements shall be provided by the Market Participants:

a) before enrolment as a Market Participant, pursuant to Clause 2.3.4.1; and

b) at the time of registration of a Contract to which the Market Participant is a party.

13.1.1.6. Advance Instalment for the yearly Settlement Statements shall be provided by the Market Participants as stipulated in Clauses 9.5.1.1 or 9.5.1.5, as the case may be. .

13.1.2. ACCEPTABLE FORM OF SECURITY COVERS, GUARANTEE AMOUNT AND ADVANCE INSTALMENT

13.1.2.1. The only acceptable form of Security Covers, Settlement Guarantee Cover and Advance Instalment is cash.

13.1.3. DETERMINATION OF SECURITY COVER AND SETTLEMENT GUARANTEE COVER

13.1.3.1. The Market Operator shall make a CCOP describing a detailed methodology to determine the initial amount of Security Cover and Settlement Guarantee Cover to be provided by each Market Participant at the time of registration of a new Contract and revisions thereof.

13.1.3.2. Till the time, the CCOP is prepared as per Clause 13.1.3.1 above, as an interim measure, the following criteria shall apply for the calculation of initial amount of Security Covers:

a) Subject to Clause 12.1.3.1. for EX-WAPDA DISCOs, the amount shall be equal to the maximum Amount Payable under any Final Settlement Statement or Extraordinary Settlement Statement issued during the last one year prior to the calculation date;

b) For KE, the amount shall be calculated keeping in view its expected payments in the Market once its integration plan is approved by the Authority;

c) For other Market Participants, the initial amount shall be equal to the one-month maximum possible payable amount under a monthly Settlement Statement out of the upcoming six (6) months.

13.1.3.3. The Security Cover shall be deposited in the Market Operator Security Cover Account in the form of cash. Any return on the deposited amounts shall be distributed among the Market Participants on the basis of their respective outstanding balance in Market Operator Security Cover Account.

13.1.3.4. The initial Guarantee Amount or any revised Guarantee Amount shall be calculated by the Market Operator for all Market Participants and all Market Participants shall be required to deposit such amounts in the Market Operator Settlement Guarantee Cover Account in the form of cash. Till the time, the CCOP is prepared as per Clause 13.1.3.1, above, as an interim measure, the initial Guarantee Amount to be provided by all Market Participants shall be equal to 1.5 times the initial Security Cover amount of each Market Participant.

13.1.3.5. The Market Operator shall be entitled to invest the amount of Settlement Guarantee Cover in approved securities and/or other avenues of investments in accordance with the mechanism as may be approved by the MO Board of Directors and approved by the Authority in the market operator fee determination. The Market Operator shall ensure that while depositing these amounts in alternative securities, the principal amount is not left at risk and shall limit such investments to risk free securities, interest bearing accounts, saving accounts etc. Any returns on such investment will be retained in in the Settlement Guarantee Cover Account and will be utilized in the event of default. Upon withdrawal of a Market Participant, only the principal amount deposited by such Market Participant, duly adjusted for any defaults during the previous period, will be returned to it.

13.1.3.6. The Market Operator shall continuously monitor the sufficiency of the Security Cover Amounts and Guarantee Cover Amount and shall be entitled to increase/decrease it.

13.1.3.7. The Market Operator shall also monitor Imbalance exposure on daily basis as follows:

a) if the expected Amount Payable on account of Imbalances of a Market Participant exceeds by 50% of its Security Cover, a notice shall be sent to the said Market Participant to this effect;

b) if the expected Amount Payable on account of Imbalances of a Market Participant exceeds by 70 % of its Security Cover, second notice will be sent to the said Market Participant to this effect;

c) if the expected Amount Payable on account of Imbalance any day before the end of the month exceeds by 80 % of its Security Cover, the Market Operator shall require the said Market Participant for submission of additional Security Cover, as determined by the Market Operator, against its expected Imbalances till the end of the month.

13.1.3.8. The Market Participant shall submit the amount of additional Security Cover by three (03) Business Days of the issuance of the requirement by the Market Operator.

13.1.3.9. Where a Market Participant fails to deposit additional Security Cover amount within the specified time period, it shall be considered as an Event of Default and shall be dealt with in accordance with the provisions of Chapter 16 of this Code.

13.1.3.10. Till the time the CCOP is prepared as per Clause 13.1.3.1, the Market Operator shall determine the revised amounts as under:

a) on rolling basis, if the average amount to be paid by a Market Participant as per previous three (3) monthly Settlement Statements is higher than the amount deposited as Security Cover by such Market Participant, the Security Cover Amount requirement of such Market Participant shall be increased to the maximum Amount Payable during the same period. Further, the Settlement Guarantee Amount shall also be increased accordingly;

b) if the average amount to be paid by a Market Participant as per previous twelve (12) monthly Settlement Statements is lower than the amount deposited as Security Cover by such Market Participant, the Security Cover Amount requirement of such Market Participant will be decreased to the maximum Amount Payable during the same period which shall not be lower than (Rs. 1.5) Millions. Further, the Guarantee Amount shall also be decreased accordingly.

13.1.3.11. The Market Operator shall inform the respective Market Participants whose Security Cover Amount and/or Guarantee Amount requirement has been increased along with reasons thereof. The Market Participants shall deposit with the Market Operator such amount of Security Cover and/or Guarantee Amount as required by the Market Operator within the specified time.

13.1.3.12. In case of decrease in the Security Cover Amount of the Market Participant as per Clause 13.1.3.10.b), the Market Operator shall inform the respective Market Participant of such decrease and stating whether such amount will be paid to it or the same will be adjusted in its settlements being done by the Market Operator.

13.2. SECURITY COVER FOR MONTHLY SETTLEMENTS

13.2.1. SECURITY COVER REQUIRED DURING ENROLMENT AS MARKET PARTICIPANT

13.2.1.1. The amount of the Security Cover which shall be provided by a Market Participant pursuant Clause 2.3.4.1 shall be determined according to the Category for which the application has been made which are described below:

a) for enrolment as BPC, Electric Power Supplier or Electric Power Trader, no Security Cover shall be required;

b) for enrolment as a Generation Company or Captive Generator, the amount of the Security Cover shall be determined on the basis of its expected consumption from the network in one month if this back-feed Energy is not already contracted from another Market Participant. This value shall be calculated as 5 percent of its Dependable Capacity (expressed in kW) multiplied by the 720 hours and multiplied by six (6) PKR/kWh;

c) When a Market Participant registers a new Contract, the amount of the Security Cover provided during the enrolment process shall be adjusted accordingly.

13.2.2. SECURITY COVER FOR LEGACY CONTRACTS-CPPA-G

13.2.2.1. Market Participants which are purchasing Energy and Capacity through Legacy Contracts-CPPA-G shall provide to the Market Operator an initial Security Cover, as provided in Clause 13.1.3.2.

13.2.3. SECURITY COVER FOR NEW CONTRACTS

13.2.3.1. The Market Operator shall determine the amount of the Security Cover to be provided by each Market Participant prior to registration of a Contract, which shall be maintained until a new or different amount is determined. The Security Cover to be provided by a Market Participant shall cover the obligations of the Market Participant arising under the Contract being registered, plus its obligations associated with any other Contract already registered with the Market Operator.

13.2.3.2. The amount of the Security Cover that shall be provided pursuant to Clause 13.2.3.1 above, shall be determined by estimating the expected payments from such Market Participant, towards the purchase of Energy from the Balancing Mechanism for Energy, plus the payments for the Ancillary Services, Transmission Must Run and Reliability Must Run, the Market Operator fee and, if applicable, the System Operator fee, for the following Energy Settlement Period. The CCOP prepared under Clause 13.1.3.1 shall include mechanisms for determining the amount of the Security Cover and the Guarantee Amount to be provided by each Market Participant at the time of registration of a new Contract.

13.2.4. DEPOSIT AND VERIFICATION OF THE SECURITY COVER, SETTLEMENT GUARANTEE COVER

13.2.4.1. After depositing the Security Cover and Settlement Guarantee Cover in the respective bank accounts of the Market Operator, the concerned Market Participant shall immediately inform the Market Operator along with the relevant documents.

13.2.4.2. The Market Operator shall review the submitted documents to verify whether the Security Cover and Settlement Guarantee Cover amounts are equal or above the amount calculated by the Market Operator.

13.2.4.3. In the case the deposited amounts are equal or above the amounts as determined by the Market Operator, the Market Operator shall acknowledge the acceptance thereof and shall proceed to enrol the person as Market Participant or register the Contract, as the case may be.

13.2.4.4. In case the Market Operator considers that the Security Cover or the Guarantee Amount is deficient, it shall require the Applicant or Market Participant to provide the Security Cover or the Guarantee Amount according to the requirements.

13.3. <u>ADVANCE INSTALMENT FOR YEARLY SETTLEMENTS</u>

13.3.1. ADVANCE INSTALMENTS REQUIRED FOR PARTICIPATION IN THE BMC

13.3.1.1. A Market Participant having negative Capacity Balance, calculated pursuant to Clause 9.2.5.1, shall submit Advance Instalment for an amount as determined by the Market Operator in accordance with Clause 9.5.1.1.

13.3.2. DEPOSIT AND VERIFICATION OF THE ADVANCE INSTALMENT

13.3.2.1. After depositing the Advance Instalment in the Market Operator Security Cover Account, the concerned Market Participant shall immediately inform the Market Operator along with the relevant documents.

13.3.2.2. The Market Operator shall review the submitted documents to verify whether the amount of the Advance Instalment is equal or above the amount notified by the Market Operator pursuant to Clause 9.5.1.1;

13.3.2.3. In the case the Advance Instalment is sufficient, the Market Operator shall acknowledge the acceptance thereof and the Market Participant shall be included in the execution of the Balancing Mechanism for Capacity. In case the Market Operator considers that the Advance Instalment provided is deficient, the provision of Clause 9.6.1.2 shall apply.

13.3.3. MAINTENANCE OF THE SECURITY COVER REGISTER

13.3.3.1. The Market Operator shall organize and maintain a register for the Security Cover and Advance Instalments provided by all Market Participants.

13.3.3.2. The following information shall be included in the Security Cover Register:

a) the identification of each Market Participant;

b) the amount of the Security Cover and Advance Instalment provided by each Market Participant;

c) the purpose for which the Security Cover or the Advance Instalment is provided (enrolment as Market Participant, monthly Settlements or yearly Settlements).

13.3.3.3. The Market Operator shall update the Security Covers Register when:

a) the Market Participant provides a new Security Cover or Advance Instalment, or it modifies the amounts submitted;

b) a Security Cover or Advance Instalment is totally or partially used;

c) a Market Participant withdraws/terminates its enrolment as Market Participant and its Security Cover is returned; or

d) any excess amount of a Market Participant is returned.

13.4. UTILIZATION /REVISION/CANCELLATION OF THE SECURITY COVERS OR ADVANCE INSTALMENT

13.4.1. SECURITY COVER UTILIZATION IN CASE OF MONTHLY SETTLEMENTS

13.4.1.1. On the Clearing Day, the Market Operator shall utilize or make necessary payments from the Security Cover of a Market Participant on account of Amounts Payable by such Market Participant.

13.4.1.2. Upon utilization of the Security Cover to pay the Amounts Payable as per the monthly Settlement Statement, the Market Operator shall issue a Debit Advice to inform the concerned Market Participant clearly indicating the amount that has been utilized and needs to be replenished.

13.4.2. SECURITY COVER REVISION

13.4.2.1. The Market Operator shall issue a Debit Advice to the concerned Market Participant to provide additional Security Cover, if required, as a result of periodic revision pursuant to Clause 13.1.3.10.

13.4.3. FAILURE TO PROVIDE SECURITY COVER

13.4.3.1. Failure to replenish the utilized Security Cover as per Clause 13.4.1.2 and/or revised Security Cover, as per Clause 13.4.1.2, shall be considered as an Event of Default of the concerned Market Participant, pursuant to Sub-Section 16.2.1.

13.4.4. ADVANCE INSTALMENT UTILIZATION IN CASE OF YEARLY SETTLEMENTS

13.4.4.1. After utilization of the Advance Instalment of a Market Participant to satisfy its payment obligations under a yearly Settlement Statement, the Market Operator shall:

a) inform the involved Market Participant about the utilization of first instalment of the Advance Instalment, clearly indicating the amount utilized;

b) Issue a Debit Advice to the concerned Market Participant to provide the Market Operator the Advance Instalment for the next payment, calculated pursuant to Clause 9.5.1.1, within five (5) Business Days of the date of issuance of such Debit Advice.

13.4.4.2. Failure to comply with the requirement of Clause 13.4.4.1.b) shall be considered as an Event of Default of the concerned Market Participant, pursuant to Sub-Section 16.2.1.

13.4.5. ADJUSTMENT AND RETURN OF A SECURITY COVER

13.4.5.1. Non-utilized Security Cover may be returned or adjusted, in the following cases:

a) The Security Cover may be returned if the enrolment of a Market Participant is withdrawn or revoked after following the procedure as set forth in Section 2.5;

b) Where a Market Participant deregisters a Contract, pursuant to Section 3.6, the amount of the required Security Cover shall be recalculated by the Market Operator. If the recalculated amount is lower than the Security Cover already provided by the Market Participant, the Market Participant may decide to:

b.1. maintain the existing Security Cover for future transactions; or

b.2. request the Market Operator to return the excess amount of the Security Cover.

13.4.5.2. The Market Operator may return the excess amount upon request of the relevant Market Participant.

13.4.6. WITHDRAWAL/TERMINATION OF A MARKET PARTICIPANT BEFORE END OF A SETTLEMENT PERIOD

13.4.6.1. Where a Market Participant withdraws its enrolment or is terminated by the Market Operator, the Market Operator may withhold its Security Cover or Settlement Guarantee Cover amount in full or a portion thereof, if it considers that there are charges to be calculated in future for the upcoming monthly and yearly Settlement Statements which may be payable by such Market Participant.

13.4.7. RETURN OF A PRINCIPAL AMOUNT OF SETTLEMENT GUARANTEE COVER

13.4.7.1. The principal amount deposited by a Market Participant may be returned if the enrolment of a Market Participant is withdrawn or revoked after following the procedure as provided in section 2.5.

13.4.7.2. While calculating the amount to be returned to the Market Participant pursuant to Clause 13.4.7.1 above, the Market Operator shall take into account any default in the Market which was covered through utilization of the Settlement Guarantee Cover. Any amount that was used from such Market Participant to cover the default in the Market shall be deducted from the amount deposited by such Market Participant.

13.4.8. ADJUSTMENT OF THE AMOUNT OF SETTLEMENT GUARANTEE COVER

13.4.8.1. Each year, the Market Operator shall review the adequacy of the amount deposited in the Settlement Guarantee Cover Account to cover the payment obligations of the Market Participants.

13.4.8.2. The Market Operator shall prepare a report on the adequacy of the amounts deposited by Market Participants in the Settlement Guarantee Cover Account and submit the same to the Authority along with recommendations to adjust the amounts being deposited in the Settlement Guarantee Cover Account.

Chapter 14. SETTLEMENT OF DISPUTES

14.1. APPLICATION

14.1.1.1. The Dispute resolution procedure stipulated in this Chapter shall apply to:

a) any Dispute between the Market Operator and the System Operator, or the Market Operator with a Service Provider or any Market Participant, which arises under or in connection with or in relation to provisions of this Code;

b) a Dispute between a Market Participant and a Metering Service Provider or a Dispute between a Market Participant or the System Operator which arises under or in connection with or in relation to provisions of this Code;

c) any order of rejection by the Market Operator to enrol a person as a Market Participant or Service Provider, or to register a Contract;

d) a dispute under this Code between the Market Operator and a Service Providers or a Market Participant regarding the terms and conditions or interpretation of the Market Participation Agreement or the Service Provider Agreement.

14.1.1.2. The dispute resolution process shall not apply to the following:

a) a dispute arising under a Bilateral Contract between the Market Participants or any other dispute which is not related to the implementation of the provisions of this Code;

b) any dispute relating to, connected with or arising out of an application by any person to amend a Clause or condition of this Code or a Dispute relating to validity of an Amendment to this Code;

c) disputes with respect to a proposal to amend or not to amend any provision of this Code;

d) disputes between the Market Operator and a Market Participant relating to the rate of the Market Operator fee as approved by the Authority and chargeable by the Market Operator to the Market Participant, unless the dispute relates to or is connected with the manner of calculation of the Market Operator charge payable by the Market Participant in any given case; and

e) the functions performed by the Market Operator under Chapter 15 of this Code.

14.1.1.3. Without limiting the generality of the foregoing, where any Dispute arises and the parties have commenced proceedings under this Chapter, the concerned parties shall comply with the procedures set forth in this Chapter and shall not make such Dispute a subject matter of any civil or other proceedings.

14.1.1.4. Any Dispute shall be lodged only within one (1) year of the occurrence thereof and no Dispute shall be entertained after expiry of this time period and the Notice of Dispute shall be rejected.

14.2. CONTINUING OBLIGATIONS AND STAY OF ORDERS

14.2.1.1. Where a Dispute involves the payment or recovery of monetary amounts due under this Code, other than payment of a financial penalty, the amount shall be due and payable at the time specified for payment, notwithstanding initiation of a dispute resolution process whether under this Code or otherwise.

14.2.1.2. Where a Dispute involves the implementation of an order made or a direction given by the Market Operator under Chapter 16, the obligation of the Market Participant to comply with the order or direction, may be stayed for such period not exceeding thirty (30) days, if any, as may be determined by the Adjudicator or the Authority, provided that such stay shall not be granted except where the concerned Market Participant has made the requisite payment to the Market Operator as required under an order or direction of the Market Operator.

14.3. PROCEDURE FOR SETTLEMENT OF A DISPUTE

14.3.1. NOTICE OF DISPUTE

14.3.1.1. Subject to Clause 14.1.1.2, any person feeling aggrieved or any other person who wishes to settle a matter under this Chapter shall submit to the Market Operator or the System Operator or the Metering Service Provider, as the case may be, a written "Notice of Dispute" clearly explaining the Dispute or the grievance along with all necessary supporting documents.

14.3.1.2. The Market Operator or the System Operator or the Metering Service Provider, as the case may be, shall acknowledge the receipt of the Notice of Dispute and review its completeness. The party to which the Notice of Dispute was issued may require the party issuing the Notice of Dispute to submit further information or additional documents, which shall be provided within the specified time.

14.3.2. AMICABLE RESOLUTION

14.3.2.1. Within twenty (20) Business Days of the receipt of the Notice of Dispute or the additional information or documents, as the case may be, the Market Operator or the System Operator or the Metering Service Provider, as the case may be, and the party who issued the Notice of Dispute, shall make good faith efforts to negotiate and resolve the Dispute. The Market Operator or the System Operator or the Metering Service Provider, as the case may be, and the other party to the Dispute shall designate a senior officer from their respective organizations, with the authority to negotiate the matter set out in the Notice of Dispute.

14.3.2.2. For the disputes related to the Market Operator, for application of the provisions of Clause 14.3.2.1, the Market Operator may constitute different committees of its officers and each committee will commence negotiations based on the nature of the Dispute and will prepare a report upon completion of the negotiations.

14.3.2.3. Upon successful negotiations, the Market Operator or the System Operator or the Metering Service Provider, as the case may be, shall issue a notice of termination of the Dispute.

14.3.2.4. Disputes between the Market Operator and System Operator or a Service Provider on matters related to the Market and this Code that fail an amicable resolution shall be submitted to the Authority for decision.

14.3.3. SOLE EXPERT

14.3.3.1. Failing an amicable settlement of the Dispute under Sub-Section 14.3.2, within a reasonable period of time, the same may be referred, by mutual agreement of the parties to the Dispute, to a sole expert. The sole expert shall be an independent and impartial person with relevant qualifications and experience and shall be appointed by agreement between the parties to the Dispute and who shall not, by virtue of personal connection or commercial interest, have a conflict between his own interest and his duty as a sole expert.

14.3.3.2. The Market Operator shall publish on its website a list of credible professionals having relevant qualification and experience which may be selected with mutual consent of the parties to perform the duties of the sole expert. Such list may be updated from time to time.

14.3.3.3. In the event, that the parties to the Dispute fail or are unable to agree on a sole expert within thirty (30) days or such longer period as may be mutually agreed by such parties, the sole expert shall be appointed by a body or an institution or an agency or a person, mutually agreed by such parties. In case, there is no agreement on the body or an institution or an agency or a person for appointing sole expert or such institution or agency or body fails to appoint a sole expert within thirty (30) days or such longer period as may be mutually agreed by such parties, the matter shall be referred to the Authority as provided under Sub-Section 14.3.4 below.

14.3.3.4. Any sole expert appointed shall be acting as an expert and not act as an adjudicator or arbitrator and the decision of the sole expert if not accepted by a party shall be subject to appeal before the Authority as provided below within ninety (90) days thereof.

14.3.3.5. The sole expert and representatives of the disputing parties, with authority to settle the dispute, shall within fourteen (14) days after the date of appointment of the sole expert schedule a date to resolve the dispute. Matters discussed during such hearing shall be kept confidential and shall not be referred to in any subsequent proceedings.

14.3.3.6. If any party to the Dispute does not agree with the determination of the sole expert, the matter shall be referred to the Authority as provided under Sub-Section 14.3.4 below.

14.3.3.7. If all parties to the Dispute agree with the determination of the sole expert, the Market Operator or the System Operator or the Metering Service Provider, as the case may be, shall issue a notice of termination of the Dispute.

14.3.4. THE AUTHORITY

14.3.4.1. Any Dispute that could not be resolved according to the provisions of Sub-Section 14.3.2 and 14.3.3 above, may be referred to the Authority or a tribunal constituted by the Authority for this purpose.

14.3.5. CONFIDENTIALITY

14.3.5.1. Any party may claim that a document, or information contained in a document, to be produced in the context of the adjudication of a Dispute is Confidential Information. The party making such a claim shall provide to the tribunal in writing the basis for its assertion. If the claim of confidentiality is confirmed by the tribunal, the Adjudication Tribunal shall establish requirements for the protection of such document or information as may be necessary to protect the confidentiality and commercial value of such document or information, including requirements for disclosure of same only to the tribunal or independent advisor who has filed an undertaking as to confidentiality satisfactory to the tribunal and for in camera hearings at which only representatives of the disclosing party and such counsel and/or other independent advisor may be present.

14.3.6. RECORD-KEEPING AND PUBLICATION

14.3.6.1. The Market Operator or the System Operator or the Metering Service Provider, as the case may be, shall maintain a record of all dispute resolution proceedings conducted and shall be responsible for ensuring that all measures are taken to prohibit access by any other person to any portion of such record which may be sealed and marked "CONFIDENTIAL" or otherwise identified as being confidential, except as may be required by Applicable Law.

14.3.6.2. The Market Operator or the System Operator or the Metering Service Provider, as the case may be, may arrange publication of the following information on its website:

a) notice of the appointment of the sole expert or the Adjudication Tribunal;

b) notice of the date, time and place fixed for hearing; and

c) a summary of the decision of the Authority/Adjudication Tribunal.

14.3.7. COSTS AND FEES

14.3.7.1. Each party to the Dispute shall bear its own costs incurred for the dispute resolution process. Initially, the fees of the sole expert shall be borne on pro rata basis by the parties, however, in the decision, the sole expert shall decide which party have to bear the costs of the dispute resolution. If the decision is referred to the Authority or the Adjudication Tribunal, the final decision of the Authority or the Adjudication Tribunal shall prevail with regard to the costs and fees.

Chapter 15. MARKET DEVELOPMENT AND ASSESSMENT

15.1. MARKET DEVELOPMENT AND EVOLUTION

15.1.1. REVIEW OF LEGAL, POLICY AND REGULATORY FRAMEWORK

15.1.1.1. While implementing the Commercial Code, the Market Operator shall continuously review the overarching legal, policy and regulatory framework and propose recommendations to the competent authorities to enhance the efficiency of the Market. The Market Operator shall also abide by all the applicable legal instruments.

15.1.2. PRODUCT DESIGN AND MARKET EVOLUTION

15.1.2.1. The Market Operator shall recommend for the approval of Authority, any modifications in the design of the CTBCM, introduction of new products such as Ancillary Services market, day-ahead market, trading platforms etc.

15.1.2.2. The Market Operator shall be responsible to undertake the necessary research to enable the advanced features of competitive electricity markets by duly considering the maturity of the CTBCM.

15.1.3. INTERNATIONAL AFFAIRS

15.1.3.1. The Market Operator may actively engage with international organizations involved in development and operation of the competitive electricity markets and may form strategic partnerships with such organizations in order to learn from their experience to enhance the efficiency of CTBCM.

15.1.4. LIAISON WITH STAKEHOLDERS AND MARKET TRAININGS

15.1.4.1. The Market Operator may actively engage with all the stakeholders for development of the competitive market and shall organize training and capacity building sessions pertaining to all areas relevant for the development and efficient operations of the competitive market in order to disseminate information among all stakeholders.

15.1.4.2. The Market Operator shall prepare a training plan based on the needs of different stakeholders and shall conduct the identified trainings as per the plan.

15.1.5. MARKET SIMULATIONS AND ANALYSIS

15.1.5.1. The Market Operator shall produce projections for future years about the results of the Market in order to give future perspectives to stakeholders.

15.1.5.2. The projections being carried out by the Market Operator shall be based on best estimates; however, the Market Operator shall not be held liable for any loss due to use of such projections in the decision making by the stakeholders.

15.2. MARKET ASSESSMENTS

15.2.1. MARKET ASSESSMENT FUNCTION

15.2.1.1. The Market Operator shall assess the impacts of any activity related to the CTBCM or the conduct of a Market Participant, and thereafter prepare and submit reports to the Authority. In doing so, the Market Operator shall:

a) assess the impacts of the behaviour of the Market Participants including withholding of Capacity or manipulation of costs, abuse or possible abuse of market power;

b) assess and observe the implementation of this Code as well as the market design in consultation with the stakeholders, to identify and propose measures as early as possible to address any flaws or difficulties faced by parties operating in the Market;

c) provide input during the amendments to this Code; and

d) assess the pace of development of competition and market efficiency.

15.2.1.2. The Market Operator may engage consultants with expertise in collecting and analysing the information pertaining to the market behaviour of the Market Participants.

15.2.2. REPORTING

15.2.2.1. The Market Operator shall prepare reports upon completion of any assessment and take such steps as may be necessary that may include:

a) Issuance of warning letters to Market Participants involved in anti-competitive behaviours;

b) Submission of recommendations to the Authority including any recommendation for taking punitive action if the behaviour of a Market Participant is of such nature that involves breach of terms and conditions of a License or other rules and regulations of the Authority;

c) Submission of recommendations to the Authority regarding improvements in the market design to enhance efficiency and competition; or

d) Submission of recommendations to CCRP if the assessment requires any amendment to this Code.

15.2.3. MARKET ASSESSMENT PROCEDURE

15.2.3.1. The Market Operator shall monitor, evaluate and analyse the conduct of Market Participants related to the Market and this Code and the structure and performance of, and activities in, the CTBCM including, but not limited to:

a) inappropriate or anomalous market conduct, including unilateral or interdependent behaviour resulting in manipulation, abuse or possible abuse of market power;

b) identify actual or potential design flaws or procedural inefficiencies in this Code or in the Commercial Code Operational Procedures;

c) actual or potential design flaws in the overall structure of the CTBCM and assess whether any one or more specific aspects of the underlying structure of the CTBCM is consistent with the efficient and fair operation of a competitive market; and

d) such other matters as the Market Operator deems appropriate.

15.2.3.2. The Market Operator shall develop a system for gathering information as well as criteria for evaluation of the information to enable it to effectively carry out the monitoring functions. For this purpose, the Market Operator shall develop and publish on MO Website:

a) a detailed catalogue of data and/or categories of data it requires from Market Participants, the System Operator and relevant Service Providers; and

b) a catalogue of the monitoring indicators that it will use to evaluate and analyse the data so acquired.

15.2.3.3. The Market Operator shall establish procedures for handling the acquired data including procedures for protecting Confidential Information.

15.2.3.4. The Market Operator shall not disclose, to any person, Confidential Information pertaining to any other person and acquired for the purpose of carrying out its monitoring functions.

15.2.3.5. Market Participants, Service Providers and the System Operator shall provide to the Market Operator the data referred to in the catalogue described in Clause 15.2.3.2.a) once published by the Market Operator.

15.2.3.6. The catalogues in Clauses 15.2.3.2.a) shall be subject to such re-evaluation and refinement by the Market Operator as deemed appropriate.

15.2.3.7. The Market Operator shall, no less than annually and more frequently prepare routine reports on matters pertaining to its responsibilities pursuant to this Chapter, including a summary of all complaints or referrals filed and assessments commenced under Clause 15.2.3.1. Such reports shall contain the Market Operator's general assessment as to the state of competition within, and the efficiency of, the CTBCM.

15.2.3.8. The Market Operator may, from time to time, if required, consult the Market Participants regarding the activities identified in Section 15.2, provided however, that no Confidential Information shall be disclosed to any Market Participant without prior concurrence of the concerned Market Participant to whom such Confidential Information belongs in accordance with the applicable regulations of the Authority including the NEPRA Licensing (Market Operator) Regulations, 2022.

15.2.3.9. The Market Operator shall prepare a report if it, while carrying out its duties, identifies in matters related to the Market and this Code that:

a) that a Market Participant is or may be breaching or violating a provision of this Code; or

b) that an Amendment to this Code may be required;

15.2.3.10. if the report prepared pursuant to Clause 15.2.3.9above, recommends that an Amendment to this Code may be made, a copy of such report shall be sent to the Commercial Code Review Panel. If such report identifies that a breach is committed or that might have been committed by a Market Participant, a copy of such report shall be sent to the concerned Market Participant as well.

15.2.4. Dispute Resolution and Other Relief

15.2.4.1. The dispute resolution procedures under Chapter 14 shall not apply to the activities carried out by the Market Operator under this Chapter.

15.2.5. PUBLICATION AND PROVISION OF DATA

15.2.5.1. Any interested party may request the Market Operator to provide data, which is not Confidential Information collected or created in the course of the Market which is not otherwise required to be published by the Market Operator. Such data may be provided unless, a justification is provided by the Market Operator that such disclosure is reasonably likely to compromise the work of the Market Operator.

Chapter 16. ENFORCEMENT OF COMMERCIAL CODE

16.1. COMPLIANCE AND BREACHES

16.1.1. COMPLIANCE

16.1.1.1. The Market Operator, System Operator, Service Providers and all Market Participants shall comply with this Code as applicable.

16.1.1.2. The Market Operator shall monitor compliance with the provisions of this Code, as applicable, by all Market Participants and Service Providers.

16.1.1.3. Any Market Participant or a Service Provider which has evidence that another Market Participant or a Service Provider has violated or is violating the provisions of this Code, shall inform the Market Operator immediately along with all supporting documents.

16.1.2. PROCEDURE CONCERNING ALLEGED BREACHES OF THIS CODE

16.1.2.1. Where this Code provides for consequences or penalties in respect of a breach of a particular Clause or provision by a Market Participant or Service Provider, those consequences or penalties shall apply in the circumstances and in the manner provided for in the relevant Clauses or provisions, in addition to any other penalties as may be imposed pursuant to Sub-Section 16.3.1.

16.1.2.2. In case the Market Operator considers, on the basis of its own information or upon receipt of written information from any person, that a Market Participant may have breached or may be breaching any provision of this Code, other than a breach constituting an Event of Default under Sub-Section 16.2.1, and it is appropriate that an enforcement action may be taken against that Market Participant, the Market Operator shall issue a notice, with a copy to the Authority, to the relevant Market Participant requiring it to provide the necessary explanation regarding the alleged breach.

16.1.2.3. The Market Participant shall submit the required explanation to the Market Operator within specified time and, if required, request for a representation before the Market Operator to present its case.

16.1.2.4. Upon review of the submitted explanation and, if applicable, consideration of arguments presented during the representation, the Market Operator may issue a show cause notice, with a copy to the Authority, to the relevant Market Participant specifying the following:

a) the alleged breach and the time within which the breach must be remedied;

b) the relevant evidence or information available with the Market Operator;

c) the remedial actions that will be taken if the breach is not remedied;

d) the time within which the Market Participant may submit written response;

e) the right of the Market Participant to request for a representation before the Market Operator to discuss the matter.

16.1.2.5. Where the Market Participant has requested a meeting pursuant to Clause 16.1.2.4.e), the Market Operator shall provide the Market Participant with a reasonable opportunity to present its case.

16.1.2.6. After expiry of the time specified in the notice and consideration of the response, if any, and holding of the meeting, if requested, the Market Operator may:

a) determine that the Market Participant has not breached this Code;

b) determine that the Market Participant is in breach of this Code;

c) require that the Market Participant provide further information regarding the alleged breach; or

d) conduct such further assessment into the matter as the Market Operator may deem appropriate.

16.1.2.7. Where the Market Operator determines that a Market Participant has breached this Code, the Market Operator may require such Market Participant, to do any one or more of the following:

a) direct the Market Participant to take, within a specified period, such actions as may be necessary to comply with this Code;

b) direct the Market Participant to cease, within a specified period, the act, activity or practice constituting the breach;

c) impose additional or more stringent record-keeping or reporting requirements on the Market Participant;

d) issue a non-compliance letter in accordance with Sub-Section 16.3;

e) take any remedial actions as per Market Participation Agreement; or

f) take such other action as may be provided for in this Code in respect of the provisions that have been breached by the Market Participant.

16.1.2.8. A Market Participant shall comply with an order of the Market Operator made pursuant to Clause 16.1.2.7 as soon as the order is received by the Market Participant.

16.2. <u>Suspension and Termination Orders</u>

16.2.1. Events of Default

16.2.1.1. Each of the following shall constitute as an Event of Default for a Market Participant:

a) the Market Participant fails to comply with an order of the Market Operator made pursuant to Clause 16.1.2.7 once the order has become effective;

b) the Market Participant fails to comply with the decision of the Sole Expert or Adjudication Tribunal or the Authority under Chapter 14 unless such decision has been stayed;

c) the Market Participant does not pay the required amount in full under a Security Cover or Settlement Guarantee Cover or Advance Instalment within one (1) Business Day after the Payment Due Date;

d) it becomes unlawful for the Market Participant to comply with any of its obligations under this Code, or any other obligation owed to the Market Operator or it is claimed to have become so by the Market Participant;

e) a licence, including a Licence issued by the Authority pursuant to the Act, permit or other authorization necessary to enable the Market Participant to conduct its business or activities is suspended, revoked or otherwise ceases to be in full force and effect, provided that where a Market Participant holds more than one licence and only one such licence has been suspended, revoked or otherwise ceases to be in full force and effect, the Event of Default and any action taken by the Market Operator with respect thereto shall relate only to such licence;

f) the Authority informs the Market Operator that procedures have been initiated that it may revoke the License of the Market Participant;

g) the Market Participant enters into or takes any action to enter into an arrangement, composition or compromise with, or an assignment for the benefit of, all or any class of their respective creditors or members, or a moratorium involving any of them;

h) the Market Participant states that it is unable to pay from its own money its debts when they fall due for payment;

i) a receiver or an administrator is appointed in respect of any property of the Market Participant which is used in or relevant to the performance by the Market Participant of its obligations under this Code;

j) an administrator, liquidator, trustee in bankruptcy or person having a similar or analogous function under the laws of any relevant jurisdiction is appointed in respect of the Market Participant, or any action is taken to appoint such person;

k) an application is made for the winding up or dissolution or a resolution is passed or any steps are taken to pass a resolution for the winding up or dissolution of the Market Participant;

l) the Market Participant is wound up or dissolved, unless the notice of winding up or dissolution is discharged;

m) the Market Participant is taken to be insolvent or unable to pay its debts under any applicable legislation;

n) the Market Participant ceases to satisfy any material requirement imposed upon it as a condition of its enrolment to participate in the CTBCM;

o) the Market Participant fails to inform the Market Operator of a material change in the information required under its Admission Application pursuant to Sub-Section 2.3.2; or

p) the Market Participant persistently commits breach of this Code or the Grid Code; or

q) any other event, circumstances or situation that has been considered as an Event of Default by the provisions of this Code.

16.2.1.2. A Market Participant shall inform the Market Operator immediately upon becoming aware of any circumstance that may give rise to or of the occurrence of an Event of Default.

16.2.1.3. Where a Market Participant is involved in an Event of Default, the Market Operator may:

a) issue to the concerned Market Participant a Default Notice specifying the alleged default and requiring the Market Participant to remedy the default within such time as may be specified in the Default Notice, which time shall not be more than two (2) Business Days; and/or

b) call on the Security Cover of the concerned Market Participant and recover such amount as the Market Operator determines appropriate that represents the amount of any money which is actually payable by the concerned Market Participant to the Market

Operator or any of its contingent liabilities towards the Market Operator under this Code; or

c) issue a Default Notice to concerned Market Participant for explanation of the Event of Default within twenty four (24)hours and if no satisfactory response is received, issue the Suspension Order and a request for temporary or permanent disconnection, as the case may be, to the System Operator (if required) and the relevant Transmission or Distribution Licensee, if:

c.1. the Event of Default relates to default in making payment by the Market Participant; or

c.2. the matter is of such nature that requires urgent action.

16.2.1.4. For issuance of the Suspension Order and request for temporary or permanent disconnection pursuant to Clause 16.2.1.3.c), the provisions of Sub-Section 16.2.2 shall, not apply.

16.2.1.5. Where the Market Operator issues a Default Notice to a Market Participant, the Market Operator shall also inform the Authority and the Transmission or Distribution Network Service Provider, where the Market Participant is connected:

a) about the issuance of the Default Notice;

b) about the time within which the Market Participant is required to remedy the default as specified in the Default Notice.

16.2.1.6. Once the default has been remedied by the Market Participant, the Market Operator shall inform the Authority, the relevant Transmission or Distribution Network Service Provider, if required.

16.2.1.7. A Market Participant may remedy an Event of Default, where the Default Notice relates to payment of amounts due to the Market Operator under this Code, including Clauses 16.2.1.1.b) to 16.2.1.1.d) and 16.2.1.1.g) to 16.2.1.1.m), as follows:

a) by paying all Amounts Payable under this Code, together with any Default Interest in accordance with any Debit Advice issued by the Market Operator and any costs and expenses determined by the Market Operator to have been incurred by it by reason of the default; and

b) by providing additional Security Cover or Advance Instalment which complies with the requirements of Chapter 13.

16.2.1.8. Notwithstanding that the Event of Default may have been remedied by the Market Participant, the Market Operator may, where it considers that it is in the interest of preserving the integrity of the CTBCM, impose such conditions on the participation of a Market Participant in the Energy or Capacity Balancing Mechanisms as deemed appropriate.

16.2.2. SUSPENSION ORDERS

16.2.2.1. If an Event of Default is not remedied within the time specified in the Default Notice or within such longer period as may be allowed by the Market Operator in writing, a notice of intention indicating the following may be issued by the Market Operator:

a) a Suspension Order to the Market Participant suspending or restricting all or any of the Market Participant's rights to participate in the CTBCM; and/or

b) a request to the System Operator (if required) and the relevant Transmission or

Distribution Network Service Provider, requesting the temporary or permanent disconnection, as the case may be, of the relevant Facilities or equipment of the Market Participant.

16.2.2.2. The Market Operator shall provide a copy of the notice issued pursuant to Clause 16.2.2.1 to the relevant Transmission or Distribution Network Service Provider.

16.2.2.3. Upon receipt of the notice issued pursuant to Clause 16.2.2.1, the concerned Market Participant shall have the right to request, within 2 Business Days, a meeting with the Market Operator to justify that the Suspension Order, the request for disconnect, or both, as the case may be, shall not be issued.

16.2.2.4. Where the Market Participant:

a) has not requested a meeting pursuant to Clause16.2.2.3, or has notified the Market Operator that it does not intend to request such a meeting; or

b) has requested a meeting, then upon conclusion of a meeting, the Market Operator may:

b.1. issue a Suspension Order to the Market Participant suspending or restricting all or any of the Market Participant's rights to participate in the CTBCM; and/or

b.2. if considered appropriate, issue, with a copy to the Market Participant and the Authority, a request for disconnection to the System Operator (if required) and the relevant Transmission or Distribution Network Service Provider requesting temporary or permanent disconnection, as the case may be, of the relevant Facilities or equipment of the Suspended Market Participant from the Transmission Network or the Distribution Network as the case may be; and/or

b.3. make such other order with due justification for remedial actions regarding the default.

16.2.2.5. Where the Market Participant has requested a meeting pursuant to Clause 16.2.2.3, the Market Operator, within ten (10) Business Days of the date of receipt of such request, shall hold a meeting providing the Market Participant with a reasonable opportunity to justify that why the Suspension Order, the request for disconnection or both should not be issued against it. In such circumstances, the Market Operator shall not issue either the Suspension Order or the disconnection request until such meeting has been held.

16.2.2.6. The Market Operator may withdraw a Suspension Order if the Event of Default, which caused issuance of the Suspension Order, is remedied and there are no outstanding Events of Default with respect to the Suspended Market Participant, provided that the Market Operator may, as a condition of withdrawing a Suspension Order, impose such conditions on the Market Participant to participate in the CTBCM, as deemed appropriate, including:

a) establishing a lower buying and selling limit for the Market Participant than would otherwise be the case under this Code;

b) establishing a more frequent and continuing schedule of payments than would otherwise be the case under this Code; or

c) imposing more stringent Security Cover requirement than would otherwise be the case under Chapter 13.

16.2.2.7. Following the issuance of a Suspension Order to a Market Participant, the Market Operator may do one or more of the following to give effect to the Suspension Order:

a) reject registering any new Contract submitted by the Suspended Market Participant or suspend its existing Contracts registered with the Market Operator;

b) withhold the payment of any amounts to the Suspended Market Participant under this Code;

c) make such further order or issue such directions to the Suspended Market Participant with adequate justification for enforcement of the Suspension Order.

16.2.2.8. Upon receipt of the disconnection request from the Market Operator, the System Operator shall issue instructions to desynchronize the Facilities or equipment of the Suspended Participant referred to in the request for disconnection, on the date and at the time specified in the request for disconnection. The System Operator shall not issue instruction to synchronize or reconnect such Facilities or equipment until it receives the notice referred to in Clause 16.2.2.10 and shall synchronize or reconnect such Facilities or equipment on the date and at the time specified in such notice.

16.2.2.9. The Transmission or Distribution Network Service Provider, as the case may be, which receives a request for disconnection from the Market Operator, shall disconnect the Facilities or equipment of the Suspended Participant referred to in the request for disconnection, on the date and at the time specified in the request for disconnection. The Transmission or Distribution Network Service Provider, as the case may be, shall not reconnect such Facilities or equipment until it receives the notice referred to in Clause 16.2.2.11, and shall reconnect such Facilities or equipment on the date and at the time specified in such notice. No costs associated with disconnection and reconnection shall be borne by the Market Operator. If the relevant Transmission or Distribution Licensee does not disconnect the Market Participant on the date and at the time specified in the request for disconnection, it shall be liable for payment of any charges that arise as a result of such delay in disconnection.

16.2.2.10. The Market Operator may at any time and upon notice to the Suspended Market Participant, extend, stay the operation of or withdraw a Suspension Order as well as the request for disconnection or modify the conditions of any Suspension Order as well as the request for disconnection, and shall inform the Authority, the Transmission or Distribution Network Service Provider, as the case may be, accordingly.

16.2.2.11. The Market Operator shall, immediately following the issuance of a Suspension Order, publish a notice on the MO Website and issue a public statement that the rights of the Suspended Market Participant to participate in the CTBCM have been Suspended or restricted, including details of the suspension or restriction, and whether a request for disconnection has also been issued in respect of the Suspended Market Participant. The Market Operator shall issue a public notice promptly after a Suspension Order and, where applicable, a request for disconnection, is withdrawn, extended, modified or stayed and publish the same on the MO Website.

16.2.2.12. With effect from the date of issuance of Suspension Order, the Suspended Market Participant shall not be eligible to trade or enter into any transaction in the CTBCM to the extent specified in the Suspension Order.

16.2.2.13. The Suspended Market Participant shall comply with the terms of the Suspension Order issued to it. A Suspended Market Participant shall also comply with any subsequent order, including any directions or arrangements which may be made for the purpose of giving effect to the Suspension Order, made by the Market Operator.

16.2.2.14. A Suspended Market Participant shall remain liable for all of its obligations as a Market Participant, other than as expressly provided in the Suspension Order, including but not limited to, the payment of any amounts to the Market Operator in respect of any Energy withdrawn while the Suspension Order is in effect. Issuance of a Suspension Order shall not affect any liability or obligation of a Suspended Market Participant for the payment of any amounts to the Market Operator or any other person which were incurred or arose under this Code:

a) prior to the date on which the Suspension Order was issued; or

b) during any period in which the operation of the Suspension Order has been stayed;

regardless the date on which any claim relating thereto may be made.

16.2.3. REVOCATION OF ENROLMENT AND TERMINATION OF MARKET PARTICIPATION AGREEMENT

16.2.3.1. The Market Operator may, by Termination Order, revoke the enrolment of a Market Participant and terminate its Market Participation Agreement as well as its right to participate in the CTBCM where a Suspended Market Participant:

a) has not remedied, to the satisfaction of the Market Operator, the Event of Default which caused the issuance of the Suspension Order within (30) Business Days of the date of issuance of the Suspension Order or any other date as specified by the Market Operator; or

b) has informed the Market Operator that it is not likely to remedy such Event of Default.

16.2.3.2. Notwithstanding that a Market Participant may have remedied breach of this Code pursuant to the non-compliance letters or other remedial actions taken against it in accordance with Sub-Section 16.3.1, the Market Operator may, by Termination Order, revoke the enrolment of a Market Participant and terminate a Market Participant's right to participate in the CTBCM if a Market Participant has been found to be in breach of this Code on a persistent basis.

16.2.3.3. Where the Market Operator intends to issue a Termination Order, the Market Operator may issue a notice of intention, including the reasons thereof, to the concerned Market Participant indicating that the following may be issued:

a) a Termination Order to revoke the enrolment of the Market Participants and the reasons thereof;

b) a request to the relevant Transmission or Distribution Network Service Provider, if not already issued, for permanent disconnection of the relevant Facilities or equipment of the Terminated Market Participant from the Transmission Network or the Distribution Network as the case may be.

16.2.3.4. The Market Operator shall provide a copy of the notice issued pursuant to Clause 16.2.3.3 to the Authority and the relevant Transmission or Distribution Network Service Provider.

16.2.3.5. Upon receipt of the notice issued pursuant to Clause 16.2.3.3, the concerned Market Participant shall have the right to request, within two (2) Business Days, a meeting with the Market Operator to justify that the Termination Order, the request for disconnection, or both, as the case may be, shall not be issued.

16.2.3.6. Where the Market Participant:

a) has not requested a meeting pursuant to Clause16.2.3.5, or has notified the Market Operator that it does not intend to request such a meeting; or

b) has requested a meeting, then upon conclusion of a meeting, the Market Operator may:

b.1. issue a Termination Order to the Market Participant revoking its enrolment or restricting all of the Market Participant's rights to participate in the CTBCM; and/or

b.2. if not already issued, issue, with a copy to the Market Participant, a request to the relevant Transmission or Distribution Network Service Provider requesting permanent disconnection of the relevant Facilities or equipment of the Terminated Market Participant from the Transmission Network or the Distribution Network as the case may be; and/or

b.3. make such other order with adequate justification for remedial of the default.

16.2.3.7. Where the Market Participant has requested a meeting pursuant to Clause16.2.3.5, the Market Operator, within ten (10) Business Days of the date of receipt of such request, shall hold a meeting providing the Market Participant with a reasonable opportunity to justify that why the Termination Order, the Disconnection Order or both should not be issued against it. In such circumstances, the Market Operator shall not issue either the Termination Order, the Disconnection Order or any other order until such meeting has been held.

16.2.3.8. Upon receipt of the disconnection request from the Market Operator, the System Operator shall issue instructions to desynchronize the Facilities or equipment of the Terminated Participant referred to in the request for disconnection, on the date and at the time specified in the request for disconnection. The System Operator shall not issue instructions to synchronize or reconnect such Facilities or equipment until Terminated Market Participant is again admitted as a Market Participant in accordance with this Code, and in case it is exempted from enrolment, it has cleared all of its obligations with the Market Operator and the Market Operator informs the System Operator accordingly. No costs associated with disconnection and reconnection shall be borne by the Market Operator.

16.2.3.9. Upon receipt of the request for disconnection, the Transmission or Distribution Network Service Provider shall, on the date and at the time specified in the request for disconnection, disconnect the relevant Facility or equipment of the Terminated Market Participant referred to in the request for disconnection. The Transmission or Distribution Network Service Provider, as the case may be, shall not reconnect such Facilities or equipment until the Terminated Market Participant is again admitted as a Market Participant in accordance with this Code, in case it is exempted from enrolment, it has cleared all its obligations with the Market Operator and the Market Operator informs the relevant Transmission or Distribution Network Service Provider accordingly. No costs associated with disconnection and reconnection shall be borne by the Market Operator. If the relevant Transmission or Distribution Licensee does not disconnect the Market Participant on the date and at the time specified in the request for disconnection, it shall be liable for payment of any charges that arise as a result of such delay in disconnection.

16.2.3.10. With effect from the date of issuance of the Termination Order, all rights of the Terminated Market Participant to participate in the CTBCM shall stand terminated.

16.2.3.11. The Market Operator shall, immediately following the issuance of a Termination Order, publish the Termination Order on the MO Website and issue a public announcement that the rights of the Terminated Market Participant to participate in the CTBCM have been terminated and that a request for disconnection has been issued in respect of the Terminated Market Participant.

16.2.3.12. A Terminated Market Participant shall remain subject to and liable for all of its obligations and liabilities as a Market Participant, which were incurred or arose under this Code due to actions of the terminated Market Participant prior to the date on which it ceases to be a Market Participant, regardless of the date on which any claim relating thereto may be made. The Market Operator may withhold the Security Cover or Settlement Guarantee Cover amount in full or a portion thereof of the Terminated Market Participant, if it considers that there are charges to be calculated in future for the upcoming yearly Settlement Statement which may be payable by the Market Participant

16.2.3.13. A Terminated Market Participant who desires to be readmitted as a Market Participant shall be required to re-apply for enrolment to participate in the CTBCM, in accordance with the provisions of Chapter 2. The Market Operator may impose such additional terms and conditions on the right of the Market Participant to participate in the CTBCM as deemed appropriate in the circumstances, whether or not such terms and conditions are otherwise applicable to other Market Participants or has been provided under this Code.

16.3. Non-compliance

16.3.1. Non-Compliance Warning Letters and other remedial Actions

16.3.1.1. This Sub-Section sets forth the manner in which the Market Operator may issue non-compliance warning letters and or take other remedial actions against the Market Participants for breaches of this Code.

16.3.1.2. Where a remedial action is provided in respect of a breach of this Code, the Market Operator shall:

a) determine the level of non-compliance by the Market Participant in accordance with Clause 16.3.1.3;

b) determine the rate of recurrence of non-compliance by the Market Participant in accordance with Clause 16.3.1.4;

c) based on the determinations made in accordance with paragraphs (a) and (b), determine whether to issue a non-compliance warning letter or to take other remedial actions; and

d) where a determination is made to take other remedial actions, it shall be taken in accordance with Clause 16.3.1.5.

16.3.1.3. The Market Operator shall determine the level of non-compliance referred to in Clause 16.3.1.2.a) above as follows:

a) Level "L1" shall be determined where the Market Participant has complied in part, but not in whole, with all the requirements of a Clause or a provision of this Code and where the Market Participant has, on its own initiative, informed the Market Operator on a timely basis of the non-compliance, the reasons for non-compliance and the manner in and the time within which such non-compliance will be remedied;

b) Level "L2" shall be determined where the Market Participant has failed to comply with all of the requirements of a Clause or a provision of this Code and where the Market Participant has, on its own initiative, informed the Market Operator on a timely basis of the non-compliance, the reasons for non-compliance and the manner in which and the time within which such non-compliance will be remedied;

c) Level "L3" shall be determined where the Market Participant has failed to comply, in whole or in part, with all of the requirements of a Clause or a provision of this Code and has failed to inform the Market Operator of the non-compliance on its own initiative and on a timely basis but, at the Market Operator's notice and within the time specified in the notice, informs the Market Operator of the reasons for non-compliance and the manner in which and the time within which such non-compliance will be remedied; and

d) Level "L4" shall be determined where the Market Participant has failed to comply, in whole or in part, with all of the requirements of a Clause or a provision of this Code and has failed to inform the Market Operator of the non-compliance on its own initiative, and on a timely basis, and has failed to respond to the Market Operator's notice, within the time specified in the notice, for a statement of the reasons for such non-compliance and of the manner in which and the time within which such non-compliance will be remedied.

16.3.1.4. The Market Operator shall determine the rate of recurrence of non-compliance as referred to in Clause 16.3.1.2.b) based on the frequency and duration of the breaches of this Code.

16.3.1.5. Subject to the provisions of Clause 16.3.1.6, based on the determinations made under Clause 16.3.1.2 and the provisions of the table set forth below, the Market Operator may issue a warning letter for non- compliance and/or take other remedial actions as specified in the following table:

Table 2: Remedial Actions

Level of Non-Compliance	Range of Sanctions
L1	Non-Compliance warning letter
L2	Non-Compliance warning letter and/or remedial action under Market Participation Agreement
L3	Non-Compliance warning letter and/or remedial action under Market Participation Agreement
L4	Non-Compliance warning letter and remedial action under Market Participation Agreement

16.3.1.6. While taking the remedial actions as provided in the table in Clause 16.3.1.5, the Market Operator, and where appropriate, the Adjudication Tribunal, shall have regard to:

a) the circumstances in which the breach occurred;

b) the severity of the breach;

c) whether the breach was inadvertent, negligent, deliberate or otherwise;

d) the length of time the breach was not remedied;

e) the actions of the Market Participant on becoming aware of the breach;

f) whether the Market Participant disclosed the matter to the Market Operator on its own or whether it was notified by the Market Operator;

g) any benefit that the Market Participant obtained or expected to obtain as a result of the breach;

h) any previous breach by the Market Participant of this Code;

i) the impact of the breach on other Market Participants;

j) the impact of the breach on the CTBCM as a whole; and/or

k) such other relevant matters as the Market Operator considers appropriate.

16.3.1.7. Where:

a) a Market Participant has breached a Clause or a provision for which no penalty is specified in the Commercial Code; or

b) a Market Participant has failed to comply with an order made pursuant to Sub-Section 16.1.2, the Market Operator may, without prejudice to any other enforcement actions that are provided in this Code, take remedial actions against the Market Participant as per Market Participation Agreement after having regard to the criteria set forth in Clause 16.3.1.6 and to the factors noted in Clause 16.3.1.8.b), where applicable.

16.3.1.8. The Market Operator may take severe remedial actions against a Market Participant otherwise provided for in Clause 16.3.1.5 where:

a) the Market Operator determines that the impact of the Market Participant's breach on the CTBCM is particularly severe; or

b) the rate of recurrence of non-compliance by the Market Participant with this Code is of such frequency or duration as to warrant severe level of remedial action.

16.3.1.9. No additional remedial actions shall be taken in respect of a breach of this Code for which a remedial action has already been taken, provided that nothing in this Clause shall prevent the Market Operator from taking remedial actions for failure by a Market Participant to remedy a breach in respect of which a remedial action has been taken against it or if there is any repetition or continuation of such breach.

16.3.2. OFFICERS AND AGENTS

16.3.2.1. If any director, officer, employee, partner or agent of a Market Participant, the Transmission Service Provider, the Distribution Network Service Provider, the System Operator or the Market Operator does any act or refrains from doing any act which if done or omitted to be done, as the case may be, by a Market Participant, the Transmission Service Provider, the Distribution Network Service Provider, the System Operator or the Market Operator would constitute a breach of this Code, such act or omission shall be deemed, for the purposes of this Chapter of the Commercial Code, to be the act or omission of the Market Participant, the Transmission Service Provider, the Distribution Network Service Provider, the System Operator or the Market Operator, as the case may be.

16.3.3. NON-COMPLIANCE BY SERVICE PROVIDERS AND SYSTEM OPERATOR

16.3.3.1. In case the Market Operator considers, on the basis of its own information or upon receipt of written information from any person, that a Service Provider or the System Operator may have breached or may be breaching any provision of this Code, including an Event of Default under Sub-Section 16.2.1, the process provided in Sub-Section 16.1.2 shall, *mutatis mutandis*, apply.

16.3.3.2. If the Service Provider or the System Operator, as the case may, does not comply with the order made pursuant to Clause 16.1.2.7, the Market Operator shall inform the Authority.

Chapter 17. DISCLOSURE, ACCESS AND CONFIDENTIALITY

17.1. MAINTENANCE OF RECORDS

17.1.1.1. The Market Operator shall make and publish, and may from time-to-time revise, a record keeping policy for Records, or classes of Records prepared by the Market Operator, the System Operator, the Service Providers and Market Participants in connection with this Code.

17.1.1.2. The Market Operator, the System Operator and each Market Participant and Service Provider shall retain Records or classes of Records prepared for or in connection with this Code for at least five (5) years or any other longer period as per Applicable Law.

17.1.1.3. Where a Record is:

a) prepared in one or more draft forms;

b) not circulated in any such draft form by the person preparing it; and

c) subsequently prepared in final form;

only the final form of the Record is required to be retained.

17.2. INFORMATION DISCLOSURE

17.2.1.1. Where a person is required by this Code to disclose or provide a Record to another person, such Record shall be disclosed or provided within the time specified in, and in the form and manner required by, the applicable provisions of this Code. Where no time is specified in relation to the disclosure or provision of a specific Record, the Record shall be disclosed or provided within a reasonable time.

17.2.1.2. A Record disclosed or provided shall be, to the best of the disclosing person's knowledge, true, correct and complete at the time at which such disclosure or provision is made. No person shall knowingly or recklessly disclose or provide a Record that, at the time and in light of the circumstances in which such disclosure or provision is made, is misleading or deceptive or does not state a fact that is required to be stated or that is necessary to make the statement not misleading or deceptive.

17.2.1.3. Where a person discovers that a Record disclosed or provided by it to any other person was, at the time at which it was disclosed or provided, or becomes untrue, incorrect, incomplete, misleading or deceptive, the disclosing or providing person shall immediately rectify the situation and disclose or provide the true, correct, complete, not misleading or not deceptive Record to the person to whom the original or currently untrue, incorrect, incomplete, misleading or deceptive Record had been disclosed or provided.

17.2.1.4. The System Operator and the Market Operator are entitled to use any Record obtained pursuant to this Code and the Grid Code in performing their functions and duties under this Code, the Grid Code, their Licences or Applicable Law.

17.3. ACCESS TO THE INFORMATION

17.3.1. ACCESS TO INFORMATION AND CONFIDENTIALITY

17.3.1.1. Subject to the Applicable Law, the Market Operator shall not disclose the Confidential Information to any person. However, upon application by an interested person, the Market Operator may disclose the Non-Confidential Information which is not available on MO Website on such terms and conditions as may be deemed appropriate.

17.3.1.2. All information, other than Confidential Information, required by this Code to be made available to Market Participants or other persons shall be either published by the Market Operator on the MO Website or may be provided in such manner and within the time prescribed by this Code. Where no time is specified in respect of the provision of a particular piece of information, such information shall be published or made available within a reasonable time.

17.3.1.3. The Market Operator shall determine and classify which information may be published on the MO Website related to the CTBCM for Market Participants, the Service Providers, other stakeholders and the public in general.

17.3.1.4. The following information and documents shall be published on the MO Website:

a) the Market Participant Admission Application form;

b) the standard Market Participation Agreement;

c) The standard Service Provider Agreement;

d) The Commercial Code;

e) The Grid Code;

f) The Commercial Code amendment proposals under consideration;

g) The Commercial Code Operational Procedures;

h) The Market Participants Register;

i) Load forecasts and load statistics of the Grid System;

j) The System Marginal Price;

k) The results of the Balancing Mechanism for Capacity; and

l) The results of the verification compliance with the Capacity Obligations; and

m) The Capacity Certificates issued for each Generator; and

n) Any other information or documents as deemed appropriate and/or directed by the Authority.

17.3.1.5. The Market Operator shall develop a secured portal where information, which is not in public domain, may be accessed by the Market Participants, Service Providers and Enrolled Persons in a secured manner. The portal may, *inter alia*, include the following:

a) the reports issued by the Market Operator or the System Operator where this Code requires that such report shall be provided to the Market Participants or Service Providers or Enrolled Persons;

b) compensations for Ancillary Services; and

c) expected and actual Transmission Must Run or Reliability Must Run and its compensation.

17.3.1.6. No Market Participant, Service Provider, the System Operator or the Market Operator:

a) shall disclose Confidential Information to any person, except as expressly permitted by this Code;

b) shall permit access to Confidential Information by any person not authorized to have such access pursuant to this Code; and

c) shall use or reproduce Confidential Information for a purpose other than the purpose for which it was disclosed, or another purpose contemplated by this Code.

17.3.1.7. The Market Operator shall establish and maintain internal controls and measures, including measures relating to the protection of Confidential Information that enable the Market Operator to monitor and comply with its obligations.

17.3.2. EXCEPTIONS

17.3.2.1. Unless prohibited by the Applicable Law, nothing in this Code shall prevent:

a) the disclosure, use or reproduction of information, if the information is, at the time of disclosure, generally and publicly available other than as a result of a breach of confidence by a Market Participant or the Market Operator;

b) the disclosure of Confidential Information by a Market Participant or the Market Operator to:

b.1. its director or employee, where such director or employee requires the Confidential Information for the due performance of that person's duties and responsibilities; or

b.2. its legal or other professional advisor, auditor or other consultant, where such legal or other professional advisor, auditor or other consultant requires the information for purposes of this Code, or for the purpose of advising the Market Participant or the Market Operator in relation thereto;

c) the disclosure, use or reproduction of Confidential Information:

c.1. by the Market Participant that provided the Confidential Information;

c.2. with the consent of the Market Participant that provided the Confidential Information; or

c.3. in the case of Settlement Data or Metering Data, by or with the consent of the Market Participant to whom such data relates;

d) the disclosure, use or reproduction of Confidential Information to the extent required by Applicable Law or by a lawful requirement of any government or governmental body, regulatory body, authority or agency having jurisdiction over a Market Participant or the Market Operator;

e) the disclosure, use or reproduction of Confidential Information if required in connection with legal proceedings, mediation, arbitration, expert determination or other dispute resolution mechanism relating to this Code, or for the purpose of advising a person in relation thereto; and

f) the disclosure of Confidential Information, if required to protect the health or safety of personnel, equipment or the environment.

17.3.3. Cost of Access and Electronic Data Receiving and Sharing

17.3.3.1. Nothing in this Code shall prevent information which is made available by means of electronic communications from being provided on a read-only basis.

17.3.3.2. Nothing in this Code shall prevent the Market Operator from issuing or receiving any information or documents through electronic means.

17.3.3.3. Each Market Participant and any other person accessing, retrieving or storing information published or otherwise made available by the Market Operator shall be responsible for its own costs of accessing, retrieving or storing such information.

Chapter 18. MISCELLANEOUS, COMPLEMENTARY AND TRANSITORY PROVISIONS

18.1. Supplementary Provisions

18.1.1. Market Participants Holding Multiple Licenses or Authorizations

18.1.1.1. Wherever a Section, Sub-Section, Clause or provision of this Code is applicable to a specific Category of Market Participants and/or it is used in any kind of calculation, it shall be interpreted as applicable to all Market Participants belonging to such Category, and the provisions shall be construed accordingly.

18.1.1.2. Where a Market Participant, in addition to any other License, is also Licensed as a Transmission or Distribution Network Service Provider, the Metering Points shall be established at:

a) The interface between a Generation Plant and/or Generation Unit, as applicable, and the Transmission or Distribution Network; and

b) Any other point within the Transmission or Distribution Network that the Market Operator or the System Operator considers necessary, for the appropriate implementation of this Code;

c) Commercial Metering System shall be installed at such locations as mentioned in Clause (a) and (b), regardless there are any commercial transactions at these points.

18.1.1.3. While processing the Application submitted by an Applicant, which also holds a Transmission or Distribution License, the Market Operator shall determine, in consultation with the System Operator, the points in the network referred to in Clause 18.1.1.2.b) at which Commercial Metering System shall be installed. The Market Operator is entitled to withhold the enrolment of such Applicant, in one or more of the Categories requested by the Applicant, until the required Commercial Metering Systems are properly installed and commissioned.

18.2. Transitory Provisions

18.2.1. Initial Metering Service Provider

18.2.1.1. Prior to the CMOD, the National Transmission and Despatch Company shall be enrolled with the Market Operator as a Metering Service Provider in order to perform the functions of a Metering Service Provider as set out in this Code as well as the Grid Code to provide metering services in whole Pakistan and other territories where the applicability of the Act is not extended except those areas served by KE. Similarly, KE shall also be enrolled with the Market Operator as a Metering Service Provider in order to perform the functions of a Metering Service Provider as set out in this Code as well as the Grid Code to provide metering services in the area specified in its Licenses. With the progress of the Market, other Metering Service Providers may also be enrolled with the Market Operator.

18.2.2. Manual Meter Reading

18.2.2.1. All Metering Points shall be equipped with hardware or software for remote reading and collection of metering data through the Secured Metering System, as prescribed in Clause 4.2.1.2.b) and the Metering Service Provider shall make all efforts to comply with this requirement prior to the CMOD.

18.2.2.2. The Metering Service Provider shall establish a schedule for Local Meter Reading from the Metering Points where communication equipment has failed to electronically transmit the metering information to the database of the Metering Service Provider.

18.2.2.3. The Metering Service Provider shall submit to the Market Operator a specific request for each Metering Point on which Local Meter Reading shall be performed, along with:

a) the schedule and time for each Meter reading; and

b) a plan to correct the deficiencies, which may include the replacement of the Meter or the Commercial Metering System, as the case may be, and to incorporate such Metering Point into the SMS system.

18.2.2.4. The Market Operator shall analyse the request and, if deemed appropriate, authorize the Metering Service Provider to perform Local Meter Reading at such Metering Point, notifying such authorization for a pre-specified period.

18.2.2.5. While performing Local Meter Reading, the Metering Service Provider shall perform an inspection of the metering facilities and if the Metering Service Provider detects any anomaly, including maintenance defects, inappropriate equipment, or evidence of tempering or suspicion thereof, it shall prepare a Metering Incident Report, informing this situation to the Market Operator.

18.2.2.6. The information collected by the Metering Service Provider for each Meter associated with a Metering Point shall be determined by the Metering Service Provider, but it shall include at least:

a) half-Hourly readings of active and, if applicable, reactive Energy, with their associated time stamps in all cases the Meter installed at the Metering Point provides for such capability;

b) accumulated readings of active and, if applicable, reactive Energy, for the previous month;

c) time and date stamps;

d) alarms and event logs produced by the Meter;

e) accuracy qualificators of the meter readings if the Meter produces such kind of information.

18.2.2.7. In case of successful reading of a Local Meter Reading, the Metering Service Provider shall analyse the completeness and reliability of the data obtained, in particular:

a) absence of alarm signals from the Meter;

b) adequacy of time and date stamps;

c) completeness of readings for the Meters and validation;

d) the contents of the event log of the Meter; and

e) the adequacy of the parameters programmed in the Meter and metering equipment.

18.2.2.8. After the analysis of the completeness and reliability of the metering data, the Metering Service Provider shall decide about the correctness of the values obtained and shall mark the obtained data as "complete and accurate", "incomplete but accurate" or "inaccurate", as the case may be.

18.2.3. Initial Capacity Obligations

18.2.3.1. With effect from the CMOD, the following values shall be applicable for the Capacity Obligations:

a) For Suppliers of Last Resort, the values provided in Table 3 below.

b) For Competitive Electric Power Suppliers, the values provided in Table 4 below.

c) For BPCs which are enrolled as Market Participants, the values provided in Table 5 below.

d) For Traders involved in Firm Exports, the values provided in Table 6 below.

Table 3: Capacity Obligations for Suppliers of Last Resort

Period		Capacity Obligations (In % of the registered or forecasted Maximum Demand at System Peak Hours)
Ex-post compliance with the Capacity Obligations	Previous year (1)	100
Ex-ante compliance with the Capacity Obligations	Current year (2)	100
	Year 1 (3)	100
	Year 2	100
	Year 3	1-CAGR
	Year 4	1-CAGR

(1) Previous year is the year immediately before the year in which compliance with the Capacity Obligations is verified. For the first year after the CMOD, the previous year's calculations shall not be applicable.

(2) Current year is the year in which compliance with the Capacity Obligations is being verified.

(3) Year 1 is the year immediately after the year in which compliance with the Capacity Obligations is verified, and Year 2, 3, and 4 shall be construed accordingly.

Table 4: Capacity Obligations for Competitive Electric Power Suppliers

Period		Capacity Obligations (In % of the registered or forecasted Maximum Demand at System Peak Hours)
Ex-post compliance with the Capacity Obligations	Previous year (1)	100
Ex-ante compliance with the Capacity Obligations	Current year (2)	100
	Year 1 (3)	100
	Year 2	100
	Year 3	1-CAGR
	Year 4	1-CAGR

(1) Previous year is the year immediately before the year in which compliance with the Capacity Obligations is verified. For the first year after the CMOD, the previous year's calculations shall not be applicable.

(2) Current year is the year in which compliance with the Capacity Obligations is being verified.

(3) Year 1 is the year immediately after the year in which compliance with the Capacity Obligations is verified, and Year 2, 3, and 4 shall be construed accordingly.

Table 5: Capacity Obligations for BPC

Period		Capacity Obligations (In % of the of the registered or forecasted Maximum Demand at System Peak Hours)
Ex-post compliance with the Capacity Obligations	Previous year (1)	100
Ex-ante compliance with the Capacity Obligations	Current year (2)	100
	Year 1 (3)	100
	Year 2	100
	Year 3	1-CAGR
	Year 4	1-CAGR

(1) Current year is the year in which compliance with the Capacity Obligations is being verified.

(2) Previous year is the year immediately before the year in which compliance with the Capacity Obligations is verified. For the first year after the CMOD, the previous year's calculations shall not be applicable.

(3) Year 1 is the year immediately after the year in which compliance with the Capacity Obligations is verified, and Year 2, 3, and 4 shall be construed accordingly.

Table 6: Capacity Obligations for Traders involved in Firm Exports

Period		Capacity Obligations (In % of the of the registered or forecasted Maximum Demand at System Peak Hours)
Ex-post compliance with the Capacity Obligations	Previous year (1)	100
Ex-ante compliance with the Capacity Obligations	Current year (2)	100
	Year 1 (3)	100
	Year 2	100
	Year 3	1-CAGR
	Year 4	1-CAGR

(1) Previous year is the year immediately before the year in which compliance with the Capacity Obligations is verified. For the first year after the CMOD, the previous year's calculations shall not be applicable.

(2) Current year is the year in which compliance with the Capacity Obligations is being verified.

(3) Year 1 is the year immediately after the year in which compliance with the Capacity Obligations is verified, and Year 2, 3, and 4 shall be construed accordingly.

18.2.4. METHODOLOGY AND FACTORS FOR ALLOCATION OF LEGACY CONTRACTS-CPPA-G

18.2.4.1. The National Electricity Policy stipulates that power allocation / distribution from the power pool to state-owned suppliers or any other entity shall continue in accordance with the existing power pool allocation mechanism, or as may subsequently be provided for in the National Electricity Plan. In order to calculate the Allocation Factors, the following procedure shall be adopted by the Market Operator:

a) for each Ex-WAPDA DISCO, except PESCO and TESCO, the capacity payments during the last three years (2020, 2021, 2022) shall be utilized to calculate the average share of each of these Ex-WAPDA DISCO in the pool;

b) for PESCO and TESCO, a combined Allocation Factor shall be established first based on their combined capacity payments during the last three years (2020, 2021, 2022) to calculate the average share of these EX-WAPDA DISCOs in the pool.

c) the individual Allocation Factor for PESCO and TESCO shall be established based on the capacity payments share between PESCO and TESCO in year 2021-22; and

d) the KE shall be assigned its share as per the terms and conditions of its PPAA or any other arrangement in place with CPPA-G (SPA).

18.2.4.2. The Market Operator shall publish the Allocation Factors for each EX-WAPDA DISCO and KE before the CMOD and shall subsequently update these factors upon revision as per provision of Sub-Section 18.2.5.

18.2.4.3. The Allocation Factors shall be used for the following three purposes:

a) Planning

b) Energy Imbalances

c) Capacity Invoices by Special Purpose Agent

18.2.4.4. The Allocation factors published by the Market Operator pursuant to Clause 18.2.4.2 shall be used for planning purposes and Energy Imbalances only. For Capacity Invoices by the Special Purpose Agent (SPA), the following transition shall be adopted for calculation of the Allocation Factors:

a) At least three (3) years of coincidental MDI data shall be used for calculation of the Allocation Factors.

b) Installation of Commercial Metering System as per provisions of the Commercial Code and Grid Code on all Metering Points especially the Metering Points between PESCO and TESCO.

18.2.4.5. Once the Allocation Factors are calculated on the coincidental MDI data, then the same Allocation Factors shall be used for all of the above three purposes as stated in Clause 18.2.4.3 above.

18.2.5. Revision of the Allocation Factors

18.2.5.1. After verification of compliance with ax-ante Capacity Obligations as per procedure set forth in Chapter 10 or ex-post Capacity Obligations as per Sub-Section 9.7.1, for EX-WAPDA DISCOs in their role as Suppliers of Last Resort, the Market Operator shall revise the Allocation Factors as follows:

a) Where any of the EX-WAPDA DISCO is found non-compliant with its Capacity Obligations in any of the year being verified, and there is surplus Capacity available with other EX-WAPDA DISCOs, the non-compliance shall be resolved by allocating the Capacity from the EX-WAPDA DISCOs who have surplus to the EX-WAPDA DISCOs who are in deficit as follows:

a.1. In case the total deficit amount is less than the total surplus amount, then the surplus amount shall be distributed on pro-rata basis and the Allocation Factors shall be revised accordingly;

a.2. In case the total deficit amount is greater than the total surplus amount, then each EX-WAPDA DISCO in deficit will get a share of the available surplus on pro-rata basis and the Allocation Factors shall be revised accordingly.

18.2.5.2. The Allocation Factors revised as per Clause 18.2.5.1 shall be published by the Market Operator as per Clause 18.2.4.2.

18.2.5.3. The Market Operator shall include the detailed calculations performed as per Clause 18.2.5.1 in the report regarding compliance with Capacity Obligations containing at least the compliance status of the EX-WAPA DISCOs before and after the revision of the Allocation Factors for different years.

18.2.5.4. In case an existing EX-WAPDA DISCO is bifurcated into new companies, the Allocation Factor shall be revised based on the allocation of Metering Points.

18.2.6. Default Interest

18.2.6.1. The Default Interest rate on any amount not paid within the due date shall be (one month KIBOR + 2 %) or any other value as determined by the Market Operator from time to time.

18.2.7. UNITARY COST OF CAPACITY

18.2.7.1. Till the time, the System Operator devises a detailed methodology for determining the Unitary Cost of Capacity, as an interim measure, the unitary cost of Capacity shall be equal to (10,500,000) PKR/MW/year.

18.2.8. EFFICIENT LEVEL OF RESERVES

18.2.8.1. Till the time, the System Operator determines the efficient level of reserves, as an interim measure, the value of efficient level of reserves shall be equal to (35%).

18.2.9. TRANSITION TOWARDS GUARANTEE BASED MECHANISM

18.2.9.1. The Market Operator shall prepare bi-annually a report on the behaviour of the Market Participants regarding payments and shall submit the same to the Authority along with recommendations regarding feasibility of moving from the cash-based system of Security Covers, Settlement Guarantee Cover and Advance Instalments towards a bank guarantee-based mechanism. First such report shall be prepared after two years of the CMOD.

18.2.10. REGISTRATION OF LEGACY CONTRACTS-CPPA-G

18.2.10.1. Before CMOD, the Market Operator shall register all Legacy Contracts-CPPA-G, in its Market Settlement System as follows:

a) create an entity with the name "Legacy Generators-CPPA-G" to represent all Legacy Generators-CPPA-G. Any payment arising on account of this entity shall be discharged by the SPA;

b) the Capacity contracted through the Legacy Contracts-CPPA-G shall be treated as follows:

b.1. for EX-WAPDA DISCOs, in their role as Suppliers of Last Resort, register Generation Following Supply Contracts in a manner that each Firm Capacity Certificate of the Legacy Generators shall be shared among the EX-WAPDA DISCOs on proportional basis as per the factors published by the Market Operator as per Clause 18.2.4.2 of the Commercial Code;

b.2. for KE, block a number of Firm Capacity Certificates against its Capacity Obligations, from the Firm Capacity Certificates allocated to the EX-WAPDA DISCOs. The number of blocked Firm Capacity Certificates shall always be equal to the quantum agreed in its Power Purchase Agency Agreement or any other arrangement with the SPA;

c) the Energy contracted through the Legacy Contracts-CPPA-G shall be treated as follows:

c.1. For each hour, the net consumption of Suppliers of Last Resort (EX-WAPDA DISCOs and KE) up to the Cap shall be a deemed Customize Contract between the entity "Legacy Generators" and the respective Supplier of Last Resort. The net consumption of:

i. EX-WAPDA DISCOs as Supplier of Last Resort shall be the total consumption of the Supplier of Last Resort minus the Energy contracted bilaterally with parties other than "Legacy Generators";

ii. KE as Supplier of Last Resort shall be the energy withdrawn by KE on the specified Trading Points as per its PPAA or any other arrangement in place with SPA;

c.2. for KE, the Cap in each hour is the maximum quantum of Energy agreed between the CPPA-G (SPA) and KE in the PPAA or any other arrangement in place;

c.3. for each EX-WAPDA DISCOs, the Cap in each hour shall be determined as the total available Energy of the Legacy Generators in that hour minus the Energy contracted with KE in that hour and multiplying it by the Allocation Factor of the respective EX-WAPDA DISCO published by the Market Operator as per Clause of this Code;

c.4. as the Energy of the Legacy Generators varies with time, therefore the quantum available for each EX-WAPDA DISCO shall also vary. The energy available from the Legacy Generators and its quantum available for each EX-WAPDA DISCO shall be determined on hourly basis. The total available Energy of the Legacy Generators to be allocated to each EX-WAPDA DISCO shall be determined as follows:

$$AE_h\ (MWh) = AEG(vre) + AEG\left(Hydro_{run\ of\ river}\right) + \mathrm{AEG(test\ run)} + \mathrm{AEG(others)} + AC\left(hydro_{storage}\right) + AC(thermal) - EU_{KE}$$

Where:

AE_h is the available Energy of the Legacy Generators in the hour "h" to be allocated among the EX-WAPDA DISCOs;

$AEG_{(vre)}$ is Actual Energy injected in the Grid by the Generation Plants based on VRE technology (wind + solar etc.) in the hour "h" calculated pursuant to Clause 5.2.2.1 above;

$AEG_{(hydro\_run\ of\ river)}$ is the Actual Energy injected into the Grid by the Generation Plants based on the hydro run of river technology in the hour "h", calculated pursuant to Clause 5.2.2.1above;

AEG(test run) is the Actual Energy injected into the Grid by the Generation Plants, which are running on test run basis, in hour "h", calculated pursuant to Clause 5.2.2.1above;

AEG(others) means the actual Energy of all those Thermal Generation Plants whose Capacity is not being paid through the Legacy Contracts-CPPA-G, but rather payments are made on Energy basis, calculated pursuant to Clause 5.2.2.1 above;

AC(hydro_storage) is the Available Capacity of all hydro reservoir based power plants in the hour "h" as reported by the System Operator. The System Operator shall provide this information on daily basis to the Market Operator and confirm it within two (2) Business Days at the end of each month;

AC(thermal) is the Actual Available Capacity of all Thermal Generation Plants as reported by the System Operator. For the avoidance of doubt, a Generation Unit on scheduled maintenance shall also be considered as available for this calculation. The System Operator shall provide this information on daily basis to the Market Operator and confirm it within two (2) Business Days at the end of each month;

EU_{KE} is the contracted Energy between the Legacy Generators and KE in hour "h";

c.5. the Cap of the contracted Energy between Legacy Generators and each EX-WAPDA DISCO shall be determined as:

$$CAP\_DISCO_{i,h}\ (MWh) = AE_h * AF_i$$

Where:

CAP_DISCO $_{i,h}$ is the Cap on the contracted Energy between "Legacy Generators" and the EX-WAPDA DISCO "I" in hour "h";

AE_H is the available Energy of the Legacy Generators in the hour "h" to be allocated among the EX-WAPDA DISCOs, calculated pursuant to Clause 18.2.10.1.c.4 above;

AFi is the Allocation Factor of EX-WAPDA DISCO "i" published by the Market Operator as per Clause 18.2.4.2 of this Code.

Chapter 19. APPENDICES

19.1. APPENDIX I. METHODOLOGY FOR DETERMINATION OF SYSTEM MARGINAL PRICES AND ANCILLARY SERVICE CHARGES

19.1.1. GENERAL APPROACH

19.1.1.1. The Grid Code requires that the System Operator shall operate the system at its minimum cost while complying with the security and reliability criteria as set out therein. This, in turn, requires also to schedule the necessary Ancillary Services in the most economical way. The way to comply with all these provisions is to implement a Security Constrained Economic Dispatch to schedule the Energy production of each Generation Unit.

19.1.1.2. To implement the SCED, the System Operator requires necessary software tools and IT systems, as well as properly trained staff and appropriate operational procedures to ensure that the system achieves its optimal economic performance while maintaining always the required levels of reliability and security of supply.

19.1.1.3. Regardless of the fact that the System Operator may not yet be equipped with state-of-the-art software and IT systems, or that some of the operational procedures require adaptations or development of new ones, it is the duty of the System Operator that it shall make best efforts to operate the Grid System in the most economical way, within the security and reliability criteria established in the Grid Code.

19.1.1.4. Provided that the System Operator complies with the provisions of Clause 19.1.1.3, it is assumed that the results of the operations of the System Operator are aligned with the Security Constrained Economic Dispatch and, therefore, the determination of System Marginal Prices, as well as the identification of the Generation Units entitled for receiving compensation for providing, or allowing other Generation Units to provide Ancillary Services, shall be carried out through an ex-post analysis of the results of the daily operations.

19.1.2. PROCEDURE FOR DETERMINING THE SYSTEM MARGINAL PRICES

19.1.2.1. Every Business Day, the System Operator shall utilize the results of the actual operations of the previous day, or previous days in cases of non-Business Days, to develop an ordered table, in ascending order of their Variable Generation Cost or the Contract price in case of Imports, of all Generation Units and Imports for which the System Operator is responsible for Dispatching, for each hour of the day (the Variable Generation Cost List).

19.1.2.2. Each Generation Unit or Import shall have associated four values:

a) Variable Generation Cost: It is the value which was used by the System Operator for Dispatching the Generation Units and Imports in the most economical way, pursuant to Clause 19.1.1.3. In case, the Variable Generation Cost of a Generation Unit is a function of its output or Generation Unit configuration, the value to be included in the table is the value corresponding to the output or configuration at which this unit was dispatched.

b) An operational label: which shall have one of the following values:

b.1. "Unavailable", applicable to Generation Units or Imports which were not available for being Dispatched at the corresponding hour;

b.2. "Zero Fuel Cost", applicable to available Generation Units which use natural resources as primary energy which do not have an associated cost. Hydro, Solar (either PV or CSP), Wind, and other similar renewable technologies will be labelled as such. Further, Captive Power Plants and Generation Units based on cogeneration technology shall also be labelled as "Zero Fuel Cost" in case they declare their variable cost equal to zero as per provisions of the Grid Code. Nuclear Generation Units shall also be labelled as "Zero Fuel Cost" regardless its Fuel Cost may be different than zero;

b.3. "Must Purchase" applicable to available Generation Units having Legacy Contracts-CPPA-G or Legacy Contracts-KE which have to be dispatched to fulfil the contractual obligations irrespective of their variable cost;

b.4. "Transmission Must Run", applicable to available Generation Units not labelled as "Zero Fuel Cost", or "Must Purchase" which have been dispatched to alleviate Congestion due to overloading of the network equipment pursuant to Clause 6.2.3.1 above;

b.5. "Reliability Must Run", applicable to available Generation Units not labelled as "Zero Fuel Cost", or "Must Purchase" which have been dispatched to fulfil the reliability and security criteria provided in the Grid Code pursuant to Clause 6.2.3.1;

b.6. "Voltage Support" applicable to available Generation Units not labelled as "Zero Fuel Cost", or "Must Purchase" which have been dispatched by the System Operator due to unstable voltage levels in the Transmission Network pursuant to Clause 6.3.1.3 above;

b.7. "Must Stop", applicable to available Generation Units, which have not been dispatched, or have been dispatched below its maximum Capacity, to alleviate Congestion pursuant to Sub-Section 6.2.1;

b.8. "Fuel Deficiency Constraint" applicable to available Generation Units having Legacy Contracts-CPPA-G, which have not been dispatched, or have been dispatched below its maximum Capacity, to manage the fuel stock of such Generation Units;

b.9. "Test Run" applicable to available Generation Units which have produced Energy for test purposes irrespective of its declared availability or variable cost as per provisions of the Grid Code;

b.10. "Operational Constraints", applicable to available Generation Units not labelled as "Zero Fuel Cost" or "Must Purchase" or "Transmission Must Run" or Reliability Must Run" or "Voltage Support" or "Must Stop" or "Fuel Deficiency Constraint" or "Test Run", which have not been dispatched, or have been dispatched irrespective of its variable cost for other operational reasons. The System Operator shall clearly identify and document such reasons;

b.11. "Ramping", applicable to dispatched Generation Units not labelled as "Zero Fuel Cost" or "Must Purchase" or "Transmission Must Run" or Reliability Must Run" or "Voltage Support" or "Must Stop" or "Fuel Deficiency Constraint" or "Test Run" or "Operational Constraint", which are ramping up or ramping down following a sync or de-synch instruction by the System Operator under its registered technical parameters as per provisions of the Grid Code;

b.12. "Fully Loaded", applicable to available Generation Units not labelled as "Zero Fuel Cost" or "Transmission Must Run" or "Reliability Must Run" or "Must Purchase" or "Voltage Support" or "Fuel Deficiency Constraint" or "Test Run", which have been dispatched at or above ninety five percent (95%) of its maximum available Capacity. In case the available Capacity is dependent on ambient conditions, the System Operator shall consider the actual available Capacity as per the ambient conditions for this calculation;

b.13. "Partially Loaded", applicable to available Generation Units not labelled as "Zero Fuel Cost" or "Must Purchase or "Transmission Must Run" or "Reliability Must Run" or "Voltage Support" or "Must Stop" or "Fuel Deficiency Constraint" or "Test Run" or "Operational Constraint" or "Ramping", which have been dispatched below ninety five percent (95%) of its maximum available Capacity. In case the available Capacity is dependent on ambient conditions, the System Operator shall consider the actual available Capacity as per the ambient conditions for this calculation;

b.14. "Out of Merit", applicable to the available Generation Units that have not been scheduled for Dispatch by the System Operator. For the avoidance of doubt, a Generation Unit or Import may be labelled as "Out of Merit" even if this Generation Unit or Import has produced electric power during the corresponding hour, if this production has not been instructed by the System Operator.

c) The Energy injected into the Grid during the relevant hour;

d) The available Capacity: which shall be equal to:

d.1. The Energy produced during the relevant hour in case of Generation Units labelled as "Zero Fuel Cost";

d.2. The declared Available Capacity for the relevant hour as per the provisions of the Grid Code for all other cases;

19.1.2.3. An example of the table to be prepared by the System Operator is shown in Figure 2. The values included in this figure are for illustration purposes only (not representing a real situation).

Figure 2: Example of Variable Generation Cost List

#.	Generation Unit/Plant Name	Unit	Variable Generation Cost	Available Capacity	Energy Injected into the Grid	Operational Label	Remarks
1	Tarbela	Unit 1	0	175.0	175.0	Zero Fuel Cost	
2	Mangla	Unit 1	0	100.0	100.0	Zero Fuel Cost	
3	Ghazi Barotha	Unit 1	0	290.0	290.0	Zero Fuel Cost	
4	Act Wind	COMPLEX	0	30.0	30.0	Zero Fuel Cost	
5	Foundation Power Company Daharki Ltd.	COMPLEX	1.5532	178.7	180.4	Fully Loaded	
6	Halmore Power Generation Company Limited	Unit-1	2.1143	67.0	3.5	Unavailable	
7	Port Qasim Electric Power Company (Pvt.) Limited	Unit-2	3.9921	621.5	294.9	Fuel Deficiency Constraint	
8	Thar Energy	COMPLEX	4.3331	300.3	302.6	Fully Loaded	
9	Engro Powergen Qadirpur Limited	Unit-1	7.881547	120.4	99.7	Must Stop	
10	Uch-II Power (Pvt.) Limited	Unit-2	10.697964	127.4	117.0	Partially Loaded	
11	Uch-II Power (Pvt.) Limited	Unit-1	10.701329	127.4	116.7	Partially Loaded	
12	TPS Guddu (Genco-2)	Unit-12	11.03795	0.0	0.0	Unavailable	
13	TPS Guddu (Genco-2)	Unit-9	12.2564	95.0	100.0	Fully Loaded	
14	Lucky Coal	COMPLEX	15.6693	606.8	545.9	Partially Loaded	
15	Balloki Power Plant (NPPMCL)	Unit-1	22.249784	406.5	274.7	Must Purchase	
16	Quaid-e-Azam Thermal Power (Pvt) Limited	Unit-1	22.689714	395.6	275.1	Partially Loaded	
17	CCPP Nandipur (Genco-3)	Unit-1	24.0073	107.2	66.0	Reliability Must Run	
18	Orient Power Company (Private) Limited	Unit-1	24.05183	68.0	33.6	Voltage Support	

19	Saif Power Limited	Unit-1	24.462458	70.0	34.7	Transmission Must Run	
20	Rousch Pak Power Ltd.	Unit-3	25.9674	128.3	15.3	Operational Constraint	Start-up limits
21	China Power Hub Gen Company	Unit-1	33.3626	624.6	281.3	Test Run	
22	Nishat Chunian Power Limited	COMPLEX	34.91	175.9	0.0	Out of Merit	
23	Saba Power Company (Pvt.) Ltd.	COMPLEX	35.82242	111.0	0.0	Out of Merit	
24	Pak Gen Power Limited	COMPLEX	40.30997	350.0	0.0	Out of Merit	

19.1.2.4. For determining the System Marginal Price, only Generation Units labelled as "Fully Loaded" or "Partially Loaded" will be considered.

19.1.2.5. The System Marginal Price, for each hour, will be calculated as the Variable Generation Cost of the cheapest Generation Unit labelled as "Partially Loaded", which has been dispatched at a price higher than the most expensive Generation Unit labelled as "Fully Loaded".

19.1.2.6. In case that the most expensive Generation Unit dispatched is labelled as "Fully Loaded" and there are no Generation Units labelled as "Partially Loaded" dispatched at a higher price, the System Marginal Price will be the Variable Generation Cost of the last most expensive Generation Unit dispatched labelled as "Fully Loaded" Generation in the Table mentioned in Clause 19.1.2.1.

19.1.2.7. An example of discovering the System Marginal Price is shown in Figure 3. In this case, the Generation Unit "Lucky Coal", which has 606.8 MW of Available Capacity and it was Dispatched at 545.9 MW sets the System Marginal Price, which results equal to 15.66 PKR/kWh.

Figure 3: System Marginal Price based on the Variable Generation Cost List

#.	Generation Unit/Plant Name	Unit	Variable Generation Cost	Available Capacity	Energy Injected into the Grid	Operational Label	Remarks
1	Tarbela	Unit 1	0	175.0	175.0	Zero Fuel Cost	
2	Mangla	Unit 1	0	100.0	100.0	Zero Fuel Cost	
3	Ghazi Barotha	Unit 1	0	290.0	290.0	Zero Fuel Cost	
4	Act Wind	COMPLEX	0	30.0	30.0	Zero Fuel Cost	
5	Foundation Power Company Daharki Ltd.	COMPLEX	1.5532	178.7	180.4	Fully Loaded	
6	Halmore Power Generation Company Limited	Unit-1	2.1143	67.0	3.5	Unavailable	
7	Port Qasim Electric Power Company (Pvt.) Limited	Unit-2	3.9921	621.5	294.9	Fuel Deficiency Constraint	
8	Thar Energy	COMPLEX	4.3331	300.3	302.6	Fully Loaded	
9	Engro Powergen Qadirpur Limited	Unit-1	7.881547	120.4	99.7	Must Stop	
10	Uch-II Power (Pvt.) Limited	Unit-2	10.697964	127.4	117.0	Partially Loaded	
11	Uch-II Power (Pvt.) Limited	Unit-1	10.701329	127.4	116.7	Partially Loaded	
12	TPS Guddu (Genco-2)	Unit-12	11.03795	0.0	0.0	Unavailable	
13	TPS Guddu (Genco-2)	Unit-9	12.2564	95.0	100.0	Fully Loaded	
[redacted]							
15	Balloki Power Plant (NPPMCL)	Unit-1	22.249784	406.5	274.7	Must Purchase	
16	Quaid-e-Azam Thermal Power (Pvt) Limited	Unit-1	22.689714	395.6	275.1	Partially Loaded	
17	CCPP Nandipur (Genco-3)	Unit-1	24.0073	107.2	66.0	Reliability Must Run	
18	Orient Power Company (Private) Limited	Unit-1	24.05183	68.0	33.6	Voltage Support	
19	Saif Power Limited	Unit-1	24.462458	70.0	34.7	Transmission Must Run	
20	Rousch Pak Power Ltd.	Unit-3	25.9674	128.3	15.3	Operational	Start-up limits

						Constraint	
21	China Power Hub Gen Company	Unit-1	33.3626	624.6	281.3	Test Run	
22	Nishat Chunian Power Limited	COMPLEX	34.91	175.9	0.0	Out of Merit	
23	Saba Power Company (Pvt.) Ltd.	COMPLEX	35.82242	111.0	0.0	Out of Merit	
24	Pak Gen Power Limited	COMPLEX	40.30997	350.0	0.0	Out of Merit	

19.1.3. INTERIM PROCEDURE FOR DETERMINING THE GENERATORS ENTITLED TO RECEIVE COMPENSATION FOR ANCILLARY SERVICES BY THE SYSTEM OPERATOR

19.1.3.1. As provided under Clause 19.1.1.4 above, the results of the actual operations carried out by the System Operator are assumed to be aligned with those of the Security Constrained Economic Dispatch, therefore, for determination of compensation for Ancillary Services, it shall be assumed that:

a) for the available Generation Units, which have Variable Generation Costs lower than the System Marginal Price and have not been dispatched at full load other than Generation Units labelled as "Must Purchase" or "Transmission Must Run" or "Reliability Must Run" or "Voltage Support" or "Must Stop" or "Fuel Deficiency Constraint" or "Test Run' or "Ramping", it shall be considered that they have been instructed to disconnect or to reduce their output for providing Ancillary Services or to allow other Generation Units to provide the same. The System Operator shall also assign a label to such Generation Units as per Clause 6.3.1.2 to identify the type of service provided by such Generation Units for which compensation may be paid and communicate the same to the Market Operator;

b) for the available Generation Units, which have Variable Generation Costs higher than the System Marginal Price and have been partially dispatched other than Generation Units labelled as "Must Purchase" or "Transmission Must Run" or "Reliability Must Run" "Must Stop" or "Fuel Deficiency Constraint" or "Test Run" it shall be considered that they have been scheduled for providing Ancillary Services or allowing other Generation Units to provide Ancillary Services. The System Operator shall also assign a label to Such Generation Units as per Clause 6.3.1.2 to identify the type of service provided by such Generation Units for which compensation may be paid and communicate the same to the Market Operator.

19.1.3.2. As provided above, the following Generation Units shall be eligible to receive compensation for the provision of Ancillary Services:

a) Generation Units, labelled as "Zero Fuel Cost", whose Generation has been curtailed by the System Operator to allow other Generation Units to provide Ancillary Services: Such Generation Units shall receive compensation on account of Reduced Generation Compensation, which shall be calculated as per Clause 6.4.2.2;

b) Generation Units, labelled as "Operational Constraints", whose Variable Generation Cost is lower than the System Marginal Price: Such Generation Units shall receive compensation on account of Reduced Generation Compensation, which shall be calculated as per Clause 6.4.2.2;

c) Generation Units, labelled as "Partially Loaded", whose Variable Generation Cost is lower than the System Marginal Price: Such Generation Units shall receive compensation on account of Reduced Generation Compensation, which shall be calculated as per Clause 6.4.2.2;

d) Generation Units, labelled as "Voltage Support", whose Variable Generation Cost is higher than the System Marginal Price: Such Generation Units shall receive compensation for their variable cost which shall be calculated as per Clause 6.4.3.2;

e) Generation Units, labelled as "Operational Constraint", whose Variable Generation Cost is higher than the System Marginal Price: Such Generation Units shall receive compensation for their variable cost which shall be calculated as per Clause 6.4.3.2;

f) Generation Units, labelled as "Ramping", whose Variable Generation Cost is higher than the System Marginal Price: Such Generation Units shall receive compensation for their variable cost which shall be calculated as per Clause 6.4.3.2; and

g) Generation Units, labelled as "Partially Loaded", whose Variable Generation Cost is higher than the System Marginal Price: Such Generation Units shall receive compensation for their variable cost which shall be calculated as per Clause 6.4.3.2.

19.1.3.3. An illustration of the determination of the Generation Units eligible to receive compensations for the provision of Ancillary Services are shown in Figure 4. In this case, 2 Generation Units are eligible to receive compensation on account of Reduced Generation Compensation (Uch-II Power (Pvt.) Limited Unit 1 & 2)); and five Generation Units are eligible to receive variable cost compensation (Quaid-e-Azam Thermal Power (Pvt) Limited, CCPP Nandipur (Genco-3), Orient Power Company (Private) Limited, Saif Power Limited, and Rousch Pak Power Ltd.).

Figure 4: Generation Units Eligible to Receive Compensations for ASC

#.	Generation Unit/Plant Name	Unit	Variable Generation Cost	Available Capacity	Energy Injected Intot the Grid	Operational Label	Remarks
1	Tarbela	Unit 1	0	175.0	175.0	Zero Fuel Cost	
2	Mangla	Unit 1	0	100.0	100.0	Zero Fuel Cost	
3	Ghazi Barotha	Unit 1	0	290.0	290.0	Zero Fuel Cost	
4	Act Wind	COMPLEX	0	30.0	30.0	Zero Fuel Cost	
5	Foundation Power Company Daharki Ltd.	COMPLEX	1.5532	178.7	180.4	Fully Loaded	
6	Halmore Power Generation Company Limited	Unit-1	2.1143	67.0	3.5	Unavailable	
7	Port Qasim Electric Power Company (Pvt.) Limited	Unit-2	3.9921	621.5	294.9	Fuel Deficiency Constraint	
8	Thar Energy	COMPLEX	4.3331	300.3	302.6	Fully Loaded	
9	Engro Powergen Qadirpur Limited	Unit-1	7.881547	120.4	99.7	Must Stop	
10	Uch-II Power (Pvt.) Limited	Unit-2	10.697964	127.4	117.0	Partially Loaded	
11	Uch-II Power (Pvt.) Limited	Unit-1	10.701329	127.4	116.7	Partially Loaded	
12	TPS Guddu (Genco-2)	Unit-12	11.03795	0.0	0.0	Unavailable	
13	TPS Guddu (Genco-2)	Unit-9	12.2564	95.0	100.0	Fully Loaded	
14	Lucky Coal	COMPLEX	15.6693	606.8	545.9	Partially Loaded	
15	Balloki Power Plant (NPPMCL)	Unit-1	22.249784	406.5	274.7	Must Purchase	
16	Quaid-e-Azam Thermal Power (Pvt) Limited	Unit-1	22.689714	395.6	275.1	Partially Loaded	
17	CCPP Nandipur (Genco-3)	Unit-1	24.0073	107.2	66.0	Reliability Must Run	
18	Orient Power Company (Private) Limited	Unit-1	24.05183	68.0	33.6	Voltage Support	
19	Saif Power Limited	Unit-1	24.462458	200.0	34.7	Transmission Must Run	
20	Rousch Pak Power Ltd.	Unit-3	25.9674	128.3	15.3	Operational Constraint	Start-up limits
21	China Power Hub Gen Company	Unit-1	33.3626	624.6	281.3	Test Run	
22	Nishat Chunian Power Limited	COMPLEX	34.91	175.9	0.0	Out of Merit	
23	Saba Power Company (Pvt.) Ltd.	COMPLEX	35.82242	111.0	0.0	Out of Merit	
24	Pak Gen Power Limited	COMPLEX	40.30997	350.0	0.0	Out of Merit	

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Minutes of Meeting of Consultative Session on CTBCM Final Test Run Report

Title/Agenda: Stakeholders Consultation on CTBCM Final Test Run Report

Date/Venue: May 22, 2023 / Training Hall CPPA-G

Participants: Representatives from all DISCOs, NTDC (SO and TNO) and K-Electric attended the session. The list of meeting participants is placed at **Annex-1**.

Background & Agenda

- In compliance with the Authority's directives issued vide its determination NEPRA/R/DG/LIC/LAM-01/8389 dated May 31, 2022, CPPA had been tasked to undertake a Test Run of CTBCM. CPPA had also been directed by NEPRA to prepare and submit the Final Test Run Report in consultation with relevant stakeholders.

- Accordingly, CPPA prepared the final test run report and circulated the same amongst stakeholders for review and feedback. CPPA was further directed by the Market Implementation and Support Committee (MISC) of CPPA-G Board to a organize one day consultative session with the relevant stakeholders to discuss the key findings as presented in the test run report and to seek comments from the stakeholders on the same.

- For this purpose, a consultative session was organized on 22nd May 2023 at CPPA to discuss the key findings of the Test Run as reported in the Final Test Run Report.

Introduction

- The session was started the session with a briefing on the key highlights and the latest status updates pertaining to the CTBCM, including Test Run. The format of discussion was discussed with participants. It was agreed that the six important findings as mentioned in executive summary will be discussed at-length for seeking inputs/ comments, followed by rest of the report and finally all entities will be given chance in alphabetical order to provide any feedback or comments on any part of the final report. The participants agreed with the format of consultative session and then accordingly the session was carried out.

- As per the agreed format, at start, the Final Report's Table of Contents (TOCs) was presented, followed by a brief overview about contents presented in each chapter/section of the report.

- Then the session proceeded forward with detailed consultation on Executive Summary of the report. It was highlighted that the Executive Summary entails most important finding of test run and therefore, as agreed with participants, the six important findings as mentioned in the summary were discussed at length one by one. After (a) detailed explanation of the findings, (b) discussions and feedback and (c) conclusions, the next finding was discussed following the same process.

- During the course of the session, at the end of discussion on every key finding of the report as given in the Executive Summary and after reaching on a conclusion with the stakeholder, in order to ensure that no-one disagrees with the conclusion made, participants were invited to disagree with the conclusion and after ensuring that every participant is agreed on the conclusion, the point was recorded in the minutes as final conclusion/recommendation.

- The Minutes are made in two parts: Part-I covers the minutes from discussion on the key findings of the Test Run as reported in the Executive Summary and Part-II covers the other discussion done on the entire Report.

PART-I: Discussion on the Key Finding of Test Run

1. Market Governance

A. Explanation:

- Head MOD explained that the market governance ensures that all transactions in the market are conducted in a fair and transparent manner. He added that according to the CTBCM design and the Market Commercial Code, there are two types of transactions that can occur in the market:

    i. Transactions where buyers and sellers have fully contracted their energy, but imbalances may arise due to centralized economic dispatch.

    ii. Transactions where a Market Participant has installed more generation capacity than their bilateral contracts and is selling the surplus energy at the System Marginal Price.

- It was further explained that in the first type of transaction, imbalances are a natural outcome of dispatch decisions based on Economic Merit Order (EMO). Market Participants can make profits above the variable generation cost, while optimizing the System Marginal Price.

- Furthermore, in the second type of transaction, short-term extraordinary profits may occur if the generator's variable generation cost is significantly lower than the System Marginal Price. However, these profits are not an intended result of the market design or centralized economic dispatch but may arise due to nature of trading happening the market among the market participants. This may not qualify as arms-length transaction and may be subject to further scrutiny by the relevant forums.

- Therefore, it is important to bring to the notice of the Authority about such potential market transactions upfront so that Authority may conduct a thorough analysis to ensure effective market governance and decides accordingly.

B. Discussion:

- The discussion started off by the participants with queries regarding operations and financial transactions of merchant plants. The integration of merchant plants under CTBCM was explained at length with aid of examples and explanations. It was discussed at length that (a) the merchant plants will only get dispatched when their variable cost is lower than the marginal price, and (b) there is no take-or-pay capacity payments made to such plants. It was deliberated and understood that the merchant plant integration is beneficial for the system as it will not increase the cost for the consumers of DISCOs rather it will contribute to decrease it.

- Furthermore, on the query of a participant, it was clarified that only those generators who will qualify to the criteria of Merchant Plant as specified in the Commercial Code will be allowed to participate in the market as Merchant Plant.

- It was discussed that as per the current market design, although the pool is cost-based (not price-based) and the System Operator can verify or flag any anomalies in the costs reported by the generators for dispatch to NEPRA for remedy, which restricts any manipulation in the costs provided for dispatch. All participants agreed with the recommendation that it is pivotal to have Market Governance and Monitoring Unit at NEPRA.

- On enquiry of a participant, the role of Market Governance & Monitoring Unit of NEPRA was discussed. It was apprised that a Market Governance and Monitoring Unit is being established at NEPRA with the help of NREL and international consultants. The general role of such unit was elaborated, and it was apprised that apart from daily monitoring and vigilance based on market data from tools such as SDXP, SMS and MMS, the unit also furnishes annual market assessment reports.

C. Conclusion:

- It was agreed by the forum that having Merchant Plants or surplus generation without any contract in the market will be beneficial for reducing the overall system cost that will translate to overall benefits for the consumers.

- The participants appreciated the importance of the fact that NEPRA is institutionalizing a Market Governance and Monitoring Unit for effective market monitoring.

2. Balancing Mechanism for Energy

- It was explained that the Final Test Run Report notes that during the trial run, the Balancing Mechanism for Energy (BME) was executed successfully, and the Market Operator has been issuing the Settlement Statements since June 2022, however, there are few observations in the following areas:

  i) Data provision by the Metering Service Provider
  ii) Distribution Losses
  iii) Auxiliary Consumption
  iv) Marginal Price

i) Data provision by the Metering Service Provider

A. <u>Explanation:</u>

- It was explained that NTDC as Metering Service Provider (MSP) provides the hourly SMS data for the whole month, in a manner that it undertakes an exercise at month-end where it matches the manually collected monthly data from CDP meters through the field committees with SMS data to ensure that both data sets are consistent with each other. It was further highlighted that 43 no. of meters between PESCO and TESCO CDPs are still not part of SMS and because of this PESCO and TESCO settlement cannot be carried out individually.

- The report also notes that all metering points shall have Secured Metering System (SMS) on primary/main as well as backup meters for effective operations and meeting the intended purposes as per Market Commercial Code, for effective commercial market operations.

- Additionally, it was highlighted that apart from the backup meters, there should be a sufficient inventory of meters always maintained to cover meter failures.

B. <u>Discussion:</u>

- Regarding the 43 meters as mentioned in the final report, it was clarified that these are rather 44 meters to be installed at the CDPs between PESCO and TESCO. NTDC team apprised the forum that in September last year, these CDPs were identified by the MSP in coordination with PESCO, TESCO and CPPA-G. It was initially planned to roll out the installation of meters by March 2023. However, due to various reasons the meters were not installed. As an interim measure, placeholder devices have been deployed and manual data substitution is being done as per the SOP in the MSP databases.

- TESCO team apprised the forum that the original requirement was 73 which has been reduced to 44 meters. Moreover, among these 44, the 37 metering points have been cleared for installation of meters and remaining 7 are required to be finalized with PESCO. It was decided to expedite the same by mid of June 2023. Furthermore, PESCO and TESCO requested MSP to purchase the meters on their behalf. MSP team confirmed that RFP for 779 meters is being prepared including the meters for PESCO and TESCO.

- MSP NTDC representative requested that the provision of timeline of MSP data may be revised to 3 working dates after the close of the months (M+3) rather than 2 working days (M+2) as specified in the Commercial Code, this will allow the MSP to easily consolidate and validate the data. After a detailed deliberation, the forum agreed with the proposed change.

- The participants, to understand that how backup meters can affect the commercial operations of the market, raised queries regarding unavailability of back-meters at various CDPs especially between inter-DISCO CDPs. In this regard, MSP NTDC representative apprised the participants that from last 12 years, only 7 ISKRA meters have been damaged. Therefore, the probability of meter failure is significantly low. MSP team, while highlighting the resilience and reliability of ISKRA meters also apprised the forum that during the test run, only 4 meters were damaged because of reasons other than meter failures such as floods and short circuiting. The participants were also apprised that NTDC has a well-functioning metering department equipped with trained staff, tools, equipment and SOPs that has enabled provision of verified monthly metering data for almost a year.

- Even in the absence of backup meters, at certain CDPs, there is an option of taking reading from verification meter at the far end. Also, a third option also exists i.e. using SO dispatch data to consolidate the metering data in case of failure of the main and backup meters.

- MSP team demonstrated and exhibited their complete confidence in the current metering infrastructure being robust enough for enabling commercial market operations.

C. Conclusion:

- MSP to expedite the process of procurement of meters at the earliest.

- It was agreed that the timeline of MSP data provision may be revised to M+3 instead of M+2 in the Commercial Code.

- It was demonstrated by MSP NTDC that metering in its current form is robust and reliable. Backup meters should be installed but de-linked from CMOD as current metering system is adequate enough for commercial transactions. However, the complete installation of AMR meters and backup meters to be ensured and expedited by MSP.

- It was concluded that PESCO and TESCO will be settled in a combined manner until the installation of meters at the boundaries of TESCO and PESCO as currently being done under the test run. PESCO and TESCO to work closely with MSP in order to expedite the procurement and installation of meters.

ii) Distribution Losses

A. Explanation:

- The treatment of inter-DISCO losses at CDPs as per the provisions of the Commercial Code was discussed. It was apprised that Commercial Code specifies a mechanism to apply the distribution loss on inter-DISCO CDPs through uplift. However, as per the existing practice duly approved by the Authority, the inter-DISCO settlement is done on actual metered data without uplifting for losses of the DISCO from which the power is drawn. To ensure fair allocation of losses, it is imperative that the benchmarks of losses be revised for DISCOs and the same has also been recommended to the Authority in the test run report.

- In reference to this, the CPPA team requested all DISCOs to verify the exact location of their CDPs as well as the application of the relevant losses as communicated to them by the Market Operator. It was also apprised that only GEPCO has provided the requisite data whereas the same is awaited from remaining DISCOs.

B. Discussion:

- GEPCO representative highlighted the provision of Grid Code regarding transmission losses to be borne by the owner and operator of the respective transmission, which conflicts with the mechanism specified in the Commercial Code.

- It was clarified that the provisions of Grid Code are w.r.t to accounting of losses to the respective entity and the Commercial Code provides for the settlement of those losses in the respective consumer category. Hence, the provisions are not conflicting.

- The representatives of DISCOs highlighted that NEPRA has already furnished a determination on treatment of losses. Unless a new determination is issued by the Authority incorporating the methodology of the revised Commercial Code, the inter-DISCO losses can be treated under CTBCM in same manner as is being done today, which means that the impact of losses on the end-consumer tariff will remain the same as it is today unless it is further rationalized through a determination by the Authority. The DISCOs apprised that it requires studies and analysis to make a recommendation to NEPRA for changing the losses benchmarks. NEPRA will also require some time to approve the revised benchmarks.

- The forum also discussed that the inter-DISCO losses treatment shall be given a transition of two years during which the prevailing treatment will be followed. Meanwhile, the DISCOs will file a petition with the Authority to change the mechanism within 6 months.

- MEPCO representative added that the principle of equity must be duly considered with respect to the application of distribution losses as discussed in the consultative session held in December 2022. He also added that MEPCO is the largest DISCO with highest losses and is most effected by the current distribution of losses and emphasized that DISCOs must make the petitions before the Authority at the earliest in order to enable the losses and mechanism in the earliest possible time frame.

C. Conclusion/Recommendations:

- It was concluded that DISCOs will prepare a petition for submission before the Authority within 6-months for incorporation of the methodology for treatment of losses specified in the revised Commercial Code.

- A transition of two years maybe provided or until a new determination is issued by the Authority incorporating the methodology of the revised Commercial Code and as such the inter-DISCO losses be treated under CTBCM in same manner as is being done today.

iii) Auxiliary Consumption

A. Explanation:

- The forum was apprised about one of the findings of the final Test Run Report regarding NTDC's auxiliary consumption. It was explained that NTDC's auxiliary consumption as today is part of the losses and may be treated as sale of the relevant DISCO before the CMOD.

B. Discussion:

- NTDC representative apprised the forum that such auxiliary consumption to NTDC is exclusively for the control room of the grid-stations (and not for colonies at all). Therefore, NTDC is of the opinion that this consumption should not be considered as load of DISCOs. It was also apprised that NTDC is in direct correspondence with NEPRA requesting the Authority to continue the treatment of auxiliary consumption as being done today. The representative also apprised that auxiliary consumption of the control room of grid station is also very trivial to the tune of approximately Rs. 2.0 million per month.

C. Conclusion:

- It was decided by the forum that NTDC would provide their comments highlighting their apprehensions regarding considering this consumption as sale of DISCOs.

iv) Marginal Price

A. Explanation:

- The participants were apprised about the findings w.r.t Marginal Price discovery during the test run. It was explained that as noted in the Final Report, the mechanism for discovery of System Marginal Price as provided in the Commercial Code needs to be analyzed. This means that the discovery of System Marginal Price based on next plant of fully loaded (loaded above 95%) may be altered to the principle that the most expensive generation plant run on EMO other than the plants dispatched for other market charges including Ancillary Services.

- Moreover, the report notes that the labels shall also be updated upon finalizing the definitions for the different types of other charges to reflect the various states/reasons for which the plant is dispatched on the instruction of the System Operator.

B. Discussion:

- Representatives of NPCC stated that the marginal price discovery procedure has been in discussion for a long time and the first concept paper was prepared and discussed in 2019-20 between CPPA, NPCC and NEPRA. After consultation with all relevant stakeholders for couple of years, the methodology was finalized and also approved by the Regulator in the Market Commercial Code in 2022. After its approval by the Regulator following a series of consultative sessions and its agreement thereon, NPCC has implemented the Commercial Code approved Marginal Price methodology is its Marginal Price Application.

- NPCC representative also apprised that during the Test Run period, based on the feedback, the labels such as transmission must-run, reliability must-run, voltage support and fuel constraints were added in the SDXP. It was clarified by the representative that NPCC and has been putting all the required labels on the generators for every hour and no further labels are required to be updated as mentioned in the Final Report.

- NPCC ascertained that they are satisfied with the process and the labels that have been developed and implemented in the approved Marginal Price procedure. In relation to 95% loading level being proposed for tagging of a plant as fully loaded, it was apprised that mainly due to the ambient site conditions impacting loading level of a plant and governor's droop response used for primary reserves, a 5% margin is prudent and rightly determines the loading of a plant as being fully or partly loaded.

- It was further clarified by the NPCC representative that the Marginal Price Application being implemented is following the principle that the most expensive generation plant run on EMO other than the plants dispatched for other market charges including Ancillary Services sets the Marginal Price and further analysis may not be required.

C. Conclusion:

- It was concluded that the approved methodology in the Commercial Code which was finalized after years of consultation is comprehensive, and the Marginal Price calculated by the NPCC's Marginal Price Application based on the approved methodology exactly follows the principle that the most expensive generation plant run on EMO other than the plants dispatched for other market charges including Ancillary Services sets the Marginal Price and further analysis may not be required.

3. Other Market Charges

A. **Explanation:**

- It was explained that that during the trial run, the calculation of compensation for Must Run Generation and Ancillary Services was performed by the Market Operator based on the data received from the System Operator, however, the Commercial Code requires that the Energy units (kwh) for compensation to be provided by the System Operator. The inputs for calculating Energy Units to be compensated were provided by SO though.

  It was also highlighted that for ancillary services procurement, NEPRA Act has given the full mandate for procurement to System Operator for ancillary services and thereby, all details related to ancillary services are to be carried out by the System Operator. Further, the mechanism for provision of this data has been improved in the revised Commercial Code which mandates the System Operator to provide this data to the Market Operator.

- Besides the aforesaid matter, it was apprised that the Final Report notes the following three observations regarding the Must Run Generation and Ancillary Services:

  i. The report notes that the System Operator was required to identify the congested areas and zones, however, the revised Commercial Code has now provided clarity by giving a timeline for identification of the areas and zones by the SO in consultation with MO within three months from the Commercial Market Operation Date (CMOD). The code also notes that the Regulator will then approve the areas and zones.

  ii. The report also notes that the Market Commercial Code introduces the mechanism for charging of Imbalances arising due to partial loading of Generators by the System Operator to the respective Market Participants. The System Operator has to make dispatch decisions on the basis of EMO as per provisions stipulated in the Grid Code including the instruction for provision of ancillary services such as frequency regulation or voltage support. In case the partial loading of the Generation Plant is because of an action System Operator which is beyond EMO as provided in the Grid Code including the provision of ancillary services such as frequency regulation or voltage support, this may attract dispute from the Market Participants claiming that its Imbalance due to action of System Operator and it shall not be penalized to pay for higher System Marginal Prices.

  Therefore, it is important that necessary regulatory directions shall be issued to the System Operator that specify the parameters under which a cheaper Generator can be partially loaded, and the Market Participant shall be compensated for any loss in such a case by the whole market as provided in the Commercial Code.

iii. The Report also notes that in public hearings for FCA, the Authority doesn't allow deviations from Economic Merit Order (EMO) from time to time and also disallows any cost incurred on account of deviation from EMO to be passed on to the consumers and instead has charges such cost to the NTDC. It is therefore, necessary that the Authority may determine parameters for deviation from EMO in light of the provisions of the Commercial Code and Grid Code and specify which deviations from EMO will qualify for compensation as other market charges including Ancillary Services and which deviations will be charged to the NTDC or System Operator, as the case may be.

B. **Discussion:**

- NPCC representative, for the purpose of the clarity of the participants, enquired about the difference between congested zones and congested areas. He added that currently there are only two zones, KE and the rest of Pakistan. It was clarified that congested areas are those areas within the system for which SO has to allow dispatch of out-of-merit plants to alleviate the congestion. A congestion zone is envisioned as an independent network such as KE, Gwadar and rest of Pakistan.

- Further in this regard, it was also deliberated that the System Operator will provide a report to NEPRA as per the Commercial Code incorporating the details of the congestion and the plants that may be required to be dispatched to alleviate congestion. NPCC representative further added that the Grid Code also require ASRAIR report which provides the same information, so this requirement is in line with the Grid Code. It was apprised that the requirements established in the Commercial Code can be extracted from the ASRAIR report by the System Operator for onward submission to MO.

  The participants agreed that once the congested areas and zones are approved by the regulator, it will provide an objective mechanism or parameters under which the System Operator can deviate from the economic loading of generators under ideal conditions. These parameters will also avoid disputes by the market participants.

- NPCC representative highlighted that due to certain operational constraints, NPCC has to make a dispatch considering not only the Merit Order list or the EMO (as mentioned in the Final Report) but also several constraints of the system including transmission, number of startups etc. Hence this process is called the Security Constrained Economic Dispatch, as SO has to ensure reliable and secure dispatch while on the other hand making it as economic as possible. It was suggested and agreed that the word EMO will be replaced with SCED in the Final Report.

- The forum deliberated that deviation from Merit Order can occur due to various entities such as DISCOs, NTDC or SO. It is necessary to determine that in such cases, can the cost be charged to NTDC or any other entity.

C. Conclusion:

- It was agreed that the System Operator will define congested areas within 3 months of CMOD as recommended in the revised Commercial Code, as this is also in line with the Grid Code requirements.

- It was also agreed that System Operator will provide the quantum of energy (KWh) to compensate for Ancillary Services and other market charges as it already provides the input parameters for this calculation.

- As discussed above regarding Authority's decisions on not allowing certain costs during the FCA hearings, be highlighted before the Authority for amicable resolution.

4. Commercial Allocation

A. Explanation:

- The forum was apprised that the commercial allocation factors provided in Market Commercial Code are to be used for mainly three purposes. i) Planning; ii) Imbalances and iii) Capacity Invoices. It was further explained that commercial allocation factors will be updated based on historical capacity invoices of the previous three years as it was agreed in the earlier consultative workshops with DISCOs and other stakeholders. The report notes that the commercial allocation factors calculated on historical capacity invoices shall be used for planning purposes and energy imbalances only.

- For Capacity Invoices issued to the DISCO by the Special Purpose Agent (SPA) for legacy generators, the following transition shall be adopted for calculation of the Allocation Factors:

  - At least three (3) years of coincidental MDI data shall be used for calculation of the Allocation Factors.

  - Installation of Commercial Metering System as per provisions of the Commercial Code and Grid Code on all Metering Points especially the Metering Points between PESCO and TESCO.

  Once the Allocation Factors are calculated on the coincidental MDI data, then the same factors shall be used for all of the above three purposes as stated above.

- It was further highlighted that one of the stakeholders has recommended that there shall be separate allocation factors for planning and for energy imbalances. The factors of planning shall be based on historical capacity invoices while the factors for energy shall be based on historical energy invoices as already calculated by the Market Operator.

C. Conclusion:

- It was agreed that the System Operator will define congested areas within 3 months of CMOD as recommended in the revised Commercial Code, as this is also in line with the Grid Code requirements.

- It was also agreed that System Operator will provide the quantum of energy (KWh) to compensate for Ancillary Services and other market charges as it already provides the input parameters for this calculation.

- As discussed above regarding Authority's decisions on not allowing certain costs during the FCA hearings, be highlighted before the Authority for amicable resolution.

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  Once the Allocation Factors are calculated on the coincidental MDI data, then the same factors shall be used for all of the above three purposes as stated above.

- It was further highlighted that one of the stakeholders has recommended that there shall be separate allocation factors for planning and for energy imbalances. The factors of planning shall be based on historical capacity invoices while the factors for energy shall be based on historical energy invoices as already calculated by the Market Operator.

- It was further discussed that there is also an opinion whether energy imbalances shall be calculated in case where the System Operator has allocated different quantum then the commercial allocation factors due to a directive from competent authorities.

- Furthermore, as given in the Final Test Run Report, the implications of commercial allocation on suppliers of last resort were discussed w.r.t. end-consumer tariff. The queries mentioned in the report w.r.t. imbalances and their reflection in the base tariff, their frequent adjustments as part of monthly fuel cost adjustments and related matters and their modalities were elaborated.

B. <u>Discussion:</u>

- It was highlighted that the commercial allocation issue has already been discussed at length in previous consultative sessions and thus the recommendations shall remain the same as of previous.

- The recommendation to calculate energy imbalances only based on allocation factor derived from last three years energy consumption was not agreed. The participants resorted to the decisions and agreements made in the previous consultative sessions. It was apprised that the final report also notes the same recommendations as were agreed in the earlier consultative sessions as explained above.

- NPCC representative discussed that at the time of capacity shortages, the allocation of the power from the pool is not based on any specific criteria such as the commercial allocation, however, it is based on the specific instructions of the competent authorities considering the line losses of different DISCOs. The DISCOs with higher losses will curtail more power as compared to the DISCOS with lower losses. So this can happen that one of the DISCOs will lower loss may be allocated more quantum than its commercial allocation and it may withdraw it as such.

- DISCO representative argued that if any DISCO withdraws more than its commercial allocation, then it shall be charged for such imbalance. The reason for creation of such imbalance is irrelevant and the benefit is distributed among all the DISCOs including the DISCO creating the imbalance.

- The forum also proposed to add the transitory mechanism in the Final Test Run Report as agreed in the previous consultative session held in October 2022. It was apprised that the same has already been reflected in the Final Test Run Report.

- With regard to the queries as mentioned above in the explanation part, the participants discussed that the imbalances are being determined and charged to the DISCOs as per the approved Commercial Code by NEPRA, they are not inefficiencies and therefore, they should be passed on to the consumers of last resort suppliers. Similarly, although to the knowledge of the participants, NEPRA has conducted discussions on such tariff related matters w.r.t. CTBCM including charging of imbalances to consumers and their periodic adjustments thereof, it is imperative that the final report should highlight this as an important point to be addressed by the Regulator.

C. **Conclusion:**

- It was agreed by the forum that allocation factor based on the capacity invoices of the last three years shall be used for planning as well as energy imbalances.

- It was agreed by the forum that the energy imbalances shall be calculated and charged even if the System Operator has allocated different quantum under any directives of the competent authorities.

- It was suggested by the participants that the tariff related matters w.r.t. charging of imbalances to consumers and their adjustments thereof may be communicated to NEPRA through Final Test Run Report for consideration and adjustment of regulatory framework.

5. Annual Settlement Statement:
D) Excess Losses of Transmission Service Providers

A. **Explanation:**

- It was explained that that the approved Commercial Code for test-run stipulates that the actual loss during any hour shall be charged to the Market Participants. Besides that, a mechanism was included in the Commercial Code for determination of any excess losses beyond the benchmark as set by the Authority for any Transmission Service Provider.

- It was further deliberated that during the trial run, it was observed that the losses are a bilateral matter between the Market Participants and the Transmission Service Providers, and the Market Operator shall not be involved in transaction related to treatment of any excess losses beyond the benchmark set by Authority. Therefore, it is recommended that mechanism for treatment of any excess losses beyond the benchmark as set by the Authority for any Transmission Service Provider may be removed from the Commercial Code.

B. **Discussion:**

- The details of excess losses treatment were discussed at length. In the discussion, it was apprised that the transmission losses in the imbalances will be small portion of excess losses (if any) that the DISCOs will transact with NTDC bilaterally for their overall contracted amount. Therefore, it was discussed and agreed that same treatment of excess losses should be exercised either for imbalances or for the contracted quantities. As for the contracted quantities, the entities deal directly with transmission company without the involvement of Market Operator, this amendment will only make things consistent and practical.

C. Conclusion:

- The forum agreed with the proposal of the Final Test Run Report and suggested that NEPRA may reflect the treatment of excess losses in the relevant regulatory instrument.

iii) Balancing Mechanism for Capacity

A. Explanation:

- It was apprised to the participants that as explained in the final test run report, due to non-availability of coincidental MDI data, the readiness of the System Operator to determine the input parameters of the BMC etc., it is recommended that the trial run of the BMC shall be extended for three years without having any financial implications so that that improvements can be made before its actual implementation.

B. Discussion:

- The forum sought clarity regarding the impact of this trial extension on market discipline. It was deliberated that the DISCOs have excess capacity and BMC might not have significant impact on DISCOs in near future. It was further added that the first transaction is only practical after 1-1.5 years of CMOD.

- It was responded that the application of stranded cost, cross subsidy, and availability of excess capacity with SOLRs will mitigate risks. If the private players in the market are not able to fulfill their capacity obligations, they will be buying energy through imbalances which will be charged at marginal price as opposed to average price. This will encourage all private market participants to ensure compliance to their capacity obligations.

C. Conclusion:

- It was concluded by the forum that the NEPRA may be requested vide the Final Test Run Report that for extension of the BMC test run for further three years.

6. Merit Order Application and System Marginal Price

A. Explanation:

- The participants were apprised on the status of the Merit Order Application that the application has been developed, tested, and deployed. The IPPs will be providing fuel stock information on daily basis based on which, economic merit order development shall be on daily basis as opposed to fortnightly being done today. However, for the purposes of payments under PPA, the Authority determines the actual Fuel Cost Component (FCC) of all such IPPs on monthly basis as average of the operations during a month. The hourly variable cost may be higher or lower than the Authority's determination as mentioned above.

- The scenarios as per the table given in the Final Test Run Report was elaborated. It was explained that under the CTBCM, the difference between the Marginal Price and adjusted Fuel Cost Component (which is done later on) will be borne by the parties to the bilateral contract. It can be the case in which the adjusted Fuel Cost Component of the plant setting the Marginal Price is lower than the Marginal Price or the adjusted Fuel Cost Component of the plant setting the Marginal Price is higher than the Marginal Price.

- It was also highlighted that the discussion on this particular matter of the difference between the Marginal Price and adjusted Fuel Cost Component was carried out with the NEPRA Team during Test Run.

B. <u>Discussion:</u>

- While the participants appreciated the efforts to bring the Merit Order on daily basis, NPCC representative highlighted that due to certain operational constraints, NPCC has to make a dispatch considering not only the Merit Order list but also several constraints of the system including transmission, number of startups etc. Hence this process is called the Security Constrained Economic Dispatch, as SO has to ensure reliable and secure dispatch while on the other hand making it as economic as possible.

- It was further discussed that the preparation of merit order on daily basis will improve the dispatch and bring transparency into the system and help identify operational constraints as well as true marginal price discovery.

- The queries of the participants to build their understanding on the differences that may come between the Marginal Price and adjusted fuel cost component were answered to their satisfaction.

C. <u>Conclusion:</u>

- The forum agreed that as mentioned in the final test run report, in order to cater for the differences of the values used in determination of Marginal Prices and the actual FCC for the bilateral payment, the Authority may address the matter in its regulatory framework.

PART-II: Discussion on the Entire Report

- Subsequently, the forum was opened before the participants to offer their key comments that require discussion/clarity. Henceforth, the comments received from the implementing entities and the response/clarity provided by CPPA are recorded in the sequence of discussion:

1. Feedback from NTDC as TNO, MSP and SO

- **Comment # 01:** System Operator representative commented that the new proposed formulation of firm capacity which is benchmarked on the Annual Dependable Capacity (ADC) is not suitable as ADC is not reflective of the actual capacity available during the system peak hours as plants may be unavailable due to unforeseen reasons. It was deliberated that the use of Annual Dependable Capacity (ADC) in the calculation of firm capacities will result in non-reflective capacity obligations. It was further recommended that technical availability and practical availability (based on fuel constraints) should be considered separately. It was recommended by the SO representative that the existing methodology in the approved Commercial Code be maintained.

- **Response:** It was explained that the new methodology caters for the issues highlighted by the SO as the old methodology of calculating firm capacity only considered the availability of thermal plants irrespective of fuel constraint or otherwise. It will be construed unfair to reduce firm capacity of generators due to unavailability of fuel as arrangement of fuel is buyers' responsibility in legacy PPAs. Moreover, even if special provisions allow the legacy PPAs to receive firm capacity certificates for the period and quantity unavailable due to fuel constraint, it will be unfair with the market generators as their firm capacity certification methodology will become different from legacy generators. Hence, because of this and some other reasons, it was considered more appropriate to change the firm capacity certification methodology.

- **Comment # 02:** It was commented by System Operator representative that as per the approved design, new entrants in the market are expected to provide their variable cost to the SO for the formulation of Merit Order. As the variable cost for legacy plants is already being provided by SPA, the SO will consolidate both in future. SPA being the custodian of the PPA signed with legacy generators, it is SPA's responsibility to provide the variable cost and as such SPA should be also the custodian of Merit Order Application with the onus of verification parked on SPA's end and the application shall be housed at CPPA as part of CDXP.

- **Response:** It was explained that SPA has a fixed formula related to the variable cost determination under each PPA considering heat rate, degradation factor, fuel inventory management formulation and exchange rate etc. That formula has been configured in the Merit Order application and to the extent of configuration of formulas the responsibility lies with CPPA. It was further clarified that the responsibility of providing variable cost lies with the generator while bearing the risk associated with the provision of incorrect cost and neither MO nor SO should be held responsible for this verification of the submitted cost. Furthermore, SO will only be responsible up to the extent of data verification and sanity check. Moreover, it was also agreed that the issue of housing the Merit Order Application requires further deliberation and would be taken up separately.

- **Comment # 03:** The System Operator representative also highlighted that no procedure is in place to verify the variable cost of the plants entering the market after CMOD. It was further pointed out that there should be a SOP in place pertaining to this matter to provide clarity. SO may raise flags if it considers that a submitted variable cost is incorrect, however, further verification of the reported statistics may be performed by the Market Governance and Monitoring Unit of the NEPRA.

- **Response:** It was discussed that procedure to verify the variable cost of plants entering the market after CMOD should be elaborated for clarity. Moreover, it was also clarified that the actual verification of variable cost, when flagged by the System Operator or otherwise, may be performed by the Market Governance & Monitoring Unit of NEPRA with the assistance of System Operator.

- **Comment # 04:** NTDC TNO representative stated that in case of a default, it would not be possible for the TNO/DNO to immediately disconnect a load from the network as it will have implications on the overall system stability and would require a time.

- **Response:** It was explained that the language of the Commercial Code does not require immediate disconnection. Rather it provides a date in terms of number of days to TNO/DNO for disconnection after the event of the default. In cases where additional time is required for physical disconnection, the MO will consult the disconnection timelines with respective TNO/DNO and will discuss the modalities before its issuance. However, once a disconnection notice is issued after finalization of an agreed date and physical disconnection does not occur on the communicated date, any energy consumption beyond the disconnection date will be charged to the respective TNO/DNO.

2. Feedback from DISCOs

- **Comment # 05:** Apart from the inputs provided on the key issues above, GEPCO team suggested that the Commercial Code amendments presented in the report may be sequenced in line with the sequence of the Commercial Code, and actual clauses may be copied against the respective amendment for ease of understanding.

- Response: CPPA responded that sequencing and consistency as suggested will be ensured in the Final Test Run Report where required. Furthermore, proper referencing will be added in the text of the report where applicable.

- **Comment # 06:** GEPCO team commented that until the principles of Allocation Factors are approved as recommended in the Final Test Run Report, clarification is required as to what allocation factors will be considered for calculation purpose from now until the approval. It was further suggested that even after the approval of the principles by the Authority, the new allocation factors may be approved by CCRP each time when there is a change in the same.

- **Response:** It was explained that the allocation factors provided in approved Commercial Code will be used till the time new principles are approved. However, the same may be revised from time to time considering historical capacity invoices based on non-coincidental MDI. Similarly, once the historical co-incidental MDI data is available, the allocation factors will be revised accordingly. Moreover, it was clarified that the relevant forum for the approval of the allocation factors based on the principle given in the Commercial Code is CCRP, which will be activated once the revised Commercial Code is approved by the Authority. Once the CCRP is activated, the allocation factors, whenever revised, will be approved by the Panel.

- **Comment # 07:** GEPCO team further pointed out that the definition of the critical hours shall be reviewed again to ensure that 11 hours are included in a single day and the time slots may also be redefined.

- **Response:** It was responded that the discrepancy will be rectified accordingly.

- **Comment # 08:** GEPCO representative highlighted that w.r.t investment preparation, planning etc. different regulations have different action dates which requires alignment. IESCO further added that timelines in the regulatory calendar starting from demand forecast preparation to the submission of Multi Year Tariff (MYT) need to be aligned.

- **Response:** It was clarified that comments on the regulatory framework, if any, may be highlighted directly before NEPRA in formal correspondence.

- **Comment # 09:** GEPCO representative recommended that the Market Operator should be involved in the calculation of excess transmission losses.

- **Response:** It was explained that the issue has been deliberated in detail (as noted under Part-I) and consensus of the forum has been developed in this regard.

- **Comment # 10:** TESCO representative commented that the reserve margin must be revisited to ascertain whether 10% reserve margin is suitable or not.

- **Response:** It was apprised that the matter has already been highlighted in the Test Run report. As such, 10-15% is a safe estimate as per the international best practices, and as per the Commercial Code, the actual percentage of reserve margin will be established by System Operator in future.

- **Comment # 11:** MEPCO representative suggested that the column of "other charges" in the Settlement Statements should be further elaborated.

- **Response:** It was agreed that the relevant details will be included accordingly in the Settlement Statement for clarity of purpose.

- Other DISCOs also mentioned that their points have already been discussed by other DISCOs and they have no further comment to offer.

3. Feedback from K Electric

- **Comment # 12:** KE expressed its limitation that until the KE Integration Plan is approved, they are unable to express their true feedback on the Test Run Report. Keeping this in view, they requested for separate deliberations with CPPA and NEPRA after the approval of KE integration plan.

- **Response:** The request for separate deliberations after the approval of KE Integration Plan by NEPRA was agreed by CPPA.

15/6

Omer Haroon Malik
Head Market Operations & Development
CPPA-G

CPPA

Annexure-1
List of Participants

NTDC

- Mr. Muhammad Sohaib, Chief Engineer
- Mr. Tariq Mehmood, Manager MSP
- Mr. Muhammad Sarmad Ahsan, Deputy Manager
- Mr. Bilal Aslam, Manager PMU
- Mr. Salman Gul, Deputy Manager SO
- Mr. Jawaid Rehman, Manager IT
- Mr. Umer Ahsan, Deputy Manager

K-Electric

- Mr. Mudasir Zuberi, Head of Business Development
- Mr. Fahad Mazhar, General Manager
- Mr. Sameer Hassan, General Manager
- Mr. Hamza Jamal, Manager Regulatory Affairs

MEPCO

- Mr. Mian Ansar Mahmood, Chief Financial Officer
- Mr. Muhammad Sohail Ahmed, DG MIRAD
- Mr. Shoukat Hussain, Manager MIRAD
- Mr. Qaiser Abbas, Manager MIRAD (Online)

GEPCO

- Mr. Iyaz Ahmed, Chief Financial Officer
- Mr. Irfan Rafique Butt, DG MIRAD
- Mr. M. Muhammad Junaid, Manager MIRAD
- Mr. Ahmed Furqan, AM MIRAD

FESCO

- Mr. Nazir Ahmed, Chief Financial Officer
- Mr. Muhammad Amir, DG MIRAD (Online)

- FESCO MIRAD Team (Online)

LESCO

- Mr. Altaf Qadir, DG MIRAD
- Mr. Muhammad Atif, Director Finance
- Mr. Muhammad Basharat, Manager MIRAD
- Mr. Kamran Masood Khan, Deputy Manager MIRAD
- Mr. Faheem Iqbal, AM MIRAD
- Mr. Ahmad Yousaf, AM MIRAD
- Mr. Ammar Kharal, AM MIRAD

IESCO

- Mr. Fazal e Wahab, Finance Director
- Mr. Hammad Amer Hashmi, DG MIRAD
- Mr. Awais Ali, Deputy Director MIRAD
- Mr. Salman Khan, Deputy Director MIRAD

PESCO

- Mr. Atif Jawad, DG MIRAD
- Mr. Muhammad Shakeel, Director Legal
- Mr. Umer Iftikhar, Manager MIRAD
- Mr. Amjad Islam, DM MIRAD

QESCO

- Mr. Yasir Faheem, Finance Director / Acting DG MIRAD
- Mr. Muhammad Zulqarnain, Manager MIRAD
- QESCO MIRAD Team (Online)

SEPCO

- Mr. Khalid Hussain Shaikh, Acting DG MIRAD MIRAD
- Mr. Imdad Ali, Finance Director (Online)
- SEPCO MIRAD Team (Online)

IESCO

- Mr. Moazzam Hussain, Finance Director
- Ms. Huma Ghazal, DG MIRAD
- Mr. Rehan Ahmed, Deputy Director MIRAD
- Ms. Rabia Kalsoom, Deputy Director MIRAD
- Mr. Sheraz Ahmed, Deputy Director MIRAD

HESCO

- Ms. Natasha Shaikh, Dy. Manager MIRAD (Online)
- Mr. Muhammad Nouman Sohu, AM MIRAD (Online)
- Mr. Habib M. Hassan, AM MIRAD (Online)

USAID / PSIA

- Mr. Abid Latif Lodhi, Director PSIA

CPPA

- Mr. Omer Haroon Malik, Head MOD
- Mr. Syed Shaheer Ali, Manager Market Services
- Mr. Farooq Qurban, Manager Design & Simulation
- Mr. Ahmad Qazi, Manager Design & Product Development
- Mr. Arshad Khan, Manager Finance
- Mr. Abid Rizvi, Manager Legal
- Mr. Abrar Hussain, Deputy Manager Design & Product Development
- Mr. Usman Khalid, Assistant Manager