



Registrar

# National Electric Power Regulatory Authority

## Islamic Republic of Pakistan

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No. NEPRA/Advisor(CTBCM)/NCM-02/16545-71

October 15, 2025

Chief Executive Officer,  
Independent System and Market Operator (ISMO) of Pakistan,  
ISMO Building, Pitras Bukhari Road,  
H-8/1, Islamabad

Subject: **DETERMINATION OF THE AUTHORITY IN THE MATTER OF CTBCM FINAL TEST RUN (FTR) AND APPROVAL OF THE MARKET COMMERCIAL CODE**

Enclosed please find herewith Determination of the Authority (total 53 pages) alongwith Market Commercial Code 2025 (total 208 pages) in the matter of CTBCM Final Test Run (FTR) and approval of the Market Commercial Code.

Enclosure: **As above**

*Wasim Anwar Bhinder*

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Copy to:

|     |                                                                                                                                                                            |     |                                                                                                                                                          |
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**Determination of the Authority in the matter of CTBCM Final Test Run (FTR) and Approval of the Market Commercial Code**

**1. Background**

- 1.1 The Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 (the NEPRA Act) as amended in 2018, provided the legal framework for the development of a competitive electric power market in the country.
- 1.2 For the purpose of the development of a competitive electric power market, the Authority initially issued Certificate of Registration No. MOR/01/2018 to the Central Power Purchasing Agency (Guarantee) Limited (CPPA-G). The said registration authorized CPPA-G to undertake preparatory functions for competitive market operations, including the development and submission of a model for competitive market design to the Authority for approval.
- 1.3 Pursuant to this mandate, CPPA-G submitted the Competitive Trading Bilateral Contract Market (CTBCM) model, which was duly considered and approved by the Authority through its determinations dated December 05, 2019 (High-level design) and November 12, 2020 (Detailed design). In furtherance thereof, the Authority, through its determination dated May 31, 2022, granted the MO licence to CPPA-G, authorizing it to act as the MO.
- 1.4 In terms of Article 28 of the MO Licence and paragraph H(iii)(c) of the determination dated May 31, 2022, the Authority obligated the MO to undertake a six (06) month test run of the market. The test run was intended to test and implement, without financial implications, the Market Commercial Code (MCC) together with the processes, IT systems, and methodologies developed thereunder.
- 1.5 Upon completion of the test run, the MO was required to submit to the Authority a comprehensive Final Test Run (FTR) report, along with proposed amendments in the MCC for consideration and approval. The MO submitted the said report, along with proposed amendments to the MCC, on December 28, 2023 thirteen (13) months after the expiry of the stipulated period. The Authority has taken note of the explanation provided by the MO that on account of several reasons including seeking approval of the Cabinet Committee on Energy, the submission of the FTR report was delayed.
- 1.6 It is a matter of record that the Authority, vide determination dated April 30, 2025, transferred the MO licence from CPPA-G to newly incorporated the Independent System and Market Operator of Pakistan (Guarantee) Limited (ISMO). Accordingly, where the context so permits, the MO has been referred to as the ISMO.







## **2. Comments of the Stakeholders**

- 2.1 The Authority considered the FTR report and proposed amendments in the MCC and decided to solicit comments on the same from the general public and the stakeholders.
- 2.2 A notice seeking comments from the stakeholders was published in one (01) English and one (01) Urdu daily newspaper on January 12, 2024. Additionally, separate letters were also sent to relevant stakeholders soliciting their input/views.
- 2.3 In response, comments were received from the following stakeholders namely All Pakistan Textile Mills Association (APTMA), Arzachel Pvt. Limited (Arzachel), Gul Ahmed Energy Limited (GAEL), K-Electric Limited (KE), Multan Electric Power Company (MEPCO), Pakistan Association of Large Steel Producers (PALSP), Amreli Steels, Board of Investment (BOI), Punjab Power Development Board (PPDB), Pakistan Atomic Energy (PAEC), National Power Control Center (NPCC/SO) of the National Transmission & Despatch Company (NTDC, now NGC), and Korangi Association of Trade and Industry (KATI), Khyber Pakhtunkhwa Textile Mills Association (KPTMA). The Authority also sought rejoinder of the MO on the comments of these stakeholders.
- 2.4 The comments of the stakeholders and rejoinder of the MO on the same are summarized in the following sub-paragraphs:

2.4.1 APTMA supported CTBCM for its potential to lower electricity costs, facilitate transition to net-zero, and preserve export competitiveness. It cautioned against burdening CTBCM with stranded costs or legacy inefficiencies that could make B2B contracts unviable and urged protection of legacy wheeling contracts and inclusion of hybrid consumers. APTMA argued CTBCM would not collapse DISCOs, which are already failing to meet regulatory standards, but could improve their performance by shifting some demand away from the regulated sector, allowing DISCOs to better serve their remaining consumers. It stressed transparency and real-time data access as essential to avoid delays and cost distortions. Finally, APTMA emphasized the need for structural reforms, including separation of wires and supply businesses, to address circular debt, contending that CTBCM with such reforms would stimulate growth, reduce inflation, lower circular debt, and create fiscal space for welfare measures.

2.4.2 In response, MO acknowledged APTMA's support for CTBCM implementation and emphasized that stranded costs are a legitimate concern recognized during CTBCM's design. It clarified that these costs, equivalent to capacity charges of legacy generators, would be borne by consumers opting for open access. MO recalled that a 2019 committee had recommended socializing such costs among all consumers to minimize the burden. It reiterated that legacy contracts would continue unaffected, the hybrid consumer model has not been adopted in the design of the market, and bilateral contracts using the national grid must align







with CTBCM within one year. MO confirmed that transparency measures, including requiring mandatory publication of information by all market players, are in place for data access. It noted that the separation of wire and supply was desirable but not essential for market roll-out, citing global precedents. MO further underlined CTBCM's expected benefits in fostering competition, creating jobs, reducing circular debt, and improving efficiency, while clarifying that proposals to ignore stranded costs were not feasible.

- 2.4.3 Arzachel proposed a Market Governance and Monitoring Unit for transparent market oversight and conflict resolution among participants, the MO, and the System Operator (SO). It stressed supply reliability for Bulk Power Consumers (BPCs), urging penalties for network unavailability based on Value of Lost Load and alignment with SAIDI/SAIFI standards. On the Balancing Mechanism for Capacity (BMC), it suggested beginning CTBCM with energy trading, redirecting generation investments to transmission, and introducing a Capacity Remuneration Mechanism, while supporting shorter Merit Order intervals. It recommended daily automation of Economic Merit Order (EMO) deviations with real-time inputs to ensure Security Constrained Economic Dispatch (SCED) compliance, issuance of guidelines on partial loading of generators, and clear rules for compensating such generators as well as must-run generation and Ancillary Services with SO tasked to identify congested zones.
- 2.4.4 Arzachel further proposed that high System Marginal Price ("SMP") from congestion be mitigated through targeted transmission investments, with delays beyond three years borne by the relevant Transmission Network Operator ("TNO"). It called for monitoring systems to detect and penalize deviations, benchmarks for NGC and DISCO consumption, removal of excessive T&D loss pass-through with mandatory annual improvements, and joint SO/MO accountability for SMP increases. It also urged a stronger SO role in congestion management, replacement of FCA with a unified monthly energy adjustment for consumers of Suppliers of Last Resort ("SoLR"), alignment of quarterly adjustments with capacity imbalance settlements, penalties for procurement deviations, transparency on MO's data storage and security, and public access to Commercial Code Operational Procedures ("CCOPs") for prospective participants.
- 2.4.5 In response, MO agreed on the importance of a Market Monitoring Unit under NEPRA to ensure transparency and prevent anti-competitive practices. It clarified that reliability standards and penalties already fall under the Grid/Distribution Codes and NEPRA's regulatory mandate. CTBCM, it explained, rests on two products, Energy and Capacity, ensuring efficiency and reliability, with capacity adequacy to be tested in the BMC. While Arzachel's proposal for CRM was noted, MO observed that such mechanisms are typical in energy-only markets.







MO agreed to prepare Merit Orders on a shorter duration basis in coordination with SO, while reiterating that SCED procedures and compensation mechanisms are already fully embedded in the MCC. On excess transmission losses, MO pointed to its FTR recommendation for NEPRA to address the issue, while noting amendments in MCC regarding congested zones. Tariff adjustments, it clarified, remain within NEPRA's remit. On IT concerns, MO assured that certified protocols, secure servers, and restricted access mechanisms are in place. Further, the MO confirmed that CCOPs will be made publicly available.

- 2.4.6 GAEL supported CTBCM and recommended attracting new entrants through streamlined regulations and financial incentives together with reform of capacity payments to encourage efficiency and reduce costs. It urged resolution of technical issues in the trading platform, improvements in data access, investment in grid infrastructure, and adoption of robust cybersecurity. GAEL emphasized finalization of the Use of System Charges (UoSC) mechanism as essential, recommending a clear methodology, periodic adjustments, elimination of cross-subsidies, and cost-reflective tariffs, with UoSC capped at PKR 3/kWh subject to 10% annual escalation. It further proposed MCC amendments to facilitate bilateral contracting, ensure transparency, and institutionalize stakeholder engagement, coupled with the phased implementation of CTBCM. GAEL stressed clarity on the Use of System Agreement (UoSA), reflecting actual usage costs, excluding transmission charges for Karachi-based plants, and addressing omissions in Connection Agreements regarding grid unavailability, loss pricing, and DISCO penalties. It opposed DISCO-favored clauses, recommended pre-determined UoSC indexation, and emphasized transparent and predictable arrangements to build investor confidence.
- 2.4.7 In response, MO acknowledged GAEL's proposal for attracting participants and reforming capacity payments but clarified that such payments are policy matters of the Federal Government. It confirmed that NEPRA is finalizing the UoSC mechanism transparently, with hearings and data disclosure, and a dispute resolution mechanism has already been approved. Regarding tariffs, MO observed that socio-economic conditions necessitate limited cross-subsidization under the NEPRA Act, though Government policy aims to reduce these over time. UoSC will reflect actual costs and apply uniformly across KE and NGC systems until transition to nodal pricing. Fixing UoSC at PKR 3/kWh, it held, would unduly burden remaining consumers. MO further commented that draft UoSA and Connection Agreements have already been submitted for regulatory approval
- 2.4.8 KE submitted that several areas in the FTR report require further deliberation, particularly stranded costs and cross-subsidy surcharges, and urged holistic consultations with stakeholders before finalizing these matters. It emphasized the need for capacity-building prior to CTBCM rollout. With respect to the Balancing







Mechanism for Energy (BME), KE sought clarity, with illustrative examples, on the calculation of imbalances, including treatment of generation from KE plants, IPPs contracted with KE, merchant plants, and BPCs. KE further submitted that auxiliary consumption of NGC grids should be charged directly to NGC rather than DISCOs, that T&D losses in inter-DISCO transactions be borne by the recipient DISCO, and that NGC transmission losses be reflected in BME calculations subject to tolerance limits, proposing 10% above contracted interconnection capacity.

- 2.4.9 For imbalances in the regulated market, KE proposed pass-through in tariffs. It understood that security cover requirements would apply only once MO is established as a separate entity and requested consultations on their design. KE referred to its pending integration plan under NEPRA's review, noting its role as Metering Service Provider (MSP). It proposed that out-of-merit costs be borne by SO, that take-or-pay obligations be reflected in SoLR tariffs, and that congestion zones be identified for out-of-merit compensation. KE sought clarity on the treatment of excess transmission losses omitted in the revised MCC, on ex-ante capacity obligations (including application of CAGR formula), and requested extensions in data submission timelines.
- 2.4.10 On MCC, KE submitted that its allocation factor should remain fixed under its Power Purchase Agency Agreement (PPAA), and capacity charges be levied uniformly on an MDI basis across SoLRs, with any changes requiring consultation. It reiterated the need for clarity, with examples, on proposed amendments in the BME mechanism and system peak hour definitions, stressing alignment with KE's actual load profile. KE also sought clarity on the definition of legacy contracts, treatment of must run generation and Ancillary Services once congestion zones are identified and requested extended timelines for MSP submissions.
- 2.4.11 Further, KE stressed that any changes to the firm capacity determination mechanism should align with its generation tariff and requested proper consultation through the CCRP forum. It sought clarity on dependable capacity and forced outage rate calculations. It highlighted the omission of a compensation mechanism for excess transmission losses, requested consultation on disconnection procedures under the MCC, clarification of CAGR formula for capacity obligations in later years, recognition of voltage support as a distinct ancillary service, and consideration of nuclear generation as zero fuel cost. KE submitted that any modification in billing, including replenishment, set-off, or application of amounts against outstanding debts or penalties, should be effected through mutual agreement between the MO and the Market Participant concerned, rather than by unilateral action of the MO. KE also commented that the financial burden from a defaulting Market Participant should not be shared among all







Market Participants but borne by the respective defaulter to avoid additional financial burdens on regulated consumers.

- 2.4.12 In response, MO provided that CTBCM is a major reform being pursued through extensive consultation, with pending matters like UoSC in final stages. Capacity building sessions, including KE-specific training, have been conducted. MO confirmed KE's view that auxiliary consumption should be charged to NGC. On inter-DISCO losses, it recorded that stakeholders agreed to continue legacy practice for the time being. Further, MO clarified that security cover/settlement guarantee cover is calculated under MCC methodology, though not required for DISCOs until bilateral contracts are signed. KE, however, will have security cover calculated based on expected imbalances until integration. MO further clarified that procedural details of different matters are covered under CCOPs. It also clarified that KE must enroll as Market Participant and Service Provider, with obligations similar to other DISCOs.
- 2.4.13 On commercial allocation, MO confirmed that KE remains governed by its PPAA and is unaffected by amendments applicable to DISCOs. System peak hours were based on NGC data, but KE's data may be incorporated upon integration. KE's generation will continue as legacy generation under separate definitions, with registration of legacy contracts requiring NEPRA's prior approval. MO reiterated that CCRP processes apply only post-CMOD, and CCOPs have already been prepared. On excess losses, MO clarified that these are regulatory matters outside MCC. Further, MO clarifications that CAGR-based capacity obligation determination, treatment of nuclear generation as zero fuel cost purposes, and confirmation that disconnection and default procedures are fully embedded in MCC.
- 2.4.14 MEPCO submitted that it had verified and communicated the exact locations and number of CDPs to the MO and disagreed with the legacy arrangements for inter-DISCO CDPs. It proposed that both transformation and transmission losses be charged to the receiving DISCO in line with NEPRA-approved percentages of the sending DISCO, irrespective of the direction of flow. It further recommended amending the definition of system peak hours, suggesting 12:00–17:00 and 10:00–01:00 in place of 21:00–01:00, and advised using average invoices of the last three fiscal years of DISCOs for clarity among participants. MEPCO emphasized that the MO must assume responsibility for resolving issues between participants and metering service providers, and recommended updating, rather than deleting, details of the initial security cover of Ex-WAPDA DISCOs to reflect SPA payments.
- 2.4.15 MEPCO proposed amending the MCC to determine Firm Capacity for thermal units on a unit basis, and that de-rated legacy contracts should be revised







accordingly. It also noted that the FTR failed to address the practical application of NEPRA's 2022 Open Access Regulations, including balancing, banking, and equity payment modes.

- 2.4.16 In addition, MEPCO highlighted ambiguities concerning new institutions introduced under CTBCM such as the MIMG and SPA whose roles and procedures for managing and transferring legacy contracts remained undefined. It noted that the FTR report omitted settlement of existing wheeling contracts despite its request for inclusion in settlement statements. Finally, MEPCO pointed to persistent discrepancies between units and MDI reported by it and those charged by the MO in settlement statements.
- 2.4.17 Regarding the comments of MEPCO, MO confirmed receipt and validation of CDP information but did not agree with continuing legacy practice for inter-DISCO losses. It responded that proposed peak hours reflect true demand patterns. Further, MO emphasized that hard-coded figures would be problematic; hence, criteria are included in MCC with periodic publication by MO. Metering disputes, it clarified lie within NEPRA's jurisdiction and MSP's domain. Wheeling Regulations, 2016 stand repealed, and old contracts must conform to the Open Access Regulations, 2022. MO noted MEPCO's non-provision of hourly data, which hindered inclusion in settlement statements. It reiterated that sovereign-to-financial guarantee transition is a long-term goal, not part of the trial run.
- 2.4.18 PALSP and Amreli Steels submitted that SoLRs should declare their annual demand to the Regulator, SO, and MO on a monthly rollover basis with a  $\pm 10\%$  deviation margin, with excess deviations not passed on to consumers. They proposed replacing FPA/FCA with Monthly Tariff Adjustments based on each DISCO/SoLR's monthly energy imbalance, while shifting quarterly tariff adjustments to a half-yearly or annual capacity balancing mechanism. They further suggested that DISCO imbalances be calculated within defined margins and shared equally among consumers to preserve a uniform national tariff, with regulatory guidelines to define and penalize deviations from T&D loss benchmarks. They recommended a trial run of the BMC, using idle capacity and permitting BPCs to procure part of their needs from renewable sources on payment of nominal UoSC, thereby generating revenue for SOLRs. Consumer security deposits already held by DISCOs could, in their view, be utilized to meet security cover obligations.
- 2.4.19 In response, MO clarified that imbalances are inherent to economic dispatch models and need not be penalized, as suggested, since they can be beneficial when priced at market rates. It stressed that SoLRs should not be held liable for imbalances caused by generation variations. Proposals to rename FPA/FCA or







alter QTR duration were deemed unnecessary, with current frameworks adequate to ensure uniform tariffs. MCC already embeds mechanisms for automatic settlement of benchmark losses, with penalties against network operators for excesses. Security of supply, it stressed, is guaranteed through firm capacity obligations. Suggestions to use consumer security deposits were rejected as legally impermissible. Recovery of prudent security costs via tariff, however, may be considered.

- 2.4.20 BOI commented that NEPRA may proceed as per policy / rules in vogue in the matter.
- 2.4.21 PPDB urged a reconsideration of the marginal price methodology prescribed in the MCC, suggesting that compensation based on the most expensive generating unit requires review. It pointed out that the FTR report failed to address congestion and overloaded areas, which are critical for proper scenario analysis. PPDB further cautioned that imbalances caused by system constraints and partial loading factors may give rise to disputes and complexities and therefore sought clear regulatory directions for handling such situations with emphasis on least-cost dispatch. It expressed concern over additional tariff impacts arising from inclusion of security cover, security guarantee fund, and extended peak hours, stressing that Punjab consumers would be disproportionately affected. Further, it requested representation in the Commercial Code Review Panel.
- 2.4.22 On the comments of PPDB, MO observed that while PPDB raised tariff concerns, overall market efficiency under CTBCM is expected to reduce costs. Security covers are minimal in cost, with returns credited back, and not required for DISCOs until bilateral contracts are signed. System peak hours affect only capacity obligations, not consumer tariffs. Punjab's representation in CCRP is assured through provincial entities.
- 2.4.23 PAEC while generally supporting the framework, endorsed the recommendation that firm capacity certification should rely on periodic dependable capacity tests rather than historical generation data, as being more reliable and practical. It further proposed that its representative be included in the Commercial Code Review Panel (CCRP) to safeguard its interests.
- 2.4.24 With regards to the representation in CCRP, it was pointed that legacy contracts are not code participants being protected from the market risk, therefore, inclusion in CCRP is not required.
- 2.4.25 SO commented that the default values specified in the MCC may be adopted for implementation of the BMC until the required parameters, such as reserve margin, efficient reserves, and Levelized Investment Cost of Reference Technology, are finalized. It further clarified that identification of critical hours is not feasible until







the market is operational and all participants are active, and therefore, the assumptions contained in the MCC should continue to apply in the interim.

- 2.4.26 In response, the MO concurred with the comments regarding the use of the default values until determined by SO. Regarding the critical hours, it was informed that the SO has provided data as per the provisions of the MCC, and the assumptions are valid as commented by the SO.
- 2.4.27 KATI emphasized that UoSC charges must be reduced to Rs. 8–10/kWh to ensure CTBCM's viability, objecting to the transfer of DISCO inefficiencies and extraordinary cross-subsidies onto industry. It called for strict verification of test-run action items with continuous monitoring, robust IT infrastructure with certified backups, consolidation of bank accounts, and standardized terminology aligned with international practice.
- 2.4.28 In response, MO agreed that excessive UoSC charges could hinder B2B transactions. It reiterated that cross-subsidy removal is a policy matter outside MO's remit. It confirmed completion of most action items, with remaining items near finalization. On IT, MO affirmed certified protocols and Enterprise Resource Planning (ERP) based transparency. Consolidation of bank accounts was justified as efficiency-driven without compromising oversight. Further, MCC nomenclature has been revised in line with international standards.
- 2.4.29 KPTMA expressed concern over tariff volatility for domestic consumers under CTBCM and sought safeguards. It further inquired about the integration of renewable energy, emissions reduction, and advanced technologies such as smart grids, blockchain, and advanced metering. Stressing cybersecurity, system resilience, and effective market surveillance, it also highlighted the need for strategies to attract investment in renewables and transmission, along with a clear long-term roadmap of milestones and benchmarks. KPTMA underscored the necessity of regulatory flexibility with transparent adjustments and structured stakeholder consultations.
- 2.4.30 In response, MO clarified that CTBCM initially applies to wholesale consumers above 1MW, with gradual expansion to retail markets as liquidity improves. Domestic consumers are not immediately impacted but expected to benefit long-term. Legacy contracts or PPAs will remain allocated to DISCOs, with future procurements bilaterally contracted to enhance accountability. CTBCM framework supports renewable integration, emissions reduction, and adoption of advanced technologies like smart grids and blockchain. MO responded that market integrity will be safeguarded by a Market Monitoring Unit. MO emphasized adherence to international best practices, robust cybersecurity, and structured capacity-building. CCRP governance ensures transparency, while the







evolution of the CTBCM will be marked by new products, trading schemes, and performance benchmarks.

### **3. Public Hearing**

- 3.1 The Authority, having considered the aforementioned comments, decided to conduct a public hearing in the matter and also framed the issues for the same. The hearing was convened on May 30, 2024, and thereafter reconvened on July 30, 2024, wherein the MO and other stakeholders participated and presented their respective viewpoints.
- 3.2 The succeeding paragraphs provide a comprehensive account of the issues deliberated during the public hearing, briefly incorporating the responses of the stakeholders, followed by the findings and decisions of the Authority.

### **4. Issues and Decisions:**

- 4.1 **Whether the twenty-four action items approved by the Authority in the Competitive Trading Bilateral Contract Market (CTBCM) test-run plan have been successfully completed by the Market Operator, System Operator and other entities or otherwise?**

4.1.1 MO submitted that all preconditions for operationalization of CTBCM had been completed by the relevant entities. The Market Management System (MMS) had been fully developed, rigorously tested, and operational since June 2022, producing monthly settlements without significant difficulties. It was submitted that MO had formed a committee to specify benchmarking parameters for the MMS and was coordinating with donor agencies to complete this activity by the end of 2024. Further to the said, MO stated that considerable progress has been made in implementing the merit order on a daily basis, even though it is not a precondition for Competitive Market Operations Date (CMOD), but necessary IT infrastructure has been developed and is undergoing testing.

4.1.2 Regarding the enrolment of market participants and service providers, MO received applications from all Ex-WAPDA DISCOs, with applications from KE and NGC still pending. Draft agreements had been submitted to NEPRA for review, and MO had requested the Authority to instruct KE and NGC to submit their enrolment applications. The last step involved signing Market Participation Agreements (MPAs) with existing SoLRs and Service Provider Agreements (SPAs) with network licensees. MO proposed that these entities be declared deemed Market Participants/Service Providers and be directed to sign the respective agreements within six months of the CMOD. Later on in August 2025, MO informed that its bank accounts i.e., security cover account and settlement guarantee cover account required for market settlements as mentioned in the MCC have been operationalized.







- 4.1.3 SO submitted that action items pertaining to it have been completed.
- 4.1.4 KE commented that completion of its action items is linked with the approval of CTBCM Integration Plan and will be completed in accordance with the same.
- 4.1.5 RE first submitted the successful completion of the twenty-four action items is essential for the effective implementation of the CTBCM. Given the completion of the FTR, a definitive date for the CMOD may be declared to avoid any unnecessary delays that could hamper the operationalization of competitive wholesale market.

**Findings and Decision of the Authority:**

- 4.1.6 The Authority has examined the FTR report, as well as subsequent submissions during the proceedings and is satisfied that the action items approved for the test run stand completed except those discussed in the succeeding paragraphs.
- 4.1.7 The two pending actions are (i). enrollment of market participants and service providers; (ii). benchmarking of MMS with those of international equivalents. In this regard, the Authority has accepted the request of MO for declaring the DISCOs, KE, and NGC as deemed Market Participants and Service Providers for their respective roles under CTBCM. These entities shall execute Market Participation Agreements and Service Provider Agreements with the MO within three (03) months from the date of issuance of this determination. Regarding benchmarking of MMS, the Authority allows a similar extension of three (03) months for the completion of this action item. Regarding action items linked with KE, the directions of the CTBCM Integration Plan approved vide determination of the Authority dated May 26, 2025, shall be followed in letter and spirit.
- 4.1.8 In addition to the foregoing, the Authority has noted that prospective market participants, such as industrial chambers, associations, bulk power consumers and generators, are not adequately aware of the CTBCM design and its features. Such knowledge gaps could hinder their meaningful participation in the market. The Authority therefore finds it imperative to direct that within one (01) month of CMOD and in coordination with NEPRA team, the ISMO shall initiate a structured capacity-building campaign through workshops, seminars and interactive sessions in major cities, with the initial phase to be completed within three (03) months. This campaign shall initially focus on generators, prospective competitive suppliers, BPCs, industrial associations and chambers of commerce, etc., covering eligibility requirements for market participants, types of contracts, security cover, trend of marginal prices, balancing mechanisms, firm capacity certification, open access charges recovery mechanism, captive and merchant generation. The MO shall submit periodic updates to the Authority on all actions and measures taken in pursuance of this direction.







- 4.1.9 The Authority further observes that transparency of information is a fundamental requirement for the efficient functioning of a competitive electricity market. Timely access to settlement statements, marginal prices, and related reports is essential for market participants to make informed decisions, assess market outcomes, and ensure accountability. The Authority hereby obligates ISMO to ensure the provision of complete, accurate, and publicly accessible market data, thereby upholding the principles of transparency, fairness, and informed participation. Accordingly, the ISMO shall, on the date of CMOD, publish on its website the results of the FTR, including settlement statements and marginal prices for the preceding two (02) years.
- 4.1.10 The Authority determines that the majority of action items have been completed, thereby warranting the declaration of CMOD. However, in terms of Strategic Directive 88 of the National Electricity Plan, the declaration of CMOD is contingent upon the determination of open access charges under Strategic Directive 87. Subsequently, the Federal Cabinet, vide its decision dated July 29, 2025, amended the Strategic Directive 87, and bifurcated the open access charges into two, namely grid charges and the stranded cost framework. Under the new amendment, the National Electricity Plan provides that the grid charges will be approved by the Authority, while the stranded cost framework will be issued by the Federal Government. Accordingly, the Authority decides that the CMOD shall be the later of (i) the date of determination of grid charges by the Authority; or (ii) the date of issuance of the Framework/Policy Guidelines by the Federal Government under National Electricity Plan.
- 4.2 Whether the IT infrastructure deployed by NTDC and MO for CTBCM transactions has been tested and certified as successfully implemented? Additionally, whether backup or alternative measures are available in case of system failure during market transactions, and whether the absence of SCADA will impact the successful implementation of the market?**
- 4.2.1 MO submitted that the basic purpose of the trial run was to rigorously test the IT infrastructure by conducting transactions on the same. The MO and the SO have been conducting all the transactions using these systems since June 2022 and have successfully processed billions of records to produce the settlements on monthly as well as annual basis. During the test run, these systems have been continuously improved in order to cater to the needs of the competitive market. Regarding the backup or alternative measures, it was reported that MO is following state of the art system security and data protection protocols and there are backup and restoration procedures in place in case of any system failure. Reportedly, the IT systems and protocols are duly certified under the relevant standards. The market settlements are based on the (i). metering data collected through the secured metering system (SMS) installed at Common Delivery Points (CDPs) by NGC;







(ii). System Operator Data Exchange Portal (SDXP); (iii). Marginal Price Application of the SO; and (iv). the MMS deployed by the MO. Further, the MO confirmed that all the aforementioned systems remained functional throughout the test run and have been tested successfully. Therefore, the absence of SCADA will not impact the successful implementation of the market.

- 4.2.2 SO submitted that it has successfully deployed its IT infrastructure along with software applications and allocated human resources for the CTBCM transition. The deployed infrastructure underwent rigorous testing during the test run period to ensure seamless functionality. Additionally, SO has established a Disaster Recovery (DR) site in Lahore, complemented by daily backup maintenance. To guarantee uninterrupted access to application data, SO maintains real-time data synchronization between the primary site in Islamabad and the secondary DR site in Lahore. All these measures adhere to the ISO standards, ensuring the highest level of reliability and security. Furthermore, SO has diligently integrated all the relevant requirements of the MCC into the SDXP including marginal price calculation. The SO further submitted that the entire development of the CTBCM design has been carried out, keeping in view the absence of SCADA. SDXP and MMS are fully capable of implementing CTBCM in its current form. Dispatch instructions and market related data communication such as availability declaration, startup, shutdown and ramp up/down instructions, calculation of marginal prices, data reporting, etc., shall continue through SDXP even after commissioning of the SCADA.
- 4.2.3 KE commented that for effective implementation of the CTBCM, it is important that the readiness and robustness of IT systems is fully tested prior to CMOD. KE stated that during the test run, Preliminary Settlement Statement (PSS) and Final Settlement Statement (FSS) issued by the MO only include data related to DISCOs and generators (IPPs, GENCOs and WAPDA hydel projects). However, for efficient roll-out of the market, settlement of energy and capacity of bilateral contracts of prospective market participants (generators and bulk power consumers) should be simulated and validated prior to CMOD.
- 4.2.4 RE First commented that since CPPA-G was granted the MO license on May 30, 2022, the integration of SCADA into the system should have been completed to support real-time dispatch and ensure transparent discovery of marginal prices as the investment had already been approved in 2013. The deployment and certification of IT infrastructure as well as implementation of SCADA are vital for the success of CTBCM should proceed without delay. However, this integration should not hinder the launch of CTBCM, which can be executed concurrently.







**Findings and Decision of the Authority:**

- 4.2.5 The Authority is satisfied with the submissions of the MO and the SO regarding readiness of their IT systems to support CTBCM implementation. They have also demonstrated the readiness of their systems during the proceedings of the FTR. Further, as reported, the IT systems incorporate advanced security, data protection, and backup mechanisms. The Authority observes that MMS has been tested for all market transactions wherein settlements for DISCOs were based on actual data, whereas dummy contracts were used for BPCs.
- 4.2.6 The Authority finds it important to note here that although SCADA deployment will enhance operational efficiency, its absence does not prevent the commencement of CTBCM. However, delays in SCADA are noted with concern, as it is critical for secure grid operations and market evolution, including ancillary services market. In this regard, ISMO is hereby directed to submit a comprehensive progress report on deployment of SCADA, covering its implementation status, bottlenecks, integration milestones, and measures for full functionality across generation, transmission, and distribution segments. The report shall demonstrate readiness for market evolution, including real-time spot markets and ancillary services market, and shall be submitted to the Authority by December 2025.
- 4.2.7 In addition, the Authority directs ISMO to ensure its IT systems remain fully updated, functional, and capable of supporting CTBCM operations at all times, with robust backup and disaster recovery mechanisms in place.
- 4.3 **Whether any delay in the implementation of central economic dispatch of the entire country will have any impact on the implementation of CTBCM?**
- 4.3.1 MO submitted that CTBCM can be implemented within the service territories of the DISCOs without requiring the inclusion of KE in the central economic dispatch. However, implementation across the entire country would yield the additional benefit of reducing overall generation costs, subject to the operational constraints between the NGC and KE systems.
- 4.3.2 SO submitted that in the absence of central economic dispatch, it shall calculate the marginal price of plants excluding those in the territory of KE. Whereas, supply of power to KE shall continue in tie-line mode as per the Interconnection Agreement (ICA) between KE and NGC.
- 4.3.3 KE commented that central economic dispatch, though linked with the fundamentals of the CTBCM design, is not dependent on its implementation and may therefore precede it.







- 4.3.4 RE First submitted that delay in implementing central economic dispatch across the country could impact effectiveness of the CTBCM. It stated that in terms of the NEPRA Act, a unified generation pool with a single marginal price governed by one system operator is mandatory. However, it should not delay CTBCM, and both processes should proceed in parallel. In this regard, integration of the system of KE with that of NGC should be ensured at the earliest.

**Findings and Decision of the Authority:**

- 4.3.5 The Authority vide determination dated May 26, 2025, approved the CTBCM Integration Plan submitted by KE. In the said determination, the Authority directed KE and the SO to finalize a Standard Operating Procedure (SOP) for integration of system operations of the KE. In this regard, KE and ISMO have reported that the central despatch shall be implemented upon CMOD, and the SOP is being finalized. In view of the foregoing, the Authority hereby directs ISMO and KE to ensure implementation of the centralized despatch as per its determination dated May 26, 2025.
- 4.4 **Whether the CTBCM transactions including settlements of energy and capacity of bilateral contracts for prospective market participants (generators and bulk power consumers) have been simulated during the test-run?**
- 4.4.1 MO submitted that the purpose of the trial run was to simulate the transactions, including settlements of energy and capacity, pertaining to bilateral contracts of market participants. In this regard, MO has undertaken the following two types of simulations with multiple scenarios:
- (a) Simulations on actual data: MO configured all the legacy systems in the MMS as per provision of the MCC. This configuration included mapping of all CDPs (more than 750) with respect to their location in the network and relation with the market participants and the specification of the contract types i.e. generation following design for generators, load following design with commercial allocation for DISCO and Power Procurement Agency Agreement (PPAA) for KE. The system has been producing market settlements since June 2022 and has processed millions of records successfully. MO has been publishing two settlement statements on monthly basis.
  - (b) Simulations on Hypothetical Data: MO has also tested the MMS with hypothetical scenarios in order to cater for the future CTBCM needs. In this regard, simulations have been performed for transactions between BPCs, competitive suppliers, traders and generators. Further, the role of small power producers has also been simulated as enrolled persons as per provisions of the MCC.







- 4.4.2 SO submitted that all the requisite data is being provided to the MO through SDXP as per the requirement of the MCC.
- 4.4.3 KE commented that considering the significance of IT systems for effective implementation of the CTBCM and bringing transparency and efficiency in the overall operations of the market, including deployment of SMS and market transactions, it is important that the readiness and robustness of IT systems are fully tested prior to CMOD.

**Findings and Decision of the Authority:**

- 4.4.4 The Authority has noted the confirmation from MO that hypothetical scenarios were simulated to test the systems for prospective transactions by BPCs. The Authority observes that as the market has not yet commenced, therefore, actual data pertaining to market transactions of BPCs was not available. In the circumstances, reliance on hypothetical data for testing is considered adequate. In addition, as reported by the MO, the systems have been tested for real-time operational data of DISCOs and legacy contracts. This combination of simulated and actual testing demonstrates that the IT systems are sufficiently capable of processing and settling prospective contracts under CTBCM, consistent with the analysis undertaken in Issue No. 4.2 above.
- 4.4.5 Nevertheless, the Authority hereby directs the MO to ensure that its IT systems remain fully operational, reliable, and capable of processing all categories of transactions under the CTBCM. The MO shall implement required upgrades and enhancements in a timely manner to guarantee uninterrupted, efficient, and transparent conduct of market operations.
- 4.5 Whether the planned mechanism to shift capacity invoices based on commercial allocation factors along with operationalization of BMC as per the provisions of the National Electricity Plan is justified? What are the bottlenecks of shifting capacity invoices from the existing mechanism to coincidental system demand-based mechanism immediately after CMOD?**
- 4.5.1 MO submitted that the proposals to operationalize the BMC and shift capacity invoices from the current practice to commercial allocation based mechanism is rooted in the National Electricity Plan, minutes from consultative sessions during the trial run, and the Agency Code. The National Electricity Plan provided that allocation factors will be based on the share of each DISCO/SoLR in the coincidental system peak, averaged over the last three years. Further, in terms of the National Electricity Plan, the Ministry of Energy (Power Division) shall determine the allocation factor of each DISCO. Till such determination is made, the mechanism incorporated in the MCC would be used for determination of commercial allocation factors. The MCC specified that initial allocation factors







would be based on the average of the last three years' capacity invoice data, reflecting the non-coincidental Maximum Demand Indicator (MDI) of the DISCOs in their role as SoLRs. Concerns had been raised by several DISCOs regarding the non-coincidental MDI mechanism due to its inherent flaws.

- 4.5.2 In addition, the MO submitted that during the consultations stakeholders were of the view that initial allocation factors based on historical capacity invoice data be used for planning purposes and energy imbalances. Further, a transition period should be provided for calculating allocation factors for capacity invoices by the SPA. Additionally, the draft Agency Code also included a transition period for the purposes of capacity invoices based on allocation factors. Accordingly, the MO submitted that a transition phase be considered for shift from the MDI mechanism to commercial allocation factors.
- 4.5.3 MO further proposed that the BMC should be implemented following the transition to commercial allocation factors based methodology for capacity invoices to DISCO(s), with strict observance of capacity obligations to prevent free riding by other market participants. MO also suggested that the shift from the existing mechanism to the coincidental peak-based mechanism could be made immediately after the CMOD subject to provision of necessary data by the MSP.
- 4.5.4 KE was of the view that its capacity charges will be billed on the basis of MDI as mentioned in the PPAA signed between KE and CPPA and the ICA signed between KE and NGC (Agreements). Further, as per KE's PPAA with CPPA-G, ICA with NGC and the approved MCC, for KE, the allocation factor shall be a fixed value, which may only be revised as per mutual agreement of the parties and the terms and conditions of these Agreements. In this regard, KE referred to Strategic Directive 45 of the National Electricity Plan, which stipulates that the power allocation for KE shall be in accordance with the quantum under contractual or other arrangements in place.

**Findings and Decision of the Authority:**

- 4.5.5 The Authority observes that historically, the shifting of capacity invoices to a coincidental system peak based mechanism was constrained due to the absence of reliable metering data at all CDPs. Since the commencement of the test run in June 2022, metering data of coincidental system peaks for the last three (03) years has been recorded and is available, with the sole exception of CDPs between PESCO and TESCO. This dataset is sufficient to enable immediate transition to coincident-peak based allocation factors following the CMOD.
- 4.5.6 The Authority further notes that commercial allocation factors under the MCC serve three distinct purposes, including settlement of energy imbalances in the BME, monitoring the compliance of SoLRs with their capacity obligations, and







invoicing of capacity charges to SOLRs by the SPA. The invoices for capacity based on commercial allocation factors have been addressed in detail in the Authority's determination pertaining to the grant of Special Purpose Agent registration to CPPA-G and approval of the Agency Code. The said code provides a transition mechanism from the CMOD, comprising an initial three (03) month trial period on the coincidental peak, followed by a nine (09) month commercial application period, after which the commercial allocation factors methodology will be implemented.

- 4.5.7 Moreover, the Authority does not find any merit in the proposal of the MO to delay implementation of the BMC, linking it with the transition to commercial allocation factors based mechanism. The availability of metering data for coincidental system peaks provides sufficient grounds for implementation of the BMC without delay. Accordingly, the Authority hereby directed the MO to implement the BMC as per the provisions of the MCC without any delay.
- 4.5.8 The Authority further finds that Strategic Directive 45 of the National Electricity Plan clearly vests responsibility for determining allocation factors in the Ministry of Energy (Power Division). Until such determination is issued, allocation factors shall continue to be calculated in accordance with the MCC. As an interim arrangement, the MO shall calculate allocation factors using coincident-peak data. However, this role is strictly temporary. Given the significant impact on DISCOs and direct implications for the BME and BMC, the MO shall, without delay, engage the ministry forthwith for the formal determination of allocation factors.
- 4.6 **Whether the proposal to shift to a new mechanism for calculating firm capacity certification based on an annual dependable capacity test instead of generation contribution in critical peak hours is justified? What were the challenges faced with the approved methodology and are they addressed in the proposed methodology?**
- 4.6.1 MO submitted that during the test run, it was observed that the availability of the thermal power plants encompasses several operational issues, especially related to the fuel availability. There are different provisions in different agreements related to the availability of the power plants when there is a fuel shortage, which is not in the control of the power plant operator. Therefore, after deliberations and to avoid any ambiguity, it is proposed that the firm capacity of the thermal generation plants should be based on the annual capacity tests being performed by the CPPA-G for the legacy plants. For future plants, the same test will be performed by the SO. MO further submitted that this approach may weaken the incentive of being available at the critical time; however, it is of the opinion that the respective agreements have certain provisions to ensure availability at the critical times when generation is needed in the system.







- 4.6.2 MO further reported that its international consultant has advocated in favour of the already approved methodology which is based on generation contribution in the critical hours based on the argument that a shift to Annual Dependable Capacity (ADC) test would significantly diminish the incentive of being available at the critical time. MO stated that it is submitting the report of the international consultant and the opinion of the SO, along with the recommendations of the FTR report, for an informed decision by the Authority. Regarding the challenges faced in the approved methodology, it was submitted that the data to calculate the firm capacity was available and provided by the SO and firm capacities were calculated accordingly. However, the only challenge was the ambiguity in considering the availability for certain generation plants with non-availability of the fuel. The revised methodology addresses this challenge since it is independent of any operational parameters.
- 4.6.3 SO submitted that firm capacity should be calculated on the basis of actual availability instead of the ADC test to encourage availability of generation capacity during the critical peak hours.
- 4.6.4 KE commented that within the FTR Report submitted by the MO, amendment has been proposed to change the mechanism of firm capacity determination for thermal based generation units from historical availability data to the annual / dependable capacity test. In this regard, the mechanism for annual / dependable capacity for the purpose of determination of firm capacity for KE's generation plants shall be as per KE's generation tariff approved by the Authority.
- 4.6.5 RE First submitted that the proposed shift to a new mechanism for calculating firm capacity certification based on an annual dependable capacity test instead of generation contribution during critical peak hours may unfairly disadvantage renewable energy generators. An alternative approach is needed in order to reflect the true capabilities of REs. For example, the California Independent System Operator employs an effective load carrying capability approach to evaluate REs, offering a more accurate assessment of their contribution to grid reliability.

**Findings and Decision of the Authority:**

- 4.6.6 The Authority observes that the mechanism in the existing MCC which is based on actual availability during system peak or maximum stress hours, ensures reliability of generation during critical periods. It also prevents any potential market manipulation. Accordingly, the Authority finds the proposal to revert to ADC test-based methodology untenable.
- 4.6.7 The Authority is of the considered view that calculation of firm capacity during peak hours will not alter payment obligations under existing Power Purchase Agreements (PPAs) or Energy Purchase Agreements (EPAs), which remain







governed by their contractual provisions. Firm capacity is a regulatory instrument to ensure dependable availability during critical demand hours and is not a substitute for contractual payment arrangements. For legacy contracts, where payment terms are fixed under executed PPAs, firm capacity shall be calculated under the MCC for planning and system security purposes only, without affecting payment obligations; however, parties may, by mutual agreement, adopt a critical-hours availability-linked payment mechanism.

- 4.6.8 The Authority further observes that for new bilateral contracts to be executed by DISCOs/SoLRs, payment provisions linked to availability during system peak hours should be considered during the development of security package documents.
- 4.6.9 In view of the foregoing, the Authority hereby decides that the firm capacity mechanism based on actual availability during system peak hours shall remain in force, and the proposal for an ADC test-based methodology is not approved. In addition, payments under legacy contracts shall continue strictly in accordance with executed PPA(s)/EPA(s), whereas firm capacity will be calculated for planning and system security purposes only. For new bilateral contracts, critical-hours availability-linked payment provisions should be considered for incorporation during development of the security package documents.
- 4.7 Whether the proposed changes in the formulae of Total Demand, Capacity Obligation, Firm Capacity and Ancillary Services etc. in approved Market Commercial Code are justified and have they been tested during the test run?**
- 4.7.1 MO submitted that all of the formulas approved in the MCC were duly tested in the MMS and most of these formulas were executed successfully without any issue, however, where some issues were identified, solutions were considered, and the revised formulas were tested again in the MMS to check for their suitability. Following are few examples of the modifications in the formulas:
- (a) Calculation of Total Demand: The earlier formula for calculation of Total Demand did not work because of the configuration of the metering points in the transmission network. It did not capture the flow from the 132 KV network towards 220 KV network through the meters installed on incoming/outgoing lines of power plants. Therefore, the formula was modified and tested successfully in the MMS.
  - (b) Capacity Obligation: Two modifications have been proposed in the formula for capacity obligations. One modification is in the formula to determine the capacity obligation to capture the impact of the distribution losses when a load is connected at the distribution level. Another modification is proposed regarding the obligation percentage in the 3<sup>rd</sup> and







4<sup>th</sup> year of verification. Instead of having a fixed percentage value, which created confusion among stakeholders, now the value is linked with the growth rate during the verification period.

- (c) Firm Capacity: The formula for firm capacity of thermal generation plants has been modified from the existing average of last three years actual availability during the system peak hours to dependable capacity multiplied by the forced outage allowance. A detailed rationale for this change has been provided in response to issue at para 4.6 above.
- (d) Ancillary Services: In this part, no modification has been suggested in the calculation of charges for ancillary service and must run generation, however, additional formulas are incorporated for allocation of these charges among different zones to ensure transparency and fair allocation.
- (e) Calculation of Unit-wise Generation and Back feed Energy: During the test run, it was observed that there are generation plants on which meters are not installed at each individual unit, but these are located in the outgoing lines which measure the combined output of the power plant. Therefore, formulas were devised to estimate the individual unit production from the combined output of the power plant.

4.7.2 The MO confirmed that all these revised and new formulas have been successfully tested in the MMS and address the issues encountered during the test run.

4.7.3 KE commented that with respect to the proposed changes in the formula of total demand, capacity obligation, firm capacity and ancillary services the following may be considered:

- (a) Total Demand: With reference to the proposed formula given in the revised MCC for the calculation of total demand, it is understood that the previous formula did not envisage certain power flows from distribution networks towards transmission networks due to embedded generators. In this regard, it is requested that detailed understanding be shared with all stakeholders regarding the reason behind the proposed revision and any expected impact that it may have on market participants, including the BME mechanism.
- (b) Capacity Obligation: With reference to the amendment proposed in the revised MCC regarding computation of capacity obligations for 3rd and 4th year based on CAGR, it was requested that clarity be provided on the period for which CAGR has to be calculated along with an illustration, for determination of Capacity Obligations for the 3rd and 4th year.
- (c) Firm Capacity: It has been proposed to change the mechanism of firm capacity determination for thermal based generation units from historical







availability data to the annual / dependable capacity and Forced Outage Rate of the plant. In this regard, it was submitted that the mechanism for annual / dependable capacity for the purpose of determination of firm capacity for KE generation plants shall be as per KE's generation tariff. Further, it is requested that any change in the mechanism of firm capacity determination should be made after proper consultation and through CCRP forum as mentioned in the revised MCC.

- (d) Ancillary Services: With reference to the formula given in the revised MCC for calculation of compensation for provision of ancillary services and Transmission & Reliability Must Run Generation, it is submitted that a holistic evaluation and an impact analysis of change in the formula, on market participants, be shared with all the stakeholders along with illustrative examples, for review and consultation. Further, considering the possible implications for market participants including the regulated consumers, KE requested that a detailed impact assessment of the proposed changes in the formulae along with possible implications be carried out and shared with all relevant stakeholders for further consultation and finalization prior to its approval by the Authority.

- 4.7.4 Further, considering the possible implications for market participants including the regulated consumers, KE requested that a detailed impact assessment of the proposed changes in the formulae along with possible implications be carried out and shared with all relevant stakeholders for further consultation and finalization prior to its approval by the Authority.

**Findings and Decision of the Authority:**

- 4.7.5 The Authority has examined the proposed revisions by the MO in formulas and methodologies in the MCC based on the FTR. With respect to the formula for total demand, the Authority observes that the earlier formula failed to capture flows from 132 kV to 220 kV network, producing errors. The revised formula, calculating total demand by subtracting transmission losses from total generation, has been successfully tested in the MMS and is accordingly approved.
- 4.7.6 Regarding capacity obligations, the Authority concurs with the revision to account for distribution losses when load or exports are connected at the distribution level, as this reflects actual system conditions. However, the proposal to replace Year 3 and Year 4 obligations of 80% and 60% with 1-CAGR is not approved. The Authority holds that capacity obligations are intended to secure 100% contracting of forecasted demand at year 0, with prudent percentages of 80% and 60% reserved for years 4 and 5. The balance capacity required for years 4 and 5 can be contracted progressively during the intervening three-year period, ensuring adequacy of supply while maintaining prudence and avoiding distortions







in contracting obligations. Indexing the same to CAGR risks distortion, as a positive CAGR would reduce obligations below prudent levels while a negative CAGR would inflate them unnecessarily. In the absence of any substantive justification, the percentages earlier approved in the MCC shall remain operative, and no revision is being made as there is no demonstrable evidence of need.

- 4.7.7 The Authority notes that the proposed change in methodology for calculating firm capacity of generators has already been addressed under issue at para 4.6 above and requires no further discussion.
- 4.7.8 On ancillary services, the Authority observes that while the MCC contained descriptive provisions for inter-zonal adjustments, detailed formulas were necessary to allocate charges where energy is exchanged between zones. The additional formulas developed by the MO, tested without error during the FTR, ensure fair allocation of must-run and ancillary service charges within each zone and to exports, prorated by utilization. These are accordingly approved.
- 4.7.9 The Authority further observes that unit-level generation calculation is essential for accurate settlement of ancillary services, as unit costs may vary within a plant. The MO has reported that, for some plants, metering exists only at the outgoing line level, therefore, it developed formulas to estimate unit-wise output based on synchronization status and declared availability. The same were successfully tested during the FTR. The Authority approves their adoption, noting that they ensure fair and accurate unit-wise compensation.
- 4.8 Whether the proposal to defer compensation for ancillary services until the identification of congested zones by the System Operator is justified? Should transitory provisions for compensation of ancillary services for existing zones i.e. NTDC and K.E. be retained in the Market Commercial Code until the identification of congested zones by the System Operator?**
- 4.8.1 MO submitted that, as per provisions of the MCC, the compensation for ancillary services are charged to the market participants based on their location in a congested zone. However, if no congested zone is identified, the calculations cannot be performed. The purpose of this modification was to expedite the process for the determination of the congested zones; however, the Authority may allow congested zones on a transitory basis as the MMS already caters for this aspect.
- 4.8.2 SO submitted that it supports the zone formulation as per the definition of congested zones in the MCC. As such, there are only two independent networks in the existing system, of NGC and KE, and the provision of compensation for ancillary services for these zones should be retained. SO further submitted that it has already provided all details with regard congested areas within the aforementioned zones to the Authority through the Transmission System







Expansion Plan (TSEP) and Annual System Reliability and Integrity Report (ASRAIR).

- 4.8.3 KE commented that as per the Clause 6.2.1.6 of the revised MCC submitted by the MO for approval of the Authority, the provision for compensation of *must-run* generation (transmission must run and reliability must run generation) and ancillary services is proposed to be deferred till the time the SO identifies the congested areas / zones and the same is approved by Authority. In this regard, KE requested that till such a time, the current mechanism should be followed, where the compensation for ancillary services is made part of the national pool price, considering the possible commercial implication it carries for the regulated consumers as well. However, it is recommended that such compensation be identified as a separate component in the national pool pricing. Here, it is also important to highlight that during the stakeholders' hearing held on April 25, 2024, regarding the approval of the Agency Code, certain concerns were raised by the Special Purpose Agency and the SO regarding the transitory provisions for compensation of ancillary services and *must-run* generation. Therefore, it is important that the mechanism is thoroughly firm up and finalized after consultation with all relevant stakeholders before the opening up of the market.

**Findings and Decision of the Authority:**

- 4.8.4 The Authority finds that ancillary services are indispensable for ensuring system reliability and security; hence their timely compensation should not be deferred. The Authority further notes that identification of congested zones serves the essential purpose of ascertaining the zones liable to pay compensation for ancillary services. Accordingly, the Authority hereby decides that as a transitional measure, KE and NGC systems shall be deemed congested zones as historically been the case. This arrangement, however, is temporary and shall stand replaced once the SO, in accordance with the MCC, completes the identification of congested zones and notifies the same within three (03) months of this determination.
- 4.9 **Whether the proposed labels in the Market Commercial Code to tag generators operated due to different system operation considerations are justified? And what is impact of the same on the marginal price determination as well as market settlements?**
- 4.9.1 MO submitted that to determine the system marginal price and calculate compensation for ancillary services transparently and objectively; different labels were proposed to capture different operating conditions of the power plants. The approved commercial code for the test run included 10 labels to capture all of the conditions; however, during the trial run, the need for certain additional labels was identified to capture the conditions with more clarity and transparency. So as







a result, four additional labels (i.e. Voltage Support, Fuel Deficiency Constraint, Test Run, Ramping) were added to the methodology to capture different conditions under different labels. Regarding the impact of these labels on the determination of the system marginal price, it is submitted that these labels ensure that the system marginal price is determined based on most accurate and transparent data, reflecting the actual system conditions, which is accurately captured by the SO under these labels. This will also ensure the proper accounting of the compensation for ancillary services.

- 4.9.2 SO commented that the proposed labels are in line with the Grid Code, MCC and the operational realities of the system. These tags have been deliberated thoroughly by SO, MO and NEPRA. They have been designed so that generators being operated due to constraints are excluded from marginal price calculation. These generators become part of ancillary services/must run and are socialized accordingly. The marginal price calculation is a continuously improving methodology and would be refined over time based on market experience and feedback from the stakeholders. Tagging generators on hourly basis would make system operation and compensation of ancillary services more transparent.
- 4.9.3 KE commented that clarity be provided regarding the impact of the proposed labelling of the generators due to system operations on the marginal price determination. Further, clarity is also requested on consideration of only Voltage Support as a separate label from all the ancillary services according to the definition of Grid Code and also regarding different operational scenarios where a generator can be tagged as Operational Constraints.

**Findings and Decision of the Authority:**

- 4.9.4 The Authority is of the considered view that scheduling and dispatch of generators must be conducted in an auditable, transparent, and objective manner. Since dispatch decisions directly affect hourly marginal prices, the SCED must be implemented uniformly and without undue discretion across the country, including the KE region. Historically, SCED has been carried out manually, lacking software integration. The independent consultant engaged by the Authority has also pointed out that markets in North and Latin America have already transitioned to software-based SCED. Hence, the SO must follow this path to guarantee real-time monitoring, dispatch optimization, and auditability of system operations.
- 4.9.5 The Authority finds that a structured, software-based SCED integrated with SCADA is a key requisite for enhancing dispatch efficiency, reducing uncertainty in price determination, and fostering a competitive environment. This transition is necessary for establishing clear and predictable market conditions, thereby strengthening investor confidence and long-term stability of the market.







- 4.9.6 Therefore, the Authority is of the considered view that in principle marginal prices should reflect the cost of the most expensive fully or partially loaded generator, with minimal constraints. However, in real-time operations, system constraints influence economic dispatch, thus resulting in SCED. Under the approved CTBCM design, marginal price calculations exclude generators dispatched solely to meet system constraints, which is aligned with established international best practices.
- 4.9.7 International experience also shows that while constraint-based dispatch may be excluded from marginal pricing, excessive exclusions distort price signals and burden demand with the costs of must-run or out-of-merit generation. Marginal prices must therefore reflect real sector conditions, including operational and fuel-related constraints, ensuring that price signals remain efficient and fair.
- 4.9.8 With respect to the FTR proposal to apply additional operational labels to exclude certain generators from marginal price calculations, the Authority holds that legacy take-or-pay fuel arrangements may be excluded where risk lies with the purchaser, as already contractually agreed. In such cases, the resulting costs shall rest with the counterparties to those arrangements, i.e. DISCOs and KE, and not be socialized across all market participants. However, where post-CMOD agreements create new must-purchase obligations, the costs of such constraints shall be borne by the generator responsible. Generators with fuel contracts entered on a take-or-pay basis shall carry this risk, and it shall not be recognized as a system constraint.
- 4.9.9 Further, the Authority hereby directs the SO to separately record, evaluate, calculate, report, and publish the costs of forced generation due to system constraints/congestion. This data will provide critical input to transmission planning and development under Integrated System Plan (ISP).
- 4.9.10 Furthermore, the Authority accepts the use of operational labels as a temporary measure for the calculation of marginal prices. However, tags are not to be institutionalized. The ISMO is hereby directed to review these labels annually and propose amendments for their progressive removal through corrective measures under ISP. Further, the ISMO shall ensure implementation SCED integrated with SCADA's EMS and GMS control and optimization, ensuring auditable, transparent and dispatch.







**4.10 Whether transmission and distribution constraints will have any impact on the CTBCM transactions, especially on the bilateral contracts between bulk power consumers and generators/suppliers? What measures have been put in place by NTDC and MO in this regard?**

4.10.1 MO submitted that the transmission and distribution system is the basic infrastructure to be used by the parties engaged in bilateral transactions. Any issues in this network will definitely have an impact on these parties. Further, it is important to highlight here that the issues of the transmission and distribution network do not cause any hindrance in the settlements being performed by the MO. However, it will definitely have implications for the efficiency and liquidity in CTBCM. MO further submitted that it does not have any stake in the transmission or distribution business and cannot legally obligate any transmission or distribution licensee to undertake any measures in this regard.

4.10.2 SO stated that transmission constraints have been acknowledged under MCC, and operational labels of transmission must run, voltage must run, reliability must run, must stop, etc., have been introduced to address the same. These plants are part of ancillary services/must run. It is worth mentioning that must-stop plants, i.e. generators whose power cannot be evacuated due to transmission bottlenecks, will not be compensated. A detailed procedure has been provided in Grid Code for connection of new grid users to the national grid. Each grid user will carry out due diligence for securing most feasible connection point in the Grid. Transmission network service providers (NGC/PGC/DISCO) shall issue offer to connect after necessary transmission studies and approval of the SO. Transmission network operators (TNO) shall sign a Connection Agreement with grid users that should cover network risks such as tripping, SAIFI, SAIDI, and constraints. SO is obligated to highlight system constraints in the form of the ASRAIR and TSEP on regular basis, which will provide clear signals to market participants. However, as also highlighted during the public hearing, the procedure for compliance monitoring of TNOs with respect to power evacuation arrangements should be further strengthened to ensure the timely completion of transmission projects.

4.10.3 KE commented that the CTBCM design envisages implementation of SCED by the SO, i.e. a single country-wide central economic dispatch which will be subject to network security constraints and dispatch commitments under respective fuel supply contracts. Under SCED, the SO will issue dispatch instructions to generators after considering transmission and distribution network constraints, as a result of which, a possible consequence could be dispatching an expensive generator instead of available cheaper generator, which can subsequently have an impact on imbalances, system marginal price, etc.







4.10.4 RE First submitted that transmission and distribution constraints can significantly impact CTBCM transactions, particularly between bulk power consumers and generators/suppliers. These constraints can result in directives like must-stop for generators, leading to lost revenue and skewed marginal prices. TSEP should be prioritized and executed swiftly to alleviate these constraints and prevent curtailment issues, including those related to wind energy. In Brazil, transmission congestion issues have led to similar challenges in its power markets. To address this, the country has invested heavily in expanding and modernizing its transmission network to support the integration of renewable energy.

**Findings and Decision of the Authority:**

4.10.5 The Authority is mindful of the fact that transmission and distribution constraints are a critical factor influencing the effective functioning of the CTBCM. Such constraints directly affect the provision of open access, which is fundamental to ensuring a level playing field in the market. Where open access is delayed and suppliers face curtailment or non-dispatch of their generators, market participation is undermined and suppliers may be compelled to procure power at marginal prices to meet contractual commitments, exposing them to business risks and financial losses.

4.10.6 The Authority further observes that transmission and distribution constraints are an inherent characteristic of power systems worldwide. These challenges are to be addressed through timely and systematic augmentation of the network rather than by deferring or impeding market reforms. It is a matter of record that the Authority has consistently approved substantial investments and directed network licensees to prioritize the removal of such bottlenecks under their approved investment plans. The Authority reiterates that while constraints may give rise to operational risks, they cannot, under any circumstance, serve as justification for postponing the implementation of CTBCM.

4.10.7 In view of the foregoing, the Authority hereby decides that transmission and distribution constraints shall not be treated as a ground to delay or impede the implementation of CTBCM. All network licensees are hereby directed to take proactive measures to minimize these risks, including but not limited to the timely execution of projects approved under their respective investment plans; the development and implementation of a forward-looking TSEP; and strict compliance with performance standards duly specified by the Authority.







**4.11 Whether the proposal to reduce the number of separate bank accounts for Market Operator functions and proposed changes in the payment system is justified? Has the Market Operator ensured that transparency in transactions is not compromised due to the proposed changes?**

4.11.1 MO submitted that the approved MCC for test run included the following six bank accounts: (i). MO Settlement Account for Monthly Settlement: This was a clearing account for monthly settlement (BME). Security cover funds for monthly settlements were supposed to be received from /paid to the market participants through this account. (ii). MO Settlement Account for Yearly Settlement: This was a clearing account for yearly settlement (BMC). Advance payments were supposed to be received from/paid to the market participants through this account. (iii). MO Credit Cover Account for Monthly Settlement: Security covers from market participants were parked in this account. (iv). MO Credit Cover Account for Yearly Settlement: Advance payments against yearly settlement were parked in this account. (v). MO SGF Account: Settlement Guarantee cover was parked in this account. (vi). MO Miscellaneous Account: Interest and penalties were parked in this account. Under the previous payment mechanism, accounts at serial no (i) and (ii) above were to be used by market participants and MO for making/receiving payments. Accounts at sr. no. (iii) to (vi) would be used as parking accounts and funds would be transferred to/from accounts at serial no (i) and (ii). The original intent was to keep reconciliation simpler through multiple accounts. However, as an Enterprise Resource Planning system (ERP) has been deployed, reconciliation will be automated. Furthermore, transfers between bank accounts may also cause delay at bank's end and the settlement may not be completed on time on the settlement day.

4.11.2 MO further submitted that in order to reduce the complexity of transfers between banks and avoid delays, a new mechanism with only two bank accounts has been proposed as follows: (i). MO Security Cover Account: Funds received from market participants against Security Cover (monthly settlement), Advance payment (yearly settlement), interest, and penalties as well. This account will also be used by the MO to pay Market participants for monthly and yearly settlement. (ii). MO Settlement Guarantee Cover Account: Funds will be received from market participants against settlement guarantee cover in this account. If required, funds will be transferred to security cover account to bridge the gap for settlement. This mechanism will reduce the processing time at the bank's end and settlement will be completed on clearing day. All reconciliations will be performed in the ERP.







### **Findings and Decision of the Authority:**

- 4.11.3 The Authority finds merit in the proposal to reduce the number of accounts from six to two. With the implementation of the ERP system, reconciliations are now automated, eliminating the need for maintaining multiple accounts. Consolidation into two accounts, namely, the Security Cover Account and the Settlement Guarantee Cover Account, will streamline the settlement process, reduce unnecessary inter-account transfers, minimize delays associated with banking procedures, thereby enhancing overall market efficiency.
- 4.11.4 At the same time, the Authority emphasizes that efficiency cannot come at the cost of transparency. While the ERP system inherently provides an auditable trail of transactions, additional safeguards are essential to preserve market confidence. The MO must therefore establish a robust reporting framework, ensuring that market participants have access to regular and detailed reports, clear communication on the allocation and movement of funds, and readily accessible documentation that enables verification of transactions with clarity.
- 4.11.5 In light of the foregoing, the Authority approves the consolidation of accounts as proposed and directs the MO to ensure that the management of these accounts remains fully transparent, auditable, and subject to regular disclosure.
- 4.12 **Whether the rationale behind the nomenclature changes, including the redefinition of various terms and renaming of specific terms in the Market Commercial Code is justified?**
- 4.12.1 MO submitted that there were three changes related to billing and settlement terminology: (i). Credit Cover was changed to Security Cover, (ii). Credit Cover for Yearly Settlement was changed to Advance Instalment, (iii). Settlement Guarantee Fund was changed to Settlement Guarantee Cover. For the term Security Cover, it was explained that for monthly settlement, an estimate of the imbalance would be calculated, and payment would be requested in advance. Once the monthly imbalance was calculated, the security cover would be used for settlement and then replenished. The term credit was replaced with security because, in CTBCM, the MO would already have advanced funds, unlike the typical use of credit, where services are availed before payment. The term Advance Instalment was introduced for yearly settlement because the BMC would be calculated at the end of the year, divided into six equal instalments, and paid in advance by the market participant. Since these instalments would not be replenished like the monthly security cover, the term Advance Instalment was proposed to distinguish it. Additionally, the term Settlement Guarantee Cover replaced Settlement Guarantee Fund to avoid legal implications under the ICT Trust Act 2020, which would require the MO to register as a Trust entity, with trustees (market participants) controlling the investment and disbursement of





funds. To prevent confusion and legal complications, the term fund was replaced with cover. Lastly, the term lost opportunity cost was replaced with reduced generation cost to avoid the negative connotations associated with opportunity cost.

- 4.12.2 RE First commented that the current MCC mandates cash-based guarantees for market participants, which is increasingly seen as an outdated approach globally. Modern energy markets have shifted towards more flexible and efficient financial instruments, such as insurance-based guarantees, credit cover lines, and other banking instruments. These alternatives reduce the liquidity burden on market participants and provide equivalent or superior security. RE First requested to consider it in the interest of facilitating market participants, in line with international practices.

**Findings and Decision of the Authority:**

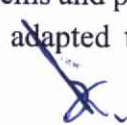
- 4.12.3 The Authority finds that the proposed revisions to billing and settlement terminology are appropriate. The shift from *Credit Cover* to *Security Cover* accurately reflects the pre-funded nature of settlements. Regarding the term, *Advance Instalment*, as explained by MO, the BMC is calculated annually, divided into six instalments, and paid upfront without replenishment. This structure is distinct from the revolving monthly security cover and therefore requires a separate nomenclature. The replacement of *Settlement Guarantee Fund* with *Settlement Guarantee Cover* avoids legal complications. Likewise, the substitution of *Lost Opportunity Cost* with *Reduced Generation Cost* ensures that terminology corresponds to the underlying operational realities rather than presumptions. Collectively, these adjustments eliminate ambiguity, enhance legal certainty, and strengthen the integrity of the market framework. Therefore, the Authority approves the proposed terminology changes.



- 4.12.4 The Authority further observes that while cash remains the most secure form of cover, exclusive reliance on cash may create liquidity pressures, particularly for new entrants and smaller suppliers. Therefore, the Authority has decided that the Security Covers, Settlement Guarantee Cover and Advance Instalment shall, as default, be in the form of cash. However, if mutually agreed between the MO and the Market Participant, other financial instruments may also be adopted as a mode of security.

**4.13 Whether Renewable Energy power plants that are not capable of providing ancillary services be allowed to participate in the CTBCM as merchant power plants?**

- 4.13.1 MO submitted that at the start of the market, the systems and procedures are at an initial stage, and the market players are not fully adapted to the competitive







environment. Then, in such a case, allowing Renewable Energy (RE) plants that are not capable of providing ancillary services to participate in the CTBCM as merchant plants would pose several risks. On one side, the RE developers will push for greater installation considering the high system marginal prices in the short term, while on the other hand, some people may not understand the concept of inframarginal revenue and may question it. Without proper assessment of the system condition in the long run, the RE developers may face challenges in the future when the system marginal price collapses due to a greater influx of renewables. Therefore, as a precaution, it is recommended that RE plants that are not capable of providing ancillary services should not be allowed to enter the market as merchant power plants, but they shall enter the market through bilateral contracts in order to provide some stability in the market. Later on, when the market matures, this condition should be reassessed.

- 4.13.2 SO submitted that induction of a large quantum of high intermittency VRE generators in the system is a critical matter due to lack of firm capacity, operational constraints, and dispatchability issues. This is evident from the change in system load patterns subsequent to extensive solarization. That is why safeguards such as firm capacity certificates and BMC have been placed in the CTBCM design. At present, the Grid Code does not obligate any RE plant to provide bidirectional frequency reserve (through battery storage) or contributing to AC system stability. Furthermore, it will be highly challenging for the SO to centrally optimize and manage the numerous small sized energy storage units at individual RE plants, each with different technical parameters. The dispatch decision of SO regarding charging/discharging of the battery systems would have direct financial impact on the merchant RE plant. In case the RE plant is connected with the distribution network, it shall not be subject to the Grid Code. Moreover, Battery Energy Storage Systems (BESS) provide solutions only for intra-day intermittent. Inter-day variations of RE availability shall be managed through unit startups/shutdowns, which poses additional operational challenges. The additional reserve requirements may significantly increase the number of expensive fast-ramping units committed in the system and affect least-cost dispatch, while substantially increasing part load adjustments. Globally, the said issue is managed through a dedicated ancillary services market to ensure cost effectiveness and system reliability. In light of the above, it is proposed that a cross-functional team should be formed to thoroughly analyze the issue in terms of technical and financial impact and provide suggestions for the smooth inclusion of merchant RE plants. This will also include amendment of ancillary service obligations for REs in the Grid Code with respect to Connection Code, Operation Code and Scheduling & Dispatch Code, through the Grid Code Review Panel (GCRP).







4.13.3 KE commented that the RE plants operating (without energy storage units) are not capable of providing ancillary services due to their intermittent nature, and therefore, they cannot participate as merchant power plants. Moreover, under the Grid Code, it is mentioned that the provision of ancillary services (except Black Start service) is mandatory for all generating units as per the requirements of the SO. Further, allowing RE plants to participate as merchant power plants can provide them with arbitrage opportunities, enabling such power plants to make excessive profits as well as would result in accelerated addition of renewable energy capacity in the system, which subsequently may adversely impact renewable capacity addition/optimization for the regulated consumers via competitive bidding process and hence if renewables power plants that are not capable of providing ancillary services are allowed to participate as merchant power plants, they may benefit at the cost of regulated consumers.

4.13.4 RE first commented that reflects a lack of understanding on the part of the SO. It is a blatant misconception that RE power plants, such as wind and solar, cannot provide ancillary services. Numerous studies and practical implementations globally have demonstrated that these resources can indeed support grid reliability and stability. Some of these have been presented below, along with relevant references:

- (a) Frequency Regulation: Wind turbines are capable of adjusting their power output to contribute to frequency regulation. For instance, wind farms in Denmark and the UK have successfully provided this service, supporting grid stability. Solar inverters can also respond to frequency deviations, as seen in California, where utility scale solar PV plants participate in the ancillary services market.
- (b) Voltage Support: Both wind and solar plants can provide reactive power to maintain voltage levels. The use of advanced power electronics, such as STATCOMs, has enabled wind farms in Germany and Spain to deliver voltage support. Solar PV systems in regions like Queensland, Australia, have also been integrated with reactive power capabilities to assist in voltage regulation.
- (c) Spinning Reserve: The rapid response capability of wind and solar, particularly when coupled with energy storage systems, allows these resources to serve as spinning reserves. In Texas, the ERCOT grid has integrated wind and solar with battery storage to provide such services.
- (d) Ramp Rate Management: Both wind and solar can manage ramp rates through advanced forecasting and control systems. In Hawaii, solar PV plants have implemented ramp rate control measures to prevent sudden fluctuations in power output.







- (e) **Grid Stabilization and Energy Storage:** The combination of renewable generation with energy storage enhances grid stabilization. For instance, the Hornsdale Power Reserve in South Australia, which includes a large battery system paired with wind energy, provides frequency control and other grid services.

4.13.5 In light of the above demonstrated capabilities of RE sources to provide ancillary services, RE First supported allowing RE generators as merchant power plants in the CTBCM regime. This participation will not only enhance grid stability but also support the country's transition towards a sustainable energy future. Moreover, with the right market mechanisms and technological integration, renewables can effectively compete with other technologies and go a long way in reducing electricity prices for residential, commercial, and industrial consumers alike.

**Findings and Decision of the Authority:**

- 4.13.6 The Authority, having examined the record of proceedings, stakeholder submissions, and the policy framework set forth under the NEPRA Act, as amended, and the National Electricity Policy, 2021, observes that the question of permitting RE plants to participate as merchant generators in the CTBCM merits careful consideration. The Authority notes that the NEPRA Act expressly envisages the development of renewable electricity markets in line with Pakistan's international commitments and climate obligations, thereby reinforcing the rationale for enabling merchant participation of RE plants.
- 4.13.7 The Authority finds that allowing RE plants to participate as merchant generators is also in line with international precedents. As highlighted by international consultants engaged by the Authority, the global experience already demonstrates that with enabling technologies, battery storage, advanced inverters, and reactive power capabilities, renewable generators can not only supply energy but also provide ancillary services, including frequency regulation, voltage support, and ramp-rate management. These are no longer emerging concepts but standard features in modern power markets.
- 4.13.8 At the same time, the Authority is mindful of the systemic risks posed by unregulated proliferation of merchant RE plants, particularly at the distribution level where plants are price-takers and not subject to SCED principles. Without prior technical assessment, such proliferation may give rise to congestion, reliability concerns, and inequitable treatment of market participants. The Authority therefore holds that the participation of RE plants as merchant generators, regardless of their point of interconnection, shall be subject to technical studies carried out by the System Operator under the Grid Code and Distribution Code.







- 4.13.9 The Authority further notes that merchant RE plants face the risk of curtailment under system constraints. To mitigate such risks and improve transparency in system operations, the SO is hereby directed to publish annually the available quantum of interconnection capacity and the network nodes where RE merchant generation can be accommodated/integrated. Moreover, to avoid discriminatory treatment of RE plants connected at the same node, the SO shall develop a transparent and competitive framework for allocation of dispatch priority.
- 4.13.10 In light of the foregoing, the Authority decides that renewable energy plants shall be permitted to participate as merchant generators in the CTBCM, subject to compliance with the applicable technical and commercial requirements. The ISMO shall establish mechanisms for its effective integration, including facilitation of ancillary services through enabling technologies. All technical studies for merchant RE integration shall be undertaken by the SO in accordance with the Grid Code and Distribution Code. The Authority further directs the SO to publish annually the available interconnection capacity and nodes for merchant generation, and to put in place a transparent and competitive framework for allocating dispatch priority among RE plants at the same node. In addition, the Authority hereby directs the SO to consider and propose required amendments to the Grid Code for ensuring reliable, stable and effective integration of RE merchant generators.
- 4.13.11 The Authority is of the considered view that with the aforementioned safeguards, the benefits of allowing participation of RE generators as merchants i.e. enhanced competition, cost efficiency and sustainability, decisively outweigh any perceived impact, ensuring a stable, equitable, and forward-looking electricity market.
- 4.14 Whether the provisions added in the proposed Market Commercial Code related to captive generation justified? Should captive generators register as market participants for the purpose of wheeling electric power for self-use?**
- 4.14.1 MO submitted that no specific provisions related to the Captive Generation Plants (CGPs) have been added to the commercial code, except for some explanations in the introductory part of the code. It was submitted that for availing open access, i.e. wheeling electricity either for self-use or selling to third parties, the captive generator will be subject to the same terms and conditions as any other generation plant. This means that it will be subject to the same requirements for becoming a Market Participant, even if it is availing open access for wheeling of electric power for self-use. Without registration as Market Participant, the imbalances of such a captive power plant cannot be settled in the Market.
- 4.14.2 SO submitted that CGPs, by definition, should include only those plants where the generation facility is within the premises of the substation and are not using







the network for wheeling. In case a CGP is wheeling power, it should be treated as a Market Participant.

- 4.14.3 KE commented that as per the approved CTBCM detailed design, the integration of CGPs into CTBCM was not approved, and it was decided that the Authority will address the issue through appropriate regulations/mechanism during the implementation phase of the CTBCM. However, KE understands that the wheeling of power from CGPs, even for self-consumption, shall be treated in a similar manner as other market participants, as the said plants shall be subject to central dispatch, settlement of imbalances, compliance with capacity obligation, and relevant provisions of the approved Grid Code and MCC, etc. Accordingly, CGPs will be required to register as market participants, as provided for in the revised MCC submitted by the MO for approval of the Authority.

**Findings and Decision of the Authority:**

- 4.14.4 The Authority recalls its earlier determination dated November 12, 2020, wherein the proposal of the CPPA-G in the draft CTBCM Detailed Design relating to captive generation was not approved, with the explicit decision that the matter would be addressed through an appropriate mechanism during the implementation phase of the CTBCM. Having now gained insights from the implementation process, the Authority considers it both timely and necessary to incorporate a structured framework for CGPs within the MCC. Such a framework is essential to enable captive consumers to avail open access for carrying electricity from their generating facilities to the point of consumption, while preserving market integrity, reliability of the system, and the principle of non-discriminatory access.
- 4.14.5 The Authority further observes that captive generation holds a distinct position in Pakistan's power sector. On one hand, CGPs have historically supplemented industrial and commercial loads, particularly in times of power shortages or unreliable supply from grid, thereby enhancing supply security. On the other hand, differential treatment of CGPs risks undermining the level playing field in the competitive market.
- 4.14.6 In light of the foregoing, the Authority observes that Section 14C of the NEPRA Act expressly provides that captive generation may avail open access for self-use yet mandates that supply of electricity from a captive generating plant through the grid *shall be regulated in the same manner as the generating facility of a generating company*. Accordingly, the Authority finds that where a captive plant performs the functional role of a generator by injecting power into the grid (notwithstanding that its ultimate beneficiary is its own captive consumer), it must carry the same technical, commercial and other obligations as any other generating facility.







- 4.14.7 The Authority is of the view that this principle requires two complementary strands of parity. First, on the generation side, a CGP that supplies energy into the network shall be treated as a generating facility under the Grid Code and Distribution Code. Second, on the consumption side, where the captive user draws that energy for its own use, the CGP/BPC arrangement shall be treated as equivalent to a supply to a Bulk Power Consumer under the MCC i.e., subject to the imbalance settlement, security cover, and capacity obligation etc., provisions that apply to BPCs availing open access.
- 4.14.8 The Authority further finds that this dual parity, as a generator under the Grid/Distribution Code and as a BPC under the MCC, is not only consistent with the legislative intent in the NEPRA Act but also necessary to avoid regulatory gaps, prevent differential treatment, and safeguard the principles of open access. By ensuring parity of obligations on both the generation and consumption sides, the framework enables captive generation to participate in the market without undermining system reliability or distorting competition.
- 4.14.9 Accordingly, the Authority decides that CGPs, when wheeling electricity through the grid, shall be regulated in the same manner as generation facilities under the applicable codes, whereas, the captive consumers of such plants, when receiving electric power through open access, shall be treated at par with BPCs under the MCC and other Applicable Documents.
- 4.15 Whether the dispute resolution mechanism provided in the Market Commercial Code is adequate to settle disputes among market participants or otherwise?**
- 4.15.1 MO submitted that apart from some language clarity, no change has been proposed by MO in the dispute resolution mechanism that has already been approved by the Authority.
- 4.15.2 SO submitted that according to the dispute resolution mechanism in the MCC, SO has a similar treatment as any other Service Providers/Market Participants. However, SO is technical arm of the Regulator with substantial jurisdiction by virtue of SO license and the Grid Code. Therefore, it is requested that any dispute arising between SO and MO functions may please be settled at Authority level. SO further requested that any provisions in the MCC which undermines the SO function may please be removed from the Code.
- 4.15.3 KE commented that the dispute resolution mechanism provided in the MCC pertains only to market related issues, and any bilateral dispute between market participants will be settled as per their respective bilateral contracts.
- 4.15.4 RE First commented that the dispute resolution mechanism within the MCC must ensure accessibility, transparency, and fairness for all market participants and



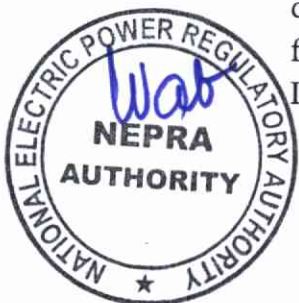




service providers. It should also be cost-effective to prevent financial burdens on smaller entities.

**Findings and Decision of the Authority:**

- 4.15.5 The Authority is satisfied that the dispute resolution mechanism in the approved MCC provides a clear, structured, and equitable process for the resolution of disputes. The mechanism affords parties the opportunity for amicable settlement as a first recourse, followed by reference to a sole expert mutually agreed upon by the parties, and ultimately, if necessary, recourse to the Authority or a tribunal constituted by the Authority.
- 4.15.6 Accordingly, the Authority decides that the dispute resolution mechanism as provided in the approved MCC annexed with this determination is adequate in form and substance and shall apply to all disputes arising under the MCC.
- 4.16 Whether the proposed delay of the legal separation of the CPPAG as MO and SPA for 5 years as opposed to the licensed obligation of 1 year is in violation of the terms and conditions of the license of MO? Whether the same will have any implications for CTBCM considering conflicts of interest between two functions?**
- 4.16.1 MO submitted that it has completed the functional segregation and has submitted a plan to the Authority regarding legal segregation vide letter dated 29th June 2022. It was submitted that the request to defer the legal separation of CPPA-G into the MO and the SPA is not a violation of the terms and conditions of the license, as MO has already included a request for extension in these timelines in the Final Test Run report. If this is graciously approved by the Authority, then a subsequent request will be filed to modify the conditions stipulated in the MO license granted by the Authority. Regarding the implications for CTBCM, it is stated that MO has ensured functional separation between MO and SPA, and both functions are working independently of each other. Therefore, the conflict of interest is immaterial in this case.
- 4.16.2 SO commented that the issue of conflict of interest between SPA and MO has been determined by the Authority since approval of high level CTBCM design. Moreover, MO also has a conflict of interest with SO. Association of BPCs and Generators are to be officially represented in BoD of MO (NEPRA approved CTBCM Detailed Design Section 16.5), which conflicts with the necessity of neutrality of SO during System Operations and Power System Planning. Furthermore, MO is the designated Contract Registrar whereas SO should have no knowledge of bilateral contracts and must carry out system planning and dispatch in neutral and transparent manner. In Pakistan's current regulatory framework, Power Acquisition Program (PAP) of DISCOs is strictly based on IGCEP, and system dispatch is central. Thus, decisions of institutional







arrangement of SO, MO and SPA should be taken while considering the abovementioned points. SO suggested that functional separation/ring-fencing should be maintained between SO & MO cadres, keeping in view the current regulatory framework.

- 4.16.3 KE commented that a holistic evaluation be done, to assess any possible implications on effective implementation of CTBCM including the possibility of conflict of interest, that may arise due to delay in completion of these actions.
- 4.16.4 RE First commented that the proposed delay in the legal separation of MO and SPA creates a significant conflict of interest. The Authority may ensure that these functions are distinct and independent. MO should establish an independent committee under its board, comprising power market experts for the MO, and a separate committee for the SPA, to maintain transparency and unbiased decision-making.

**Findings and Decision of the Authority:**

- 4.16.5 The Authority notes that, pursuant to the restructuring approved by the Federal Government, the ISMO has been established, and vide determination dated April 30, 2025, both the MO and SO licences have been duly transferred to the ISMO. This completes the requirement of functional and legal separation of the MO from the agency functions of CPPA-G as envisaged under the CTBCM framework.
- 4.16.6 At the same time, the Authority observes that structural or legal separation, while necessary, cannot alone guarantee the independence required for credible system and market operations. Global precedents consistently demonstrate that the effectiveness of market reforms depends not only on institutional restructuring but also on ensuring that the operators exercise autonomy in their decision-making. The credibility of a competitive electricity market depends on the assurance that operational and settlement decisions are taken neutrally, based on transparent technical and economic criteria, and are not perceived as influenced by external considerations.
- 4.16.7 In this regard, the Authority emphasizes that mandate of the ISMO flows from the licensing framework under the NEPRA Act. ISMO must discharge its responsibilities in a manner consistent with neutrality, transparency, and independence under regulatory oversight, thereby reinforcing investor confidence and market integrity.







**4.17 Whether the restructuring of System Operator as obligated in its licence has been carried out? Whether delay in the legal separation of NTDC as System Operator and Transmission Network Operator will have any impact on the CTBCM?**

4.17.1 MO submitted that NGC will be in a better position to respond to the restructuring of the SO as obligated in its licence. Regarding the impact on CTBCM, it is submitted that CTBCM can be implemented without any issue even when the SO is embedded in NGC, however, it's functioning as a separate entity from any network licensee will add further transparency and credibility to its role which is important for market transparency and liquidity. Further, it is reiterated again that the Federal Government is working on a proposal to establish the ISMO by merging the functions of the SO and MO as per the CTBCM plan approved by the Federal Government.

4.17.2 SO commented that it remains fully committed to the discharge of its licensed obligations. It was stated that, since May 2022, the function of SO has been overseen through a dedicated Deputy Managing Director (System Operation), under whose domain the power system planning function has also been placed. Further, dedicated positions in the areas of Human Resource, Finance, and Legal have been created to reinforce functional separation. It was further apprised that work on the legal separation of the SO for the establishment of an Independent System Operator is underway pursuant to the directions of the Board of Directors of NGC.

4.17.3 KE commented that a holistic evaluation should be done, to assess any possible implications on the effective implementation of CTBCM, including the possibility of conflict of interest that may arise due to the delay in completion of these actions.

4.17.4 RE First commented that the separation of the SO and TNO is crucial for maintaining operational integrity and avoiding conflicts of interest between the critical roles of systems operations and network operations, respectively. The restructuring process must be expedited to ensure CTBCM's success.

**Findings and Decision of the Authority:**

4.17.5 The Authority reiterates its findings, observations, and decision on Issue 4.16 above.

**4.18 Whether the recommendation to deal with excess transmission losses of transmission companies outside of the market commercial code as opposed to the provision of the approved market commercial code is justified?**

4.18.1 MO submitted that this recommendation has been made by considering the fact that dealing with the excess losses of a transmission licensee is a regulatory matter







and beyond the scope of functions performed by the MO. As the cap on losses for any transmission licensee is set by the Authority, the enforcement of such a cap also falls under the ambit of regulation rather than market operations. The internal consultant has also supported the opinion of MO in this regard.

- 4.18.2 KE commented that the mechanism regarding the treatment of excess losses of Transmission Service Providers has been omitted from the revised MCC submitted by the MO for approval of the NEPRA Authority. However, the issue of treatment of excess transmission losses of transmission companies is critical considering its possible implications on market participants. Therefore, it is important that the regulatory framework provides a clear mechanism with detailed illustration and in consultation with stakeholders for adjustment to be provided to Market Participants in respect of transmission losses in excess of NEPRA's approved losses.

**Findings and Decision of the Authority:**

- 4.18.3 The Authority observes that Transmission and Transformation (T&T) losses are approved as part of the investment plans and tariff determination. Once determined, such targets constitute binding obligations upon the transmission licensees. It is further observed that transmission losses, by their very nature, are technical and not commercial. They are computed through CDP metering of high accuracy class with dedicated CTs and PTs as mandated under the Grid Code, leaving little scope for errors. Accordingly, any financial impact arising from excess losses must rest squarely with the licensee and cannot be transferred to market participants. Conversely, where actual losses fall below the approved benchmark, due recognition is given through appropriate regulatory adjustments.
- 4.18.4 In this context, the Authority finds that the inclusion of a separate mechanism within the MCC to impose financial consequences upon transmission licensees for violation of loss targets is inconsistent with the overall regulatory framework. Such matters fall within the regulatory domain of tariff determination and approval of investment plans. Retaining such provisions in the MCC would amount to duplication and create regulatory inconsistency.
- 4.18.5 At the same time, the Authority is of the view that transparency and accountability within the market framework requires that any impact of violation of loss targets by transmission licensees is duly calculated and reported. Therefore, the Authority hereby directs the MO to periodically compute any breach of the approved limits by transmission licensees and submit the same, along with the resulting commercial impact on market participants, to the Authority for consideration in the relevant regulatory proceedings and in accordance with the MCC.







- 4.18.6 Further to the above, the Authority has decided to delete the mechanism contained in the MCC approved in 2022 for addressing excess transmission losses. The treatment of such losses shall be dealt with through approval of respective investment plans and tariff determinations.
- 4.19 Whether the Market Commercial Code adequately addresses the settlement treatment of excess transmission losses by NTDC and DISCOs, as well as treatment of inter-DISCO losses considering the fact that UoSC shall be charged on uniform basis?**
- 4.19.1 MO submitted that the MCC has comprehensive provisions regarding the treatment of these losses in the network. The distribution losses will be applied as per the benchmark specified by NEPRA in the Use of System Charges determination and the transmission losses will be applied on an actual basis. Regarding treatment of excess losses, the response is provided under Issue No. 18 above, which states that any excess loss by a transmission or distribution licensee is a regulatory matter and does not pertain to the functions being performed by the MO. Regarding the treatment of inter-DISCO losses in the presence of the uniform application of UoSC and losses, it is submitted that this matter relates to the tariff setting by NEPRA and does not relate to the function being performed by the MO under the MCC. As per the opinion of the MO, the uniform application of UoSC and the losses do not create any implications for any DISCOs as there is already a uniform tariff in place in the country. In fact, it is due to this uniform tariff that the UoSC and losses shall be charged on a uniform basis across the country. If there were no uniform tariff and consumers were paying the tariff of the respective DISCO, then the UoSC and losses would also not be uniform and would relate to the particular DISCO in which the consumer is located.
- 4.19.2 KE commented that the mechanism regarding the treatment of excess losses of transmission service providers has been omitted from the revised MCC. The Commercial Code is the basic document governing market operations and related transactions; therefore, treatment of excess losses beyond the benchmark set by the Authority should also be covered in the same for transparency and smooth transition towards bilateral transactions. In this regard, KE requested that clarity be provided in the Commercial Code on the compensation mechanism, along with a detailed illustration for adjustment to be provided to Market Participants in respect of losses in excess of NEPRA's approved losses. Further, KE submitted that UoSC be imposed on a uniform basis across the country till the time the uniform tariff is applicable. With reference to the treatment of inter-DISCO losses, KE was of the view that in case of inter-DISCO transaction, the transmission and distribution losses obligations shall be borne by recipient DISCO as the recipient DISCO is responsible for its load and the loss incurred against fulfilment of its load requirement. Moreover, KE proposed to provide







detailed mechanism / methodology for treatment of inter-DISCO settlement with respect to UoSC in the MCC.

**Findings and Decision of the Authority:**

- 4.19.3 The Authority observes that the MCC provides a comprehensive and uniform framework for the treatment of network losses in market settlements. The MO shall apply the uniform distribution losses in accordance with the determination of the Authority at each voltage level, based on the location of the metering point. With regard to transmission losses, the MCC provides that such losses shall be calculated on an actual basis through CDP metering of the high accuracy class, with the difference between injections and withdrawals forming the quantum of loss.
- 4.19.4 The Authority further notes that the treatment of uniform application of UoSC and losses across DISCOs is necessitated by the uniform tariff regime under the existing statutory and policy framework. Any inter-DISCO differentials arising on this account are already addressed under existing tariff mechanisms, and the practice in vogue shall continue in accordance with the relevant regulatory instruments as amended or issued from time to time.
- 4.20 Whether the auxiliary consumption of NTDC grids should be treated as a purchase from the DISCOs as SOLRs or continued to be settled by MO as per practice in vogue?**
- 4.20.1 MO submitted that during the trial run, it was observed that the auxiliary consumption of NGC is not considered as a sale by the respective SoLRs, but these units are separately accounted for and charged to NGC by MO. However, as per the formulas for the BME in the MCC, these units must be considered as an integral part of the losses and socialized on all demand. This gives rise to inconsistency because there will be double charging as on one side, the market participants will be injecting additional units into the system to cover for these units, while on the other hand, they will also be paying for these units in the use of transmission system charges of NGC. Therefore, the FTR report recommends including these units in the sale of the respective SoLRs to avoid double charging. MO did not support the practice in vogue, as it will continue the existing inconsistency of double charging of these units. In such a case, the MO will need to consider these units as an integral part of the NGC loss and will socialize it on the whole demand, which will be in contradiction to the tariff determination of NGC which does not include the auxiliary consumption of NGC as part of its losses.
- 4.20.2 NGC submitted that there are 58 No. of identified and metered NGC essential auxiliary consumption CDPs. Average auxiliary consumption is around 30







million units per year. Furthermore, the 11 kV grid station auxiliary of NGC is critical to the operations of the 500/220 kV network, and its source is NGC rather than DISCOs. In addition, if an essential auxiliary is charged to NGC, then it will have to claim it as a prudent expense in the tariff, which is a time-consuming process. Therefore, treatment of NGC auxiliary may be allowed on the same lines as NGC T&T losses i.e., by means of control in NGC tariff, and energy delivered to DISCOs by the NGC may be adjusted by the amount of metered NGC auxiliary. NGC further suggested that auxiliary consumption may be allowed without charges up to the allowed limit of losses, because it is essential for the running of 500/200 kV network.

- 4.20.3 KE commented that auxiliary consumption related to NGC Grids should be charged to / borne by NGC.
- 4.20.4 RE First commented that the auxiliary consumption of NGC grids should be treated as a purchase from the relevant DISCOs at prevailing rates, reflecting their role as the SoLRs. This approach will ensure fair cost allocation and accurate accounting and settlement. It was submitted that similar practices have been implemented in the US, where grid operators like PJM Interconnection categorize auxiliary consumption as part of the overall market transactions, ensuring transparency and consistency in market operations.

**Findings and Decision of the Authority:**

- 4.20.5 The Authority observes that the matter of auxiliary consumption of the NGC requires a clear and consistent regulatory treatment to avoid ambiguity in market settlements and duplication of charges on market participants. The submissions of the MO have also been considered. The Authority notes that auxiliary consumption can be divided into two categories i.e. essential auxiliaries, required for the operation of grid stations; and non-essential auxiliaries for usage other than grid operations.
- 4.20.6 The Authority observes that the final treatment of auxiliary consumption is subject to determinations pertaining to transmission use of system charges and investment plans of NGC. Pending such determinations, the Authority decides that the essential auxiliary consumption of the NGC, required for the operation of grid stations, shall be provisionally treated as part of transmission losses. Conversely, non-essential auxiliary consumption, such as that of colonies or similar facilities, not being system-related, shall be provisionally charged to NGC by the respective DISCOs in their role as SoLR.
- 4.20.7 The Authority further directs that the MSP shall record and separately report the quantum of essential auxiliary consumption to ISMO, so that such data is







transparently maintained and appropriately reconciled in both market settlements and subsequent tariff proceedings.

**4.21 Whether the requirement of the market commercial code for Secured Metering System (SMS) installation on both primary and backup meters at all metering points has been fulfilled or otherwise?**

4.21.1 MO submitted that the MCC and its associated CCoPs stipulate the requirement of a secured metering system on both primary and backup meters. In this regard, NGC has completed the installation of the secured meters on all CDPs (more than 750) except a few, as mentioned in the FTR report. A dedicated metering department has also been established, which is remotely retrieving data from these meters and providing the same to MO for market as well as legacy contracts settlements. The system has been tested for about two years now and all of its issues are sorted out, and the data retrieved through this system is timely provided to MO for settlements. Regarding backup meters, MO submitted that the backup meters requirement is only for accuracy purposes or in case the primary meter fails. There are seldom any cases of meter failure. Regarding the accuracy, on all generation CDPs, the backup meters are installed and only need to be integrated into the Secured Metering System to enable remote retrieval of data from such meters. On CDPs between NGC and DISCOs and inter-DISCO CDPs, the backup meters are also required to be installed along with their integration with the secured metering system of NGC. MO highlighted that all current transactions with trillions of rupees are being done based on this existing metering infrastructure and there have been no issues related to metering; therefore, the CTBCM can also start with this current metering infrastructure without any issue, and the improvements can be made along the way.

4.21.2 KE commented that as per Clause 18.2.1.1 of the approved MCC, KE is the metering service provider for its service area. In this regard, it was submitted that all primary meters installed at CDPs in the KE system are SMS enabled. Further, with respect to backup meters installed at CDPs in the KE service area, an assessment is being carried out and in case any additional investment is required for the installation of backup meters installed at CDPs, KE will approach NEPRA accordingly.

**Findings and Decision of the Authority:**

4.21.3 The Authority has observed that SMS meters have been installed at all CDPs except at the boundary points of PESCO–TESCO, which is addressed separately under issue no. 4.22. The MO has reported that the SMS has transmitted data in line with the requirements of the MCC and no such discrepancies were observed during the test run that could affect market settlement. However, the Authority has taken serious notice that back-up meters have not been installed at all CDPs.







Even though estimation procedures exist to address failures of primary meters, the absence of backup meters weakens confidence in the settlement process.

- 4.21.4 Nevertheless, absence of backup meters cannot be made a reason to delay CTBCM as availability of primary meters as well as estimation procedures sufficiently enable the MO to settle market transactions. Further, the MO has confirmed that CTBCM can commence with the existing metering infrastructure without any issue. In addition, actual market transactions will take place sometime after the CMOD, considering mandatory notice period requirements for BPCs under the NEPRA Act. The Authority, therefore, holds that commencement of CTBCM shall proceed on the basis of the existing primary meters. However, NGC is hereby directed to ensure installation of back-up meters at all CDPs within six (06) months of this determination and to submit monthly progress reports to the Authority.
- 4.21.5 The Authority further finds that the MSP department of NGC performs a critical function in securing accurate and reliable measurement of energy flows for market settlement. To discharge this role effectively, the said department must be adequately resourced and strengthened. Accordingly, NGC is directed to take necessary measures to reinforce the MSP department in terms of skilled manpower, processes, tools, and sufficient inventory of SMS-compliant meters, so that secure and transparent settlements under the MCC are ensured.
- 4.22 Whether the settlement of PESCO and TESCO is being performed currently in the absence of SMS between their boundaries and what are its potential implications regarding imbalances and capacity obligations of both DISCOs? What measures are being taken by PESCO and TESCO in this regard?**
- 4.22.1 MO submitted that in the absence of the telemetering enabled meters between the boundary of PESCO and TESCO, a joint settlement is being performed currently in which the combined allocation of PESCO and TESCO is used for their combined withdrawal for the purposes of calculating the imbalance. Further, the MSP has informed that the meters installed at these CDPs are capable of recording the hourly profiles which can be downloaded through optical cables and transferred to MSP. The metering committees of the metering points concerned need to download these profiles and share with MSP in a timely manner. Once the MSP provides this hourly data, then settlement can be performed on individual basis. Also, PESCO and TESCO have never violated their commercial allocation factor and therefore, have not been in imbalance during the trial run period. Regarding Capacity Obligations of PESCO and TESCO, it is submitted that the Capacity Obligations are not based on actual metering data, rather these are based on demand forecasts of these SoLR, therefore, this absence of hourly metering data has no impact on the determination of Capacity Obligations by the MO.







Regarding the measures taken by PESCO and TESCO, it is submitted that as per information obtained by MO, the PESCO and TESCO are collaborating with the metering service provider and procurement of meters is under process.

4.22.2 NGC submitted that, owing to the current configuration of SMS meters, the Energy/MDI of PESCO initially records the combined values of both PESCO and TESCO. This data is subsequently bifurcated on the basis of verified month-end metering data provided by TESCO, with an express disclaimer included in the settlement advice issued to CPPA-G. It was further explained that TESCO is in the process of procuring SMS meters compatible with NGC's Meter Data Management (MDM) server. Once installed, these meters will facilitate a complete 30-minute load profile. Until such time, however, the coincidental MDI of TESCO cannot be ascertained, though the non-coincidental bifurcated MDI is considered sufficient for application of the current NGC tariff. NGC also informed that the MSP Department has already undertaken initial testing of SMS-compliant meters of TESCO for integration with its MDM server which confirmed compliance with NGC's requirements.

4.22.3 TESCO initially submitted that there are forty-five (45) CDPs between its boundary and PESCO, on which revenue-class meters are currently installed and on the basis of which an annual settlement of approximately Rs. 60 billion is carried out. For the purpose of ensuring accurate monthly readings, meter-reading committees have been constituted from both DISCOs. It further informed that a tender for SMS meters, compliant with applicable requirements, has been concluded and a purchase order has also been issued. Later on, in August 2025, TESCO reported that forty (40) meters had already been installed, with the remaining in the process of being installed by PESCO in parallel.

#### **Findings and Decision of the Authority:**

4.22.4 The Authority finds that, as confirmed by MO, during the test-run, the settlement of TESCO and PESCO has been carried out without any issues. However, installation of SMS-compliant meters is a key requirement for smooth settlements of future transactions. In this regard, the Authority has noted that the SMS-compliant meters have been installed at the majority of CDPs at the boundary of PESCO–TESCO, with the remaining meters in the process of installation and integration. The Authority hereby directs that the ongoing installation must be completed without delay to secure the integrity of the settlement process. Further, PESCO, TESCO, NGC, and ISMO shall ensure strict compliance with MCC provisions in respect of boundary CDPs.







**4.23 Whether the System Operator is ready to shift the current merit order mechanism from a fortnightly basis to a daily basis? Additionally, whether the daily demand forecast prepared by System Operator required from DISCOs for efficient central economic dispatch is streamlined as required under applicable documents?**

4.23.1 RE First commented that the merit order, currently operating on a fortnightly basis in Pakistan, should transition to a daily basis to align with global practices and enhance market efficiency. Additionally, the SO must adopt more reliable forecasting methods, particularly for Variable Renewable Energy (VRE) generation, to ensure efficient dispatch and unit commitment leading to real time system operations. A relevant example is the system operator of Spain, Red Eléctrica, which has successfully implemented a daily merit order system, coupled with sophisticated forecasting techniques for VREs, contributing to more efficient and stable system operations.

4.23.2 SO commented that a dedicated portal has been created in SDXP for bilateral contract/merchant plants to declare Variable Operating Costs to the SO. However, as per Grid Code, the Merit Order of generators with legacy PPAs shall continue to be prepared by SPA (as custodian of PPAs) and communicated to SO. The SO shall merge the Variable Cost declarations provided by plants pertaining to market participants and SPA to create final Merit Order. Further, the development of the portal for preparation of merit order on daily basis has been completed. However, the actual applicability of daily Merit Order needs thorough testing to check accuracy and also assess its impact on dispatch in terms of operational constraints such as allowed number of unit startups, fuel supply management and startup times.

4.23.3 SO further submitted that the existing short-term demand forecast is primarily based on regression modelling/time-series analysis, which is highly dependent on data provided by DISCOs. The demand forecast provided by DISCOs is inaccurate and affects the accuracy of system-level demand projected for different studies. Another major challenge being faced currently is erratic and inconsistent demand pattern due to climate change and net metering. Moreover, after CMOD, the number of embedded generators connected in the distribution network will increase, which are beyond the scope of central dispatch. Therefore, SO requested that DISCOs be obligated to forecast their net power drawn from the National Grid after subtracting the power generated by embedded generators, as per Grid Code OC-2. Development of short-term demand forecast requires a wholistic and dedicated approach similar to the endeavors taken by MIRADs and SO to develop accurate long-term forecasts for IGCEP, as well as necessary provisions in the Distribution Code. The Power Dispatch Centers (PDCs) of DISCOs require upgradation to take up the afore-mentioned challenges.







4.23.4 KE commented that currently, EMO is prepared on fortnightly basis and the proposed transition towards day-ahead based EMO may have operational and administrative implications, including but not limited to frequent startups, shutdowns of machines etc. Accordingly, it is recommended that a suitable transitory period may be considered to ensure the readiness and robustness of the systems for preparation and implementation of day-ahead based EMO.

**Findings and Decision of the Authority:**

4.23.5 The Authority has examined the matter of implementation of the day-ahead merit order and notes that while the Market Operator has developed the requisite portal, its deployment must be preceded by rigorous testing. The Authority is mindful that dispatch decisions are constrained by operational realities, including the permissible number of unit start-ups, fuel supply coordination, and plant start-up times. Unless these constraints are factored into testing, the intended benefits of transparency and efficiency will not be realized. The Authority recalls that, vide directions dated July 9, 2025, ISMO, CPPA-G, and generation companies have been directed to proceed with the implementation of the day-ahead merit order. Those directions must be complied with in letter and spirit, with a compliance report submitted forthwith. The issue pertaining to daily demand forecasts is discussed in the following issue and may be referred there.

**4.24 Whether the necessary tools and capacity building have been undertaken by System Operator to prepare the daily load forecast for the efficient system operations as required under applicable documents?**

4.24.1 SO submitted that SCADA-III project includes a dedicated commercial Short-Term Demand Forecast tool called Rebase. Requisite input data has been provided to the vendor and development of the initial model is underway. The project schedule also includes operator training and capacity building for the said tool. In addition, NPCC has created a dedicated research & development department which is also working on development of an in-house tool for short term demand forecast.

**Findings and Decision of the Authority:**

4.24.2 The Authority has considered the submissions of the System Operator regarding the development of a short-term demand forecasting tool under the SCADA-III project, as well as the establishment of an internal R&D unit for this purpose. Although these initiatives are noted, the Authority observes with concern that despite repeated directions over time, the fundamental deficiency remains unresolved, namely, the failure of DISCOs to provide reliable and accurate demand forecasts.







4.24.3 The Authority is of the considered view that accurate forecasting is a non-negotiable obligation of the DISCOs. No forecasting tool, however advanced, can achieve its intended purpose in the absence of credible input data. The persistent failure of DISCOs to discharge this basic responsibility undermines the objectives of dispatch transparency, market efficiency, and price predictability. The continued reliance on inaccurate or delayed demand forecasts introduces systemic inefficiencies and exposes both market participants and consumers to unnecessary risks.

4.24.4 Accordingly, the Authority directs the SO and all DISCOs to jointly submit, within one (01) month of this determination, a comprehensive report on demand forecasting accuracy for the preceding year. This report shall include an hourly comparison of forecasted and actual demand and shall be accompanied by a structured plan to remedy existing deficiencies. The plan shall clearly identify short-term and long-term measures, with specific actions, timelines, and responsible departments. Failure to comply with these directions shall invite proceedings under the relevant provisions of the NEPRA Act.

## **5. Market Commercial Code**

- 5.1 The Authority has considered the submissions of the MO, the record of proceedings, and the comments made by stakeholders during the public hearing. The proposed amendments to the MCC and other matters pertaining to MCC have been deliberated at length in the preceding paragraphs.
- 5.2 The Authority observes that the MCC earlier approved in 2022 was for a limited purpose of facilitating the conduct of the FTR. Subsequent to that approval, significant developments have taken place during the implementation phase including but not limited to treatment of CGPs and renewable merchant generators. In the considered view of the Authority, piecemeal amendment of the 2022 MCC may create regulatory uncertainty. The Authority accordingly finds that only a consolidated and updated MCC can ensure the necessary clarity, predictability, and operational certainty for stakeholders, and provide a sound basis for the commencement of CTBCM upon CMOD.
- 5.3 The Authority further notes that the finalized MCC consolidates: (i) the amendments approved from among those proposed by the MO, (ii) the improvements identified during the proceedings of the FTR, and (iii) additional provisions introduced to address the participation of CGPs and RE merchant generators. Accordingly, upon due consideration, the Authority hereby approves the MCC annexed with this determination, as a new Code, which shall replace the version of the MCC approved in 2022.

## **6. Evolution of the CTBCM**

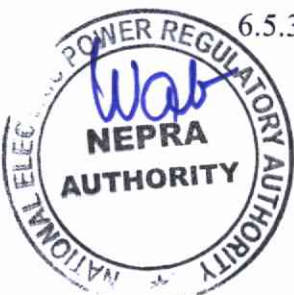
6.1 The Authority is mindful that the power sector of Pakistan faces structural challenges, including surplus contracted capacity caused by weak demand growth, financial







- constraints, and governance issues, which have historically impeded the pace of reforms. At the same time, the Authority is of the view that commencement of the CTBCM marks a credible first step towards competition, and its current design provides a sound basis for wholesale market operations.
- 6.2 The Authority emphasizes that market reforms, by their very nature, constitute an evolutionary process which must be pursued through a well thought-out reform process. However, the Authority is also mindful that undue delays erode confidence, perpetuate inefficiencies, and deny consumers the benefits of competition. It is therefore essential that reforms proceed with a disciplined pace supplanted with a clear roadmap so that progress is both credible and sustainable.
- 6.3 The Authority is of the considered opinion that in order to translate the full benefits of competition i.e. enhanced liquidity, greater consumer choice, and achieve the intended consequences of market reforms envisaged in the NEPRA Act, the evolution of the CTBCM must be pursued timely. Therefore, a forward-looking framework is required to guide the transition from bilateral contract markets toward more organized short-term markets and, ultimately, retail competition.
- 6.4 In light of these considerations, the Authority directs ISMO to prepare and submit, in consultation and coordination with all relevant entities, a comprehensive Market Evolution Design (MED) by 31st December 2026, duly taking into account a demonstrable global experience in market design and evolution. The MED, once approved, shall provide the basis for Phase II of the CTBCM, including the progressive lowering of the current 1 MW participation threshold. The Authority sets a target of 2030 for the commencement of Phase II, subject to satisfactory readiness to be demonstrated in the MED.
- 6.5 The Authority further directs that the MED shall be accompanied by a detailed implementation roadmap and shall, at a minimum, address the following:
- 6.5.1 Lowering of Market Participation Threshold – A phased roadmap for the progressive lowering of the 1 MW threshold, supported by policy, regulatory and institutional assessments, system readiness, and market management system capacity, together with timelines for transition towards retail competition while safeguarding consumer interests.
- 6.5.2 Phasing out of Costs Arising from Open Access – A comprehensive roadmap for addressing stranded and legacy costs associated with open access, to be phased out in a structured manner so as to avoid market distortions, protect consumers, and promote efficient price and investment signals.
- 6.5.3 Market Management System (MMS) Upgradation – A detailed plan to upgrade the MMS from its current footprint (~ 800 CDPs) to accommodate future growth (>100,000 metering points in Phase II and several million in retail phase),







including integration, scalability, cybersecurity, automation, and benchmarking against international equivalents.

- 6.5.4 Billing Systems Upgradation and Standardization with MSP Integration – A comprehensive assessment and roadmap for upgradation and standardization of billing systems to support accurate settlements, consumer switching, and phased arrangements for DISCOs to assume the role of Metering and Settlement Providers (MSPs).
  - 6.5.5 Organized Short-Term Market / Power Exchange – An assessment and proposal to evolve the wholesale electricity market from its current bilateral structure to an organized short-term market supported by an electronic trading platform, with the introduction of new trading products (day-ahead, intraday, financial hedging instruments), measures to deepen liquidity, and readiness requirements for participants.
  - 6.5.6 Procurement of Ancillary Services – A proposal with detailed roadmap for the establishment of a dedicated ancillary services market as a tradable product, informed by the experience of the framework incorporated in the MCC.
  - 6.5.7 Segregation of Supply and Distribution Businesses – An assessment and phased roadmap for unbundling of supply and distribution businesses, with transitional milestones to promote consumer choice, ensure fair competition, and mitigate conflicts of interest inherent in integrated operations.
- 6.6 The Authority further requires ISMO to submit biannual progress reports commencing from December 2025 to apprise the Authority of the status of MED development.

## **7. Outstanding Actions**

- 7.1 The Authority observes with serious concern that despite clear directions and well-defined responsibilities under the CTBCM Implementation Roadmap, several critical actions remain outstanding. These include, *inter alia*, the finalization of Security Package Documents by PPIB, submission of Connection Agreements for network licensees and generation companies by NGC/DISCOs, and the establishment of dedicated banking arrangements by DISCOs for settlement of market transactions with the MO. Although these actions are not pre-requisite for the CMOD, repeated deferrals of such actions have already contributed to avoidable delays in the reform process, which cannot be condoned any further. It is, therefore, required that all concerned entities shall discharge their respective obligations with diligence and without any further lapse.

- 7.2 The Authority emphasizes that the successful commencement of the market requires that these foundational steps, contractual, procedural, and operational, be completed in a coordinated and timely manner. Any further delay in execution not only weakens the







credibility of the reform process but also risks undermining the confidence of investors, market participants, and consumers.

- 7.3 The Authority directs that the outstanding actions must be completed immediately and without delay in their true letter and spirit, which will allow the market to function on a strong and sustainable footing, hence, enhancing the confidence of the market participants.

**8. Decision of the Authority**

- 8.1 The Authority, after detailed deliberation in the matter, has made its decision as well as issued necessary directions as reflected in Paras 4, 5, 6 and 7 of this determination for compliance.

**Authority**

Rafique Ahmed Shaikh  
(Member)

Amina Ahmed  
(Member)

Engr. Maqsood Anwar  
(Member)

Waseem Mukhtar  
(Chairman)

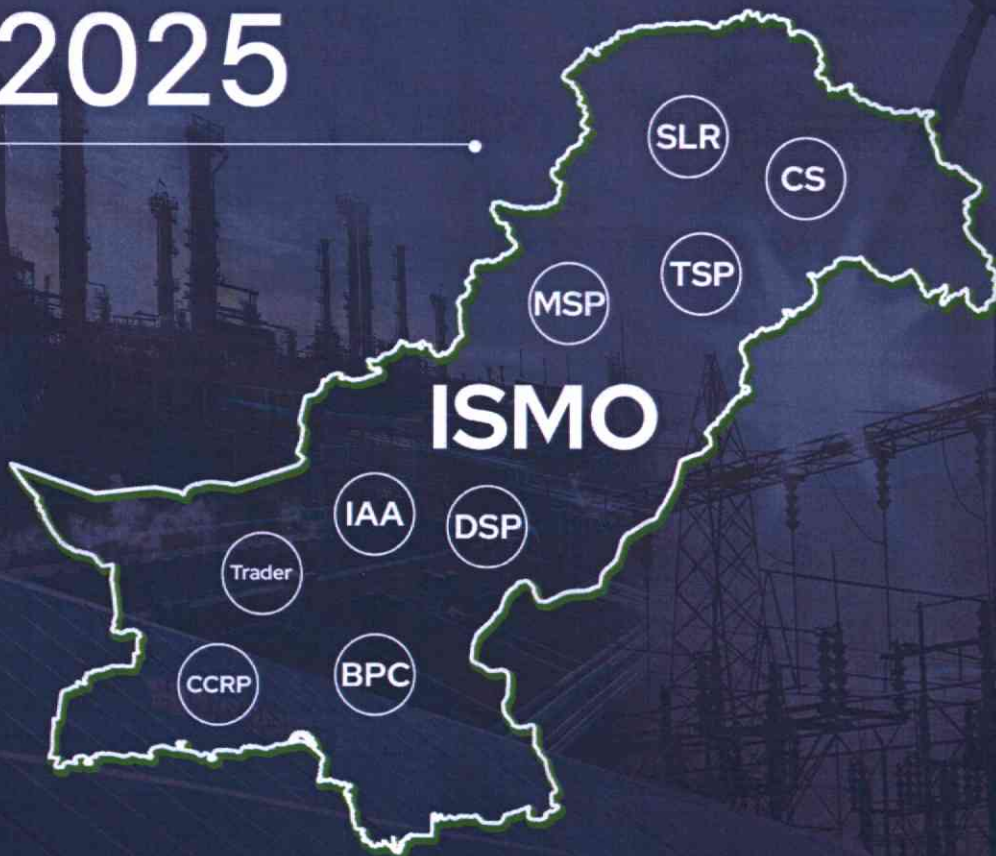






Independent System & Market  
Operator

# MARKET COMMERCIAL CODE 2025



APPROVED BY:  
NATIONAL ELECTRIC POWER REGULATORY AUTHORITY



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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 the 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, license, concurrence, authorization, registration and codes.

The roles of different entities are 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.

### I. 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/Units and issuance of Firm Capacity Certificates;



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- 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) administration of a settlement and payment system for the Capacity and Energy Balancing Mechanisms to clear differences between actual and contracted quantities;
- j) administration of a payment system for the Imbalances of Market Participants and other market charges, including the verification and registration of Security Covers; and
- k) administration of 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.

## I. 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.

## 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.
- f) The Captive Generator shall enrol as Market Participant if it intends to avail open access for self-consumption and all requirements for a Market Participant shall apply to the Captive Generator accordingly.

### 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-sell 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.



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### 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. Initially, at the start of the market, the National Grid Company and K-Electric shall perform the functions of Metering Service Providers in their respective service territories. However, in future, the role of Metering Service Providers may be assigned by the Authority to other entities as per the applicable regulatory framework.

### 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, in 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, 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 Suppliers of Last Resort (Ex-WAPDA DISCOs and KE 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 as the agent of Ex-WAPDA DISCOs and KE 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, especially in the approved CTBCM design, 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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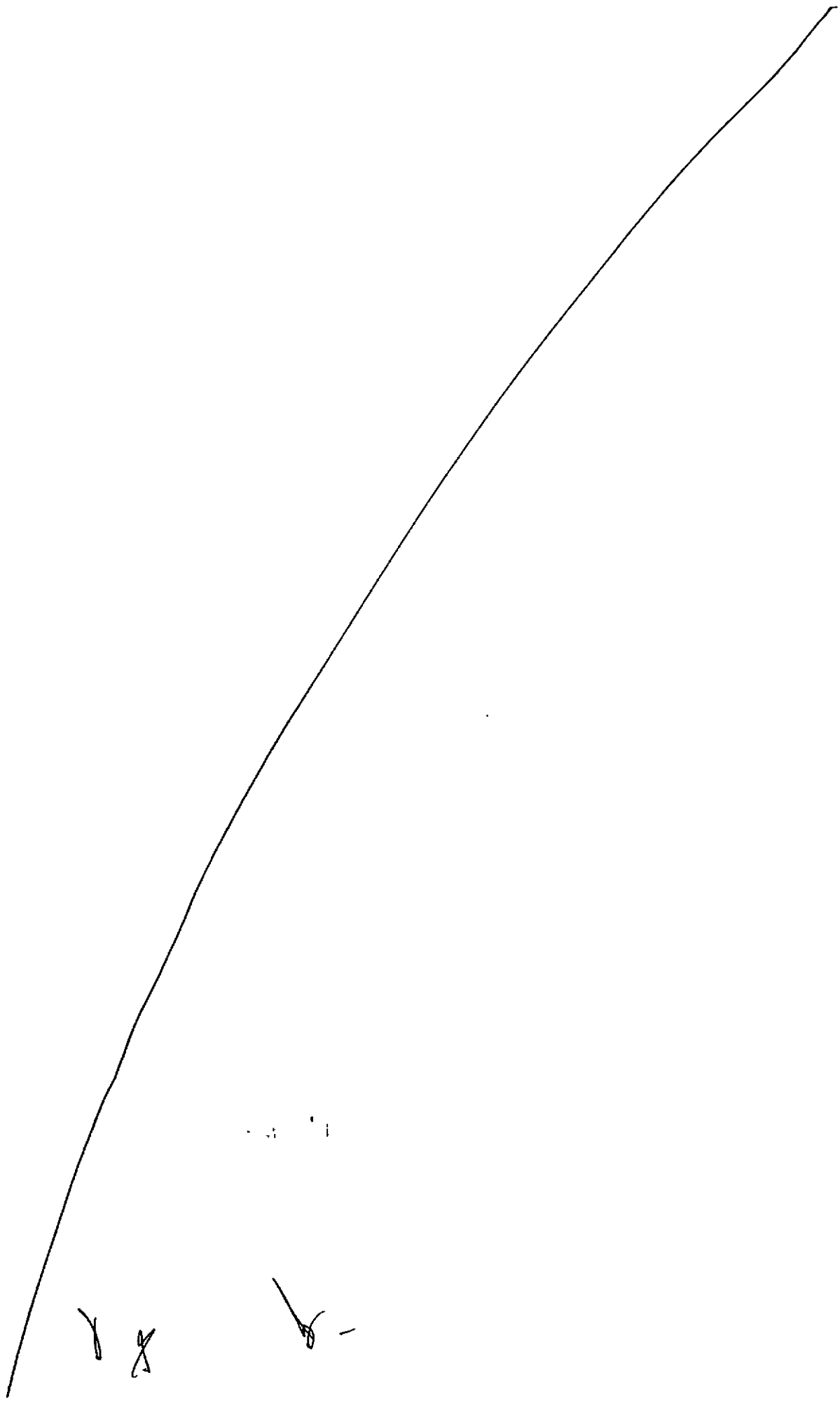




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# Acronyms

|        |                                                     |
|--------|-----------------------------------------------------|
| ARE    | Alternative and Renewable Energy                    |
| ASC    | Ancillary Services Charges                          |
| BMC    | Balancing mechanism for Capacity                    |
| BME    | Balancing mechanism for Energy                      |
| BPC    | Bulk Power Consumer                                 |
| 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       |
| DISCOs | Distribution Companies                              |
| EPA    | Energy Purchase Agreement                           |
| FSS    | Final Settlement Statement                          |
| FYSS   | Final Yearly Settlement Statement                   |
| IAA    | Independent Auction Administrator                   |
| IGCEP  | Indicative Generation Capacity Expansion Plan       |
| ISMO   | Independent System and Market Operator of Pakistan  |
| 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              |
| SLA    | Service Level Agreement                             |
| TSP    | Transmission Service Provider                       |
| WAPDA  | Water and Power Development Authority               |





# Commercial Code

## Chapter I. GENERAL CONDITIONS

### I.1. OBJECTIVES AND SCOPE

#### I.1.1. TITLE

I.1.1.1. This code shall be called the Market Commercial Code (the "Commercial Code" or the "Code").

#### I.1.2. OBJECTIVES

I.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 in the electric power market;
- d) to set out the rights and responsibilities of Market Participants in relation to buying and selling of electric power, settlement and payment 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.



#### I.1.3. APPLICABILITY

I.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 become 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. **"Adjudication Tribunal"** means a tribunal established by the Authority for resolution of disputes under the Commercial Code;
3. **"Adjudicator"** means a member of the Adjudication Tribunal to adjudicate a Dispute;
4. **"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;
5. **"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;
6. **"Agency Code"** means the code approved by the Authority for administration of Legacy Contracts-CPPA-G by the Special Purpose Agent.
7. **"Allocation Factor"** means a value, expressed in percentage, calculated as per provisions of National Electricity Policy and National Electricity Plan, 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/special purpose 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/special purpose agency agreement, as amended or replaced from time to time;
8. **"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;
9. **"Amendment Submission"** means the request for review or amendment of this Code, submitted as per provisions of this Code;
10. **"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;
11. **"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;
12. **"Ancillary Services"** has the meaning assigned to the term in the Grid Code;





13. **"Annual Loss Percentage"** shall have the meaning assigned to the term in Clause 11.5.3.1.
14. **"Applicable Law"** means the relevant laws of Pakistan including federal, provincial and local laws;
15. **"Applicant"** means any person who has filed an application to enrol with the Market Operator in accordance with the provisions of Chapter 2;
16. **"ARE Generator"** means a Generator which produces electric power through renewable resources;
17. **"Authority"** means the National Electric Power Regulatory Authority established under Section 3 of the Act;
18. **"Available Capacity"** means the share of the Dependable Capacity, which is available for dispatch by the System Operator at any specific period of time;
19. **"Availability Declaration"** has the same meaning assigned to the term in the Grid Code;
20. **"Back-feed Energy"** means the Energy consumed by a Generation Plant or Generation Unit, while the Generation Plant or Generation Unit is not dispatched;
21. **"Back-up Meter"** means a meter installed at the Metering Point to measure and record the Energy injected into or withdrawn from the Metering Point for checking or backup purposes as provided for in the Grid Code;
22. **"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;
23. **"Balancing Mechanism for Capacity"** means the mechanism, centrally administered by the Market Operator, to settle the Imbalances as defined in Clause 120.a;
24. **"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;
25. **"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;
26. **"Bulk-Power Consumer (BPC)"** shall have the meaning assigned to the term in the Act;
27. **"Business Day"** has the meaning assigned to the term in Clause 1.2.4.1;
28. **"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 18.2.9.1.c);
29. **"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;
30. **"Capacity and Associated Energy Supply Contract"** shall have the meaning assigned to the term in Section 3.3.2;



31. **“Capacity Balance”** shall have the meaning assigned to the term in Clause 9.2.5.1;
32. **“Capacity Balancing Period”** shall have the meaning assigned to the term in Clause 9.1.2.1;
33. **“Capacity Obligations”** shall have the meaning assigned to the term in Chapter 10;
34. **“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;
35. **“Captive Generating Plant”** shall have the meaning as assigned to this term in the Act;
36. **“Captive Generator”** means a person who owns and operates a Captive Generating Plant;
37. **“Category (in relation to a Market Participant)”** shall have the meaning as assigned to the term in Clause 2.1.1.2;
38. **“Chapter”** means a chapter of this Code;
39. **“Clause”** means a clause of this Code;
40. **“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;
41. **“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;
42. **“Code of Conduct”** shall have the meaning assigned to the term in Clause 1.3.1.13 of this Code;
43. **“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;
44. **“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;
45. **“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;
46. **“Company”** means a company registered under the Laws of Pakistan;
47. **“Competitive Market Operation Date” or “CMOD”** means the date set by the Authority for commencement of commercial operations of the CTBCM;
48. **“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;
49. **“Compliance with Capacity Obligations Report”** shall have the meaning assigned to the term in Sub-Section 10.6.1 of this Code;
50. **“Condition”** means a condition of this Code;





51. **“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;
52. **“Congested Area”** shall have the meaning assigned to the term in Sub-Section 6.2.1 of this Code;
53. **“Congested Zone”** means an area in the Transmission Network, established as per Sub-Section 6.2.1 of this Code, which consists of multiple Congested Areas and can be considered as an independent network having interconnections with other independent networks;
54. **“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;
55. **“Connect”** means a form of physical link to the Transmission or Distribution Network and related terms shall be construed accordingly;
56. **“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;
57. **“Connection Point”** means a point of connection between:
- a. a Transmission or a Distribution Network and a Generation Plant or a 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;
58. **“Contract Market”** means the Bilateral Contracts market established under this Code;



59. **“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;
60. **“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;
61. **“Credited Capacity”** means the Capacity allocated to a Market Participant in the Balancing Mechanism for Capacity and/or for verification of its compliance with the Capacity Obligations;
62. **“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;
63. **“Critical Hours”** are such hours of the previous year when the power system was under maximum stress as detailed in Sub-Section 9.2.1;
64. **“CTBCM” or “Competitive Trading Bilateral Contract 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;
65. **“Customized Contracts”** shall have the meaning assigned to this term in Clause 3.2.2.4;
66. **“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;
67. **“Default Amount”** means any amount a Market Participant/Transmission or Distribution Licensee has failed to pay on a Payment Due Date;
68. **“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;
69. **“Default Notice”** means the notice issued by the Market Operator to a Market Participant involved in an Event of Default;
70. **“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);
71. **“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;
72. **“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 Legacy Generators-KE, except solar and wind-based Generation Plants, the dependable capacity as determined through the initial/annual dependable capacity tests performed and notified by the KE as per its PPAs or EPAs or service level agreements (SLAs).
  - c. 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.
  - d. For other Generators, the value certified by the System Operator as per provisions of the Grid Code.
  - e. For Captive Generators, value certified by a credible independent engineer, approved by the System Operator;
73. **"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;
  74. **"Designated Bank"** means the bank selected jointly by 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;
  75. **"Dispatch"** shall have the meaning assigned to the term in the Grid Code.
  76. **"Dispatch Day"** means a period in the Dispatch process from 00.00 hours to 23.59 hours in the same calendar day;
  77. **"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;
  78. **"Dispatch Period"** means every sixty-minute interval, or such other shorter interval as provided in the Grid Code, during a Dispatch Day;
  79. **"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;
  80. **"Dispute"** means any dispute or disagreement or difference arising under this Code or any provision hereof as specified in Chapter 14;
  81. **"Distribution Company" or "DISCO"** means a distribution company Licensed by the Authority to engage in the distribution of electric power;
  82. **"Distribution Code"** means the distribution code prepared by the Distribution Licensees and approved by the Authority;
  83. **"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;



84. **"Distribution Network Connected Generation"** means a Generation Plant or Generation Unit directly connected to a Distribution Network;
85. **"Distribution Network Service Provider"** means a Distribution Licensee which provides, inter alia, Open Access;
86. **"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;
87. **"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;
88. **"Electric Power Supplier"** shall include Competitive Supplier and Supplier of Last Resort;
89. **"Electric Power Trader"** means a person Licensed by the Authority under section 23C of the Act;
90. **"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 of downloading such information;
91. **"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;
92. **"Energy Balancing Period"** shall have the meaning assigned to the term in Clause 5.1.2.1;
93. **"Energy Limited Generation Unit"** means a Generation Unit whose capability to produce Energy is constrained by the availability of the primary energy stored;
94. **"Enrolled Person"** means a person who is enrolled with the Market Operator as per provisions of Section 2.10 of this Code;
95. **"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;
96. **"Event of Default"** means events defined in Clause 16.2.1.1 of this Code;
97. **"Excess Losses"** means the amount of Transmission losses, expressed in kWh or multiples of kWh, which exceeds the maximum value of losses allowed by the Authority in the relevant Tariff determination;
98. **"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;
99. **"Extraordinary Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 7.3.4;
100. **"Extraordinary Yearly Settlement Statement"** shall have the meaning assigned to the term in Sub-Section 11.3.4
101. **"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;
102. **"Final Settlement Statement"** shall have the meaning assigned thereto in Sub-Section 7.3.3;
103. **"Final Yearly Settlement Statement"** shall have the meaning assigned thereto in Sub-Section 11.3.3;





104. **"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;
105. **"Firm Capacity Certificate"** means a certificate issued by the Market Operator to:
- 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;
  - EX-WAPDA DISCOs for Legacy Contracts-CPPA-G or Legacy Contract-DISCO, as the case may be; or
  - KE for its own Generators or Legacy Contracts-KE or Legacy Contracts-CPPA-G.
106. **"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;
107. **"Fiscal Year"** means a period of twelve (12) months starting from 1<sup>st</sup> July and ending on 30<sup>th</sup> June;
108. **"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;
109. **"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;
110. **"Generation Following Supply Contract"** shall have the meaning assigned to the term in Section 3.3.1;
111. **"Generation Plant"** means a Generation Unit or group of Generation Units, connected to the Transmission or Distribution Network at a single Connection Point;
112. **"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;
113. **"Generator"** means a Generation Company or a Captive Generator, as the case may be;
114. **"GoP"** means the Government of the Islamic Republic of Pakistan;
115. **"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;
116. **"Grid System"** means the Transmission and Distribution Network owned and operated by the Transmission and Distribution Licensees;
117. **"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;
118. **"Guaranteed Capacity"** shall have the meaning assigned to the term in Clause 3.2.1.5.a)



119. **“Identification Code”** is an alphanumeric 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:
- by the Market Operator to the Market Participants during the enrolment process;
  - by the System Operator to the Generation Plants or Generation Units according to the provisions of the Grid Code; and
  - by the Metering Service Provider to the Metering Points;
120. **“Imbalance”**
- 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;
  - 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;
121. **“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;
122. **“Initial Firm Capacity Certificate”** means the Firm Capacity Certificate issued by the Market Operator:
- Before CMOD, for those Generation Plants which were existing prior to the CMOD;
  - At the time of commissioning, for those Generation Plants which are commissioned after CMOD;
123. **“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;
124. **“K-Electric” or “KE”** means K-Electric Limited Licensed by the Authority;
125. **“Legacy Contract-CPPA-G”** shall have the same meaning as assigned to the term Legacy Contracts in the Agency Code;
126. **“Legacy Contract-DISCOs”** means a PPA or EPA signed or administered by any of EX-WAPDA DISCO before the CMOD;
127. **“Legacy Contract-KE”** means a PPA or EPA signed and administered by KE before the CMOD. Any SLA between KE and its existing Generator, finalized after CMOD, shall also qualify as Legacy Contract-KE.
128. **“Legacy Generator-CPPA-G”** means a Generator or an Import contracted through a Legacy Contract-CPPA-G.
129. **“Legacy Generator-DISCOs”** means a Generator or an Import contracted through a Legacy Contract-DISCO.





- 130. **“Legacy Generator-KE”** means a Generator or an Import contracted through a Legacy Contract-KE. For the avoidance of doubt, the Generators owned by KE prior to CMOD, also fall under this definition.
- 131. **“Licence”** shall have the meaning assigned to the term in the Act and the word “Licensee” shall be construed accordingly;
- 132. **“Load Facility”** means a facility that consumes Energy;
- 133. **“Load Following Supply Contract”** shall have the meaning assigned to the term in Section 3.3.3;
- 134. **“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;
- 135. **“Market”** means the Competitive Trading Bilateral Contract Market (CTBCM);
- 136. **“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;
- 137. **“Market Operator”** means the person Licensed by the Authority to perform the functions of the Market Operator;
- 138. **“Market Operator Fee” or “MO Fee”** means the fee determined by the Authority for the Market Operator services;
- 139. **“Market Participant”** means any person who is enrolled with the Market Operator and has also executed a Market Participation Agreement;
- 140. **“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;
- 141. **“Market Participation Agreement”** means the agreement executed by the Market Operator with another person who had applied to enrol as a Market Participant;
- 142. **“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;
- 143. **“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;
- 144. **“Meter”** means a device that measures electrical energy as per specifications of the Grid Code or Distribution Code, as the case may be;
- 145. **“Metering Incident Report”** means a report prepared by the Metering Service Provider in the cases provided in Clauses 4.3.2.2 and 18.2.2.3;
- 146. **“Metering Point”** means a Connection Point, equipped with a Commercial Metering System which is periodically read by an authorised Metering Service Provider;
- 147. **“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;



148. **“Minor Non-Compliance”** shall have the meaning assigned to the term in Clause 10.5.4.6;
149. **“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;
150. **“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;
151. **“National Transmission and Despatch Company Limited” or “NTDC” or “National Grid Company”** means the national grid company Licensed by the Authority;
152. **“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;
153. **“Notice of Dispute”** shall have the meaning assigned to the term in Clause 14.3.1.1;
154. **“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;
155. **“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 Advice(s) for the whole Fiscal Year;
156. **“Payment Due Date”** means the date of the second (2<sup>nd</sup>) Business Day after the issuance of the Debit Advice or provided otherwise for payment of a specific amount under a Debit Advice;
157. **“Permanent Firm Capacity Certificate”** means a Firm Capacity Certificate granted pursuant to Clause 8.3.1.7 that can be used to register Contracts with the Market Operator involving Capacity transactions;
158. **“Physical Asset”** for the purposes of this Code, means a Generation Unit of a Generation Plant which is clearly identified;
159. **“Preliminary Settlement Statement”** shall have the meaning assigned to the term in Sub-Section 7.3.1;
160. **“Preliminary Yearly Settlement Statement”** shall have the meaning assigned to the term in Sub-Section 11.3.1;
161. **“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;
162. **“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;





163. **“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:
- for providing Ancillary Services; or
  - allowing the provision of Ancillary Services by other Generation Units;
164. **“Reference Technology”** shall have the meaning assigned to the term in Clause 9.2.6.10;
165. **“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;
166. **“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;
167. **“Reserve Margin”** shall have the meaning assigned to the term in Clause 9.2.4.3;
168. **“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;
169. **“Section”** means a section of this Code;
170. **“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;
171. **“Security Constrained Economic Dispatch” or “SCED”** shall have the meaning assigned to the term in the Grid Code;
172. **“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;
173. **“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;
174. **“Serious Non-Compliance”** shall have the meaning assigned to the term in Clause 10.5.4.6;
175. **“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;
176. **“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;



177. **"Settlement"** means the process of calculating charges to be paid by and to Market Participants or Service Providers under this Code;
178. **"Settlement Guarantee Cover"** means the Guarantee Amount deposited by a Market Participant;
179. **"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;
180. **"Settlement Software"** means the suite of computer programmes used by the Market Operator to calculate the Settlement amounts under this Code;
181. **"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;
182. **"Special Purpose Agent"** means 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.;
183. **"Standardized Contracts"** shall have the meaning assigned to the term in Clause 3.2.2.2;
184. **"Sub-Section"** means a Sub-Section of this Code;
185. **"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;
186. **"Supply License" or "Electric Power Supply License"** means a License issued by the Authority under section 23E of the Act;
187. **"Suspended Participant"** is any Market Participant who has received and is the subject of a valid and continuing Suspension Order;
188. **"Suspension Order"** means an order issued by the Market Operator pursuant to Sub-Section 16.2.3;
189. **"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 Section 19.1 of this Code;
190. **"System Operator"** means a person licenced by the Authority under section 23 G of the Act;
191. **"System Operator Fee"** means the fee determined by the Authority for the System Operator;
192. **"System Peak Hours"** means the hours included in the period between, 1100 hrs to 1700 hrs (6 hrs) and 2000 hrs. to 0100 hrs (5 hrs). for the months of June, July, August, and September;
193. **"Tariff Determination"** means a determination whereby the Authority approves tariff, rates, charges and other terms and conditions for provision of electric power services;





194. **"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;
195. **"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;
196. **"Termination Date"** means the date on which a Market Participation Agreement expires or the same is terminated by the Market Operator;
197. **"Termination Order"** means an order issued by the Market Operator pursuant to Clause 16.2.4.1;
198. **"Total Demand"** means the total Demand of the system, calculated pursuant to the provisions of Sub-Section 5.4.2;
199. **"Trading Period"** means the period for which an Energy transaction or a Capacity transaction is allowed as defined in Clause 3.2.1.2;
200. **"Trading Point"** means a Metering Point at which commercial transactions (buying or selling of Energy or Capacity) may take place;
201. **"Transmission Licensee"** means a person Licensed by the Authority under sections 16, 17, 18A or 19 of the Act;
202. **"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;
203. **"Transmission Network"** means transmission facilities owned, operated, managed or controlled by a transmission licensee and used for the movement or delivery of electric power;
204. **"Transmission Service Provider" or "TSP"** means the holder of a Transmission License issued by the Authority and is enrolled with the Market Operator;
205. **"Transmitted Energy"** means the Energy which has been transported through the Transmission Network;
206. **"Urgent Amendment"** shall have the meaning as assigned to the term as per Clause 1.3.7.1;
207. **"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;
208. **"Variable Generation Cost"** means the costs which vary with the change of the output of a Generation Unit; and
209. **"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.



## I.2.2. INTERPRETATION

I.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.

I.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 and vice versa;
- 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 or agreement 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.

## I.2.3. RIGHT OF INTERPRETATION

I.2.3.1. The Market Operator shall implement, apply, and enforce the provisions of this Code.

I.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.



## I.2.4. TIMES AND DATES

I.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 the System Operator of an Affiliate of such person except the members of the Market Operator and the System Operator who both will belong to the ISMO.;
- 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 from private sector.
- b) One representative of ARE Generators including hydro power plants from private sector;
- c) One representative of WAPDA;



- d) One representative of the National Grid Company;
- e) One representative of the Provincial Grid Companies;
- f) One representative of the EX-WAPDA DISCOs;
- g) One representative of K-Electric;
- 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 representative of the System Operator;
- l) One representative 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 Pakhtunkhwa, 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 representative of the System Operator shall be appointed by the ISMO;
- k) The representative of the Market Operator shall be appointed by the ISMO; and
- l) The representative 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 such member shall be nominated by the CCRP.
- 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.
- 1.3.1.13. The CCRP shall comply at all times with its Code of Conduct, which shall be developed by the Market Operator, and approved by the CCRP, within three (3) months of the approval of this Code. This Code of Conduct shall provide procedures for smooth functioning of the CCRP and shall include, inter-alia, procedures regarding nomination of Code Participants under Clause 1.3.1.10, meeting frequency, quorum, voting, decision recording, etc.

### 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:
- statistics of transactions in the market;
  - problems identified in the implementation of the Commercial Code, and the CCOPs;
  - interpretations made for this Code by the Market Operator, and any conflicts of interpretation of this Code with Market Participants or Service Providers;
  - 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
  - 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.

#### I.3.4. PROCEDURE FOR REVIEW OR AMENDMENT OF COMMERCIAL CODE

I.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 the following:

- a) the Part, Chapter, Section, Sub-Section, Clause, or Appendix to be amended;
- b) a clear justification of the Amendment Submission, including on any distortion, gap or issue of concern in the existing Code;
- c) description on how the Amendment Submission would address the issues and conditions identified in the justification;
- d) an indicative or summary text proposed for the Amendment Submission;
- e) any other information and relevant supporting documents necessary to explain and justify the Amendment Submission.

I.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.

I.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.

I.3.4.4. While considering an amendment to this Code, the CCRP may take into consideration the opinion of the CCWG, however, such opinion shall not be binding on the CCRP.

I.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 I.3.4.12.



I.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.

I.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.

I.3.4.8. The CCRP shall provide notice of meetings to any relevant Market Participant or other interested persons, to participate in the meetings.

I.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.

I.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.

I.3.4.11. Upon completion of the report referred to in Clause I.3.4.10, the CCRP shall refer the matter to the Market Operator for onward submission to the Authority for approval of the recommendations. For the purposes of clarity, if the CCRP does not agree with the proposal to amend the Code and decides not to recommend the Amendment Submission to NEPRA, the reasons for such non-recommendation shall be submitted to the Authority for information.

I.3.4.12. 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.



#### 1.3.4.13. 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 (same as in Clause 1.3.4.1) 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 1.3.4.13 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 1.3.4.13 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 d 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.

### 1.3.9. EXEMPTION FROM THE COMMERCIAL CODE

1.3.9.1. All requests for exemption from this Code shall be submitted to the CCRP and thereafter processed and examined by the CCRP.



1.3.9.2. The CCRP after thorough evaluation, *mutatis mutandis*, in accordance with procedure set out in Clauses 1.3.4.6 to 1.3.4.13 shall make recommendations to Authority for approval or rejection of the proposed exemption.





## 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-CPGA-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 for enrolment as Generator, shall have a valid generation License or a concurrence 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 for enrolment as an Electric Power Supplier, shall have a valid Electric Power Supplier License;
  - a.3. if the application is for enrolment as an 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 enrolment as a Generator or a BPC or their representative, the person has to certify that a Commercial Metering System has been installed 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 the 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) submit to the Market Operator, in a timely manner and to the best of its knowledge, the information required to be submitted as 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;
- b) pay on or before the Payment Due Date, any Amounts Payable to the Market Operator;
- c) maintain a Security Cover and Guarantee Amount as required by the Market Operator as specified in this Code; and
- d) maintain a bank account for the administration of the market payment system;
- e) 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) detailed 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 form;
- 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 a 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 in writing:

- a) that it has received the Admission Application, any other documents as required in 2.3.1.3 and the relevant 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 is not in accordance with the stipulated requirements 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 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 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:
- enrolment of a new Market Participant;
  - issuance of a Suspension Order;
  - termination or withdrawal;
  - 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 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:

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

- 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;
- 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 capable of being remedied prior to the issuance of a 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. ENROLMENT OF SERVICE PROVIDERS

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. RIGHTS AND OBLIGATIONS OF THE SERVICE PROVIDERS

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) detailed requirements to enrol 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 form;
- d) detailed procedure for approval or 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; and
- 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 a 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; or
- 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 of 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 connected to the Grid System which may have an impact on the administration or settlement of the Market.



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) by 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 capable of being remedied 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 issuance of a 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. Provided that the Market Participant representing the Enrolled Person may complete all these steps on behalf of the 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 a Market Participant or as a Service Provider or as an 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. The amount of fee recovered herein shall be made part of the petition for the determination of the Market Operator Fee for approval by the Authority.



## 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; or
- 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 with respect to balancing mechanisms, market settlement and verification of compliance with Capacity Obligations; provided that it will be decided by the Market Operator whether certain information, excluding the prices, is commercially sensitive or not, subject to the condition that the Market Operator shall provide the justification in writing to the parties before reviewing such information;

- 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 may either 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 may either be a Generator, an Electric Power Trader or an Electric Power Supplier and the buyer either may be an Electric Power Supplier, an Electric Power Trader or a BPC; For the purposes of clarity, where the buyer is a BPC, the seller in the Contract shall be an Electric Power Supplier.
- 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 assigned to 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; For the purposes of clarity, where the buyer is a BPC, the seller in the Contract shall be an Electric Power Supplier.
- 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 assigned to 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 of its production by the seller or not;
  - d.2. considered to be bought by the buyer, regardless of its usage (consumption) 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 assigned to 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.
- f) The compensation for Transmission Must Run, Reliability Must Run and Ancillary Services will be assigned to the seller.

### 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 Bilateral 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.

### 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.

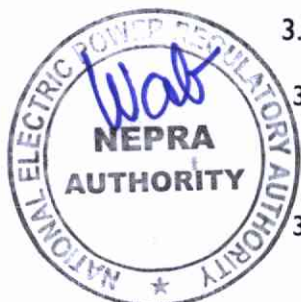
#### 3.5.2. APPLICATION FOR CONTRACT REGISTRATION

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;
- c) 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
- d) 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 16.2.4.

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 16.2.3, 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 (60) 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 (7) 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 (15) 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 supply electricity to the BPC, subject to fulfilment of requirements of the relevant 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 twenty (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 3.6.6.1.



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 3.6.6.

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 3.6.6; 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 16.2.3 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 16.2.4, 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 3.6.4.1 or 3.6.4.2, 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. DEREGISTRATION OR SUSPENSION DUE TO DEFAULT UNDER A USE OF SYSTEM AGREEMENT

3.6.5.1. Where the Distribution Network Service Provider informs the Market Operator that a Market Participant has defaulted under the use of system agreement, the Market Operator shall immediately suspend all such Contracts of the concerned Market Participant that fall within the ambit of such use of system agreement.





3.6.5.2. Where the Distribution Network Service Provider informs that the concerned Market Participant has not remedied its default and the use of system agreement has been terminated, the Market Operator shall deregister all such Contracts of the concerned Market Participant that fall within the ambit of such use of system agreement.

3.6.5.3. If applicable, within the next three (3) Business Days after deregistration or suspension of the Contracts referred to in Clauses 3.6.5.1 or 3.6.5.2, 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.

3.6.5.4. Where the Distribution Network Service Provider informs that the concerned Market Participant has remedied its default and the use of system agreement has been restored, the Market Operator shall lift the suspension from such Contracts on the date and time as informed by the concerned Distribution Network Service Provider.

### 3.6.6. ACTIONS TAKEN AFTER CONTRACT DEREGISTRATION OR SUSPENSION

3.6.6.1. 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.

3.6.6.2. Failure of a BPC to register a new Contract or to provide the requisite Security Cover and Guarantee Amount, pursuant to Clause 3.6.6.1.b), shall constitute an Event of Default and shall be dealt with under Sub-Section 16.2.1.

3.6.6.3. The BPC shall be liable to pay all applicable charges for the supply of electric power by the Supplier of Last Resort under Clause 3.6.6.1, with effect from the date of deregistration or suspension of the Contract.



- 3.6.6.4. Where a Generator, who is not a Market Participant and represented by another Market Participant is to be disconnected from the network due to default of its representative, the Market Operator shall inform the Generator to either become a Market Participant or appoint a new representative in the Market within a specified timeline. Failure to comply with such instructions by the Generator within the stipulated timelines, the Market Operator shall issue the disconnection request to the relevant network licensee for disconnection of the facility of such Generator.:
- 3.6.6.5. After deregistration of a Contract, the Market Operator shall update the Firm Capacity Register accordingly.
- 3.6.6.6. 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-assignment 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.
- 3.6.6.7. 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.
- 3.6.6.8. 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 Federal Government provide the revised Allocation Factors as per provisions of the National Electricity Plan, 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 18.2.9.





### 3.7.3. REGISTRATION OF LEGACY CONTRACTS-KE

- 3.7.3.1. KE shall register with the Market Operator all the Legacy Contracts-KE within one (01) month of the approval of this Code

### 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.

### 3.7.6. MERCHANT GENERATION

- 3.7.6.1. 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 its enrolment as Market Participant as per Sub-Section 2.3 above and execution of a Market Participation Agreement with the Market Operator.

- 3.7.6.2. Considering the techno-commercial impacts of ARE Generators, it is required that all the technical studies required for integration of such ARE Generators into the Grid System as per provisions of the Grid Code and Distribution Code shall be evaluated by the System Operator in accordance with the Grid Code irrespective of the connection voltage.

### 3.7.7. INTEGRATION OF CAPTIVE GENERATION INTO CTBCM FOR OPEN ACCESS FOR SELF-CONSUMPTION

- 3.7.7.1. A Captive Generator may avail open access for the purposes of carrying electricity from its Captive Generation Plant to the destination of its use, subject to its enrolment as Market Participant as per Sub-Section 2.3 above and execution of a Market Participation Agreement with the Market Operator. The Captive Generator will not be required to register any Contracts for self-consumption or give notice to the host SOLR under section 22 of the Act; however, it will register its Metering Points at the respective Connection Points (Captive Generation Plant and the destination of its use). The Captive Generator will be subject to the same requirements as any other Market Participant i.e. complying with Capacity Obligations, providing Security Covers and Settlement Guarantee Cover, participating in the balancing mechanisms and providing all the necessary information to the Market Operator as per provisions of this Code.



## 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 is of 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 Metering Service Providers shall be enrolled with the Market Operator as a Service Provider.

4.1.2.4. A Metering Service Provider authorised/permited 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.

## **4.2. 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. NGC, appointed as MSP under Clause 18.2.1.1, in coordination with K-Electric in its role as MSP, 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 NGC, in coordination with K-Electric, in accordance with Clause 4.2.1.3 above, and approved by the CCRP, shall be applicable on all Metering Service Providers.

Provided that till the time the CCOP referred above is prepared and approved by the CCRP, the MSP shall perform the meter reading and data collection as per the practice in vogue in accordance with the Grid Code or the Distribution Code, as the case may be, and shall comply with any specific instructions pertaining to meter reading and data collection issued by the Market Operator or the System Operator pursuant to the provisions of this Code.

- 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 (03) 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. STORAGE AND CUSTODY OF COMMERCIAL METERING DATA

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. COMMERCIAL METERING REPORT

4.5.1.1. Every year, a Metering Service Provider shall prepare, and submit to the Authority and 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. For purpose of clarification, the quantity registered in the Contract Register for a Merchant Generator or a Captive Generator availing opens access for self-consumption will be considered as zero.

#### 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

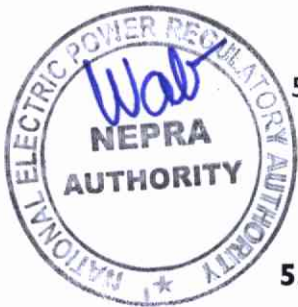
#### 5.2.1. CALCULATION OF GENERATION BY EACH GENERATION UNIT

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 Unit “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:

$$NetEnergy_{p,h}[MWh] = \sum_{\forall i \in Gen_p} E_{MPi,p,h}$$

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:

$$TotalGenU_{p,h} = NetEnergy_{p,h} \text{ if } NetEnergy_{p,h} > 0$$

$$TotalGenU_{p,h} = 0 \text{ in all other cases}$$

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:

$$GenU_{i,p,h} = TotalGenU_{p,h} * AC_{i,p,h} [MW] / \sum_{\forall i \in p} AC_{i,p,h}$$

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;
- $\forall i \in p$  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:

$$Gen_{p,h} (MWh) = \sum_{\forall i \in p} GenU_{i,p,h}$$

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.1 or Clause 5.2.1.1.b.3 above, as the case may be.
- $\forall i \in p$  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:

$$BFE_{p,h}[MWh] = \sum_{\forall i \in Gen_p} E_{MPi,p,h}$$

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:

$$BFE_{p,h}[MWh] = -NetEnergy_{p,h} \text{ if } NetEnergy_{p,h} < 0$$

$$BFE_{p,h}[MWh] = 0 \text{ in all other cases}$$

Where:

- $BFE_{p,h}$  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. CONSIDERATION OF DISTRIBUTION LOSSES

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) Export points located in the Distribution Network;
- c) a Generator receiving back-feed Energy which is not supplied by a Supplier of Last Resort; and
- d) a Captive Generator which is wheeling electric power from its Captive Generating Plant to the destination of its use;

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 or a Captive Generator, 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.

*It is clarified here that the Market Operator shall use the uniform distribution losses for all Distribution Licensees at each voltage level as determined by the Authority as per provisions of National Electricity Plan. This clarification applies to all the cases where the distribution loss factor is applicable under this Code.*



- b) For a Generator receiving Back-feed Energy which is not supplied by a Supplier of Last Resort, the adjustment shall be calculated as following;

$$Adj\_E_{p,d,h} = \sum_{\forall i \in p} BFFU_{i,p,h} / (1 - DistLoss_{d,q})$$

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 “q” to which the hour “h” belongs, as determined by the Authority for the relevant Distribution Licensee;
- $\forall i \in p$  means all Generation Units belong to Generator “p” connected to the Distribution Network.

- c) 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:

- Interconnection of the Transmission Licensee with a Generator
- Interconnection of the Transmission Licensee with another Transmission Licensee
- Interconnection of Transmission Licensee with Distribution Licensee
- Interconnection of the Transmission Licensee with the network of an entity from foreign countries of territories where the applicability of the Act is not extended
- Interconnection of a Transmission Licensee with a BPC.

5.4.1.4. Sign convention (I): 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:

- $\sum_k$  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:

$$Act\_E_{mp,h} = \sum_{i \in MP} Adj\_E_{i,h}$$

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 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 pursuant to Clause 5.3.1.4.b);

$\sum_{\forall BPC_i \in MP}$  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:

$$Act\_E_{mp,h} = \sum_{\forall p \in MP} Adj\_E_{p,d,h}$$

Where:

$Act\_E_{mp,h}$  is the total Energy withdrawn by Generator “mp” in hour “h”, in MWh;

$Adj\_E_{p,d,h}$  is 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, calculated pursuant to Clause 5.3.1.4.b);

$\sum_{\forall p \in MP}$  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 “p”, 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.b);

$\sum_{\forall i \in MP}$  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:

$$Act\_E_{mp,h}[MWh] = \sum_{\forall i \in mp} Adj\_E_{i,h} + \sum_{\forall j \in mp} EMP_{j,h} - \sum_{\forall k \in mp} Act\_E_{k,h}$$

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;

$\sum_{\forall i \in mp}$  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  $h$ ;
- $ETC_{mp,k,h}$  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:

$$\begin{aligned} Imb\_E_{mp,h}[MWh] &= Gen_{mp,h}[MWh] + Imp_{mp,h}[MWh] + ET_{mp,h}[MWh] \\ &\quad - ES_{mp,h}[MWh] \end{aligned}$$

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 withdrawn (or exported) by the Market Participant “mp” during hour “h”, calculated pursuant to Clause 5.4.5.1.

#### 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 as per the procedure included in Section 19.1 of this Code.
- 5.6.1.2. 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:

$$Bal\_Am_{mp,M}(PKR) = \sum_{h=1}^{Tot\_h} (Imb\_E_{mp,h}(MWh) * Marg_h(PKR/MWh))$$

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, RELIABILITY MUST RUN & 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 after first anniversary 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. 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.

6.2.1.7. Till the time the Authority approves the severely Congested Areas and Congested Zones, the following areas shall be considered as Congested Zones:

- a) The area served by K-Electric.
- b) The areas served by Ex-WAPDA DISCOs.
- c) The area served by QESCO which is not connected to the national grid.

## 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 by System Operator 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 compensation to be allocated to a Generator for its Generation Units which were considered as Transmission Must Run or Reliability Must Run:

$$MRC_{k,h}[PKR] = \sum_{j \in k} [UPC_{MR,j,h}[MWh] * (VC_{i,h} - Marg_h(PKR/MWh))]$$

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 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 a 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 6.4.1.1 above. 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 to the Market Operator, 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);
- $AC_{i,h}$  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;
- $EAG_{i,h}$  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:

$$AC_{k,h}[PKR] = \sum_{i \in k} [RG\_ASC_{i,h} * (Marg_h - VC_{i,h})] + \sum_{j \in k} [UPC\_ASC_{j,h} * (VC_{j,h} - Marg_h)]$$

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; |
| $VC_{j,h}$       | is the Variable Generation Cost of Generation Unit "j" during hour "h", communicated by the System Operator to the Market Operator, in PKR/MWh;          |
| $VC_{j,h}$       | 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 lower 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 as per provisions of the Grid Code.

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:

- 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
- 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.
- Any compensation related to the Legacy Contract -CPPA-G, Legacy Generators - DISCOs or Legacy Generators-KE shall be assigned to the respective Market Participants representing such contracts in the CTBCM.





## 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;



$Act_{EMP_{j,z,h}}$  is the Energy, withdrawn by Generator "j", 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:

$$ES_{CS_{k,z,m}}[MWh] = \sum_{h=1}^T Act_{EMP_{i,z,h}}$$

Where:

$ES_{CS_{k,z,m}}$  is the total Energy supplied by the Competitive Supplier "k", to its customers, located in the Congested Zone "z", during the Settlement Period "m", in MWh;

$Act_{EMP_{i,z,h}}$  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:

$$ES_{SLR_{l,z,m}}[MWh] = \sum_{h=1}^T Act_{EMP_{l,z,h}}$$

Where:

$ES_{SLR_{l,z,m}}$  is the total Energy supplied by the Supplier of Last Resort "l", to its consumers located in the Congested Zone "z", during the Settlement Period "m", in MWh;

$Act_{EMP_{l,z,h}}$  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:

$$ES_{Trader_{n,z,m}}[MWh] = \sum_{h=1}^T Act_{EMP_{n,z,h}}$$





Where:

$ES\_Trader_{n,z,m}$  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:

$$TotalEC_{z,m}[MWh] = TD_{z,m} + \sum_h \sum_{i \in z}^T Adj\_E_{i,z,h}$$

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 Participants, 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 "k" 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;

$TC_{Trader_{n,m}}$  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.

6.6.1.2. As per provisions of the Eligibility Criteria Rules (Electric Power Supplier License) 2023 (as amended from time to time), the distribution licensees shall collect the Market Operator fee from Market Participants connected to its network and deposit the same to the Market Operator as per the payment mechanism established with the Market Operator.



## 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 25<sup>th</sup> 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 fifteen (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 7.3.3, 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 ADVICE

### 7.4.1. ADVICE 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 two (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 ADVICE

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 payable or amount receivable that arises 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 Market Operator establishes the Designated Accounts mechanism with EX WAPDA DISCOs as per directions of the Authority, the amounts calculated pursuant to Clause 7.4.3.1 above and the Market Operator Fee shall be adjusted in the transfer pricing mechanism as set forth in the Agency Code and shall be settled accordingly.





## 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 (who is exempted from enrolment as Market Participant) 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:
- Temporary Firm Capacity Certificates
  - 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:
- Generation License or concurrence has been issued by the Authority or a formal application has been submitted in this respect, if required;
  - documents proving the acquisition or rental of the land for construction of the Generation Plant as well as the requisite transmission lines;
  - authorizations and permits, issued by the relevant entities, for the construction of the Generation Plant;
  - EPC contracts, clearly stating the project commissioning date; or
  - 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.
- Explanation:
- It is hereby clarified that a 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.
- 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, within one month of the CMOD, 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 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 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 before CMOD. 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 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 Legacy Contracts-CPPA-G registration mechanism given in Sub-Section 18.2.9 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. The Firm Capacity Certificates for Legacy Generators-DISCOs shall be deemed issued by the Market Operator to the respective EX-WAPDA DISCOs in their role as Supplier of Last Resort and this information shall only be provided to the EX-WAPDA DISCOs for demonstrating compliance with their Capacity Obligations.
- 8.3.2.6. After the CMOD, the Market Participant, who will procure Energy or Capacity through Import Contracts, the Initial Firm Capacity Certificates may be issued upon request of the concerned Market Participant.
- 8.3.2.7. 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.
- 8.3.2.8. After issuance of the Initial Firm Capacity Certificate, 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 issued, it may investigate the matter and if deemed appropriate, may take any action available under this Code or under the Applicable Law.
- 8.3.2.9. For a Generation Plant, the Initial Firm Capacity Certificates may be reduced or increased depending on its actual performance during System Peak Hours. This process may be initiated by the Market Operator on its own motion or upon the request of the concerned Market Participant.



8.3.2.10. For a Market Participant with Import Contracts, the Initial Firm Capacity Certificates may be reduced or increased 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 or upon the request of the concerned Market Participant.

8.3.2.11. 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. DETERMINATION OF INITIAL FIRM CAPACITY

### 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 actual Available Capacity of the Generation Plant during System Peak Hours 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 I below.



**Table 1: Equivalent Availability Factors**

| Sr. No.  | Generation Technology                                          | Equivalent Availability Factor |
|----------|----------------------------------------------------------------|--------------------------------|
| <b>1</b> | <b>Dispatchable Technologies</b>                               |                                |
| 1.1      | Hydro with reservoir                                           | 0.92                           |
| 1.2      | Thermal (either liquid fuels, gas, RLNG, or coal fired)        | 0.92                           |
| 1.3      | Bagasse                                                        | 0.92                           |
| 1.4      | Solar Thermal                                                  | 0.87                           |
| 1.5      | Nuclear                                                        | 0.87                           |
| <b>2</b> | <b>Non-dispatchable Technologies</b>                           |                                |
| 2.1      | Hydro run of river                                             | Based on the feasibility study |
| 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 or Legacy Generators-DISCOs or Legacy Generators-KE to be commissioned after the CMOD, the buyer in such Contract shall provide to the Market Operator, the information regarding the Dependable Capacity. 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 or the independent engineer, as the case may be, 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 shall 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, subject to approval of the CCRP.

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 shall 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 Generation Plant or 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 i.e. "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 Firm Capacity 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. After two iterations of the execution of the Balancing Mechanism for Capacity after CMOD, the System Operator shall, in collaboration with the Market Operator, make a CCOP by duly considering the results of these iteration, 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 Clause 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. The CCOP prepared under Clause 9.2.1.2 above shall also include a detailed methodology for implementing the calculations indicated in Clause 9.2.2.2. Such methodology shall take due consideration of:

- a) Generation Plants 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 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 a Market Participant 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 Market Participant 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 Market Participant 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:

$$ACC_{i,y}[MW] = \frac{\sum_{h \in CH} CC_{i,h}}{50 \text{ hours}}$$

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;





$h \in CH$  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:

$$ACR_{i,y}[MW] = \left[ \frac{\sum_{h \in CH} (ES_{i,h})}{50 \text{ hours}} \right] (1 + RM)$$

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;

$h \in CH$  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:

$$ACR_{j,y}[MW] = \frac{\sum_{h \in CH} \left( \sum_{\forall BPC_{i,j}} ES_{i,j,h} \right)}{50 \text{ hours}} (1 + RM)$$

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”;



$h \in CH$  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:

$$ACR_{k,y}[MW] = \frac{\sum_{h \in CH} (ES_{k,h})}{50 \text{ hours}} (1 + RM)$$

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;

$h \in CH$  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:

$$ACR_{k,y}[MW] = \frac{\sum_{h \in CH} (\sum_{\forall EXP_{x,k}} ES_{k,x,h})}{50 \text{ hours}} (1 + RM)$$

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";

$h \in CH$  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:

- $CB_{i,y}$  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:

- the efficient level of reserves required for the system; and
- 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:

- the investment costs;
- the operational costs;
- 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 and capped, for the purposes of this Code, to a maximum value of 20%:

$$RE = \frac{\sum_y \left( \frac{TIC_y}{PL_y} - 1 \right) * 100}{n}$$

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”, from the last 3 years of IGCEP, including transmission losses, which has been used by the System Operator in preparation of the IGCEP; |
| n       | is the number of last 3 years of IGCEP which shall be 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.

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 (12) 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 9.2.6.12.

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 Market Operator shall always use the latest values approved by the Authority.

#### 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.

- 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.
- 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 investment 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 investment cost of the reference technology, and the "efficient" demand level calculated as:

$$EDL_y = \sum_{vi \in neg} CB_{i,y} * \frac{1 + RE}{1 + RM}$$

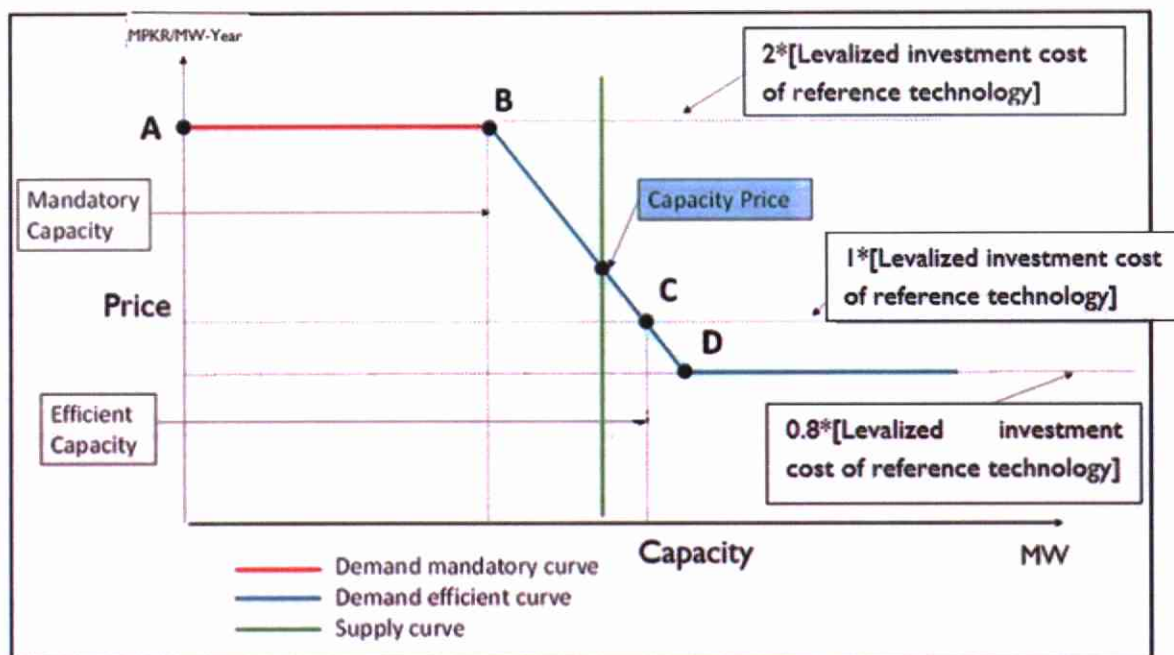
Where:

- *EDL* is the efficient demand level;
- *CB<sub>i,y</sub>* 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 investment costs of the reference technology. The Capacity prices will be capped at such level.

**Figure I: 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 I, 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";

$CB_{j,y}$  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";



$CB_{i,y}$  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;

$CB_{j,y}$  is the total amount of Capacity offered by the Market Participant "j", 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;
- $CP_{j,y}$  is the Capacity purchased by a Market Participant "i" in the settlement year "y" calculated pursuant to Clause 9.2.8.1;
- $CS_{i,y}$  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 "j" 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 "j" 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  $\#Block\_FCC_{CSj}$  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, a Captive Generator availing open access for self-consumption 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, especially for Suppliers of Last Resort, 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 30<sup>th</sup>) 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;
- d) For Captive Generator availing open access: Current year and following four (4) years; and
- e) 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 15<sup>th</sup>) 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 as per applicable documents and by taking into account the latest available information, including, 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 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 use the forecast submitted by the Supplier of Last Resort for calculation of the Capacity Obligations and highlight the differences in the Capacity Obligations report.

#### 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. DEMAND FORECAST OF CAPTIVE GENERATORS

10.3.6.1. A Captive Generator availing open access for self-consumption, shall submit to the Market Operator its demand forecast for all the periods for which it has availed open access or is planning to avail such open access.

#### 10.3.7. REVIEW OF THE DEMAND FORECASTS

10.3.7.1. 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.

10.3.7.2. 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 10.3.7.1, for verifying compliance with the Capacity Obligations.





10.3.7.3. 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.

10.3.7.4. 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:

$$CO_{BSi,p} = \frac{MD_{PH,i,p}}{(1 - Tloss_p)} * (1 + RM_p) * \frac{OB\%_{BS,p}}{100}.$$

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 Section 10.5;
- $MD_{PH,i,p}$  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:

$$MCO_{CSj,p} = \frac{MD_{PH,j,p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * \frac{OB\%_{CS,p}}{100}.$$

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;
- $MD_{PH,j,p}$  is the Maximum Demand at System Peak Hours of the Competitive Supplier "j" in the period "p". The value of  $MD_{PH,j,p}$  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;
- $Tloss_p$  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 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:

$$CO_{BPCk,p} = \frac{MD_{PH,k,p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * \frac{OB\%_{BPC,p}}{100}.$$

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:

$$CO_{Traderk,p} = \frac{MD_{PH,k,p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * \frac{OB\%_{Trader,p}}{100}.$$

Where:

- $CO_{Traderk,p}$  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;
- $OB\%_{Trader,p}$  is the Capacity Obligation Percentage, applicable to Trader involved in Firm Export, corresponding to period "p" as provided in Sub-Section 18.2.3;
- $Tloss_p$  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 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".

#### 10.4.5. CAPACITY OBLIGATIONS OF CAPTIVE GENERATORS

10.4.5.1. The Capacity Obligation of a Captive Generator availing open access for self-consumption, for each year in which this obligation is verified by the Market Operator, shall be calculated as:

$$CO_{CGk,p} = \frac{MD_{PH,k,p}}{(1 - Tloss_p - DistLoss_d)} * (1 + RM_p) * OB\%_{CG,p} / 100.$$

Where:

- $CO_{CGk,p}$  is the Capacity Obligation, of Captive Generator "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 Captive Generator availing open access for self-consumption "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 self-consumption, submitted by the relevant Captive Generator to the Market Operator, as per the requirements set out in Section 10.3, for the current year and all periods immediately thereafter;
- $OB\%_{CG,p}$  is the Capacity Obligation Percentage, applicable to Captive Generator availing open access for self-consumption, 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 self-consumption point of the Captive Generator is connected, as determined by the Authority for the relevant Distribution Licensee. In case any self-consumption point of the Captive Generator 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 31<sup>st</sup>, 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 Section 10.4. 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 misinterpretation, 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 30<sup>th</sup>, 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 10.3.1.1 above, 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 I 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. DISSEMINATION OF THE RESULTS AND ACTIONS IN CASE OF NON-COMPLIANCE**

### **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 16. 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 enrol 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, for the previous year, which may include, *inter alia*, the following:

- a) the Amounts Payable or Amounts Receivable by a Market Participant, as the case may be, for the participation in the Balancing Mechanism for Capacity;
- b) The Amounts Payable 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 or Amount 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 or System Operator or Market Operator 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 advice(s) 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 ADVICE

##### 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.



## 11.5. ASSESSMENT OF THE ANNUAL LOSSES OF A TRANSMISSION SERVICE PROVIDER

### 11.5.1. EXCESS LOSS CALCULATION

11.5.1.1. The Excess Losses shall be assessed and calculated by the Market Operator based on the information provided by the Commercial Metering System, according to the provisions of Chapter 4

11.5.1.2. The total Transmission losses of a Transmission Licensee shall be assessed by the Market Operator as:

$$TransLoss_k[MWh] = \sum_{h=1}^{h=n} \left( \sum_{\forall i \in MP_k} E_{MP_{i,k,h}} \right)$$

Where:

- $TransLoss_k$  are the total Transmission losses of the Transmission Service Provider "k" in the previous fiscal year, expressed in MWh;
- $E_{MP_{i,k,h}}$  is the Energy registered by the Commercial Metering System as per 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 boundary of the Transmission Service Provider "k";
- $\sum_{h=1}^{h=n} ( )$  means the sum over the total number of hours of the previous fiscal year (8,760 or 8,784 hours, as the case may be).

11.5.1.3. Sign convention: For the application of the formula provided in Clause 11.5.1.1, the Energy registered at each Metering Point at each particular hour shall be considered positive if it is injected into the Transmission Network of Transmission Service Provider "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.

### 11.5.2. CALCULATION OF TRANSMITTED ENERGY OF A TRANSMISSION SERVICE PROVIDER

11.5.2.1. The Market Operator shall calculate the total Transmitted Energy of a Transmission Service Provider, for the previous fiscal year, by adding the total Energy injected into the Transmission Network of the relevant Transmission Service Provider. For such purpose, the Market Operator shall utilize the metering data submitted by the Metering Service Provider as per provisions of Chapter 4.

11.5.2.2. Total Transmitted Energy, for the Transmission Service Provider shall be assessed as:

$$TransEnergy_k[MWh] = \sum_{h=1}^{h=n} \left( \sum_{\forall i \in MP_{G \rightarrow T}} E_{MP_{i,k,h}} \right)$$

Where:



- $TransEnergy_k$  is the total Transmitted Energy by the Transmission Service Provider “k”;
- $E_{MPi,k,h}$  is the Energy registered by the Commercial Metering System at the Metering Point “i”, corresponding to the Transmission Service Provider “k” in the hour “h”;
- $\forall i \in MP_{G \rightarrow T}$  means all those boundary points between a Transmission Network and
  - a Generator or Captive Generator; or
  - a Distribution Network; or
  - a BPC; or
  - an Import point; or
  - a Transmission Network of another Transmission Service Provider
 in which the Energy is injected into the Transmission Network of the Transmission Service Provider k (positive value according to the sign convention provided in Clause 11.5.1.3), during hour “h”;
- $\sum_{h=1}^{h=n} ( )$  means the sum over the total number of hours of the previous fiscal year (8,760 or 8,784 hours, as the case may be).

### 11.5.3. CALCULATION OF ANNUAL LOSSES PERCENTAGE OF A TRANSMISSION SERVICE PROVIDER

11.5.3.1. The Market Operator shall calculate the Annual Loss expressed in percentage of a Transmission Service Provider, for the previous fiscal year, by dividing the total Transmission losses by the Transmitted Energy of the relevant Transmission Service Provider.

$$AnnualLoss_k[\%] = \frac{TransLoss_k}{TransEnergy_k[MWh]} * 100$$

Where;

- $AnnualLoss_k$  is the Annual Loss expressed in percentage (%) of a Transmission Service provider “k” in the pervious fiscal year.
- $TransLoss_k$  are the total Transmission losses of the Transmission Service Provider “k” in the previous fiscal year, expressed in MWh;
- $TransEnergy_k$  is the total Transmitted Energy by the Transmission Service Provider “k”;



### 11.5.4. CALCULATION OF EXCESS LOSSES

11.5.4.1. In case the Transmission Service Provider’s Annual Loss Percentage is lower or equal to the allowed losses, as determined by the Authority in the latest Tariff Determination for the relevant Transmission Service Provider, the Excess Losses will be zero for such Transmission Service Provider. In other case, the quantum of excess losses (in MWh) shall be calculated as:

$$TSP \text{ Excess Losses } (MWh)_k = TransLoss_k[MWh] - AllowLoss(\%)_k * TransEnergy_k[MWh]$$

Where:

- $TSP \text{ Excess Losses}_k$  is the quantum of Excess Losses of the Transmission Service Provider k, expressed in MWh;

- $TransLoss_k$  are the total Transmission losses of the Transmission Service Provider  $k$  in the previous fiscal year, expressed in MWh, calculated pursuant to Clause 11.5.1.1;
- $AllowLoss_k$  is the allowed losses, expressed in percent, as determined by the Authority in the latest Tariff Determination of Transmission Service Provider  $k$ ;
- $TransEnergy_k$  is the total Transmitted Energy by the Transmission Service Provider  $k$  in the previous fiscal year, expressed in MWh, calculated as per Clause 11.5.2.2.

#### 11.5.5. SUBMISSION OF REPORT TO THE AUTHORITY

- 11.5.5.1. The Market Operator shall submit its assessment and calculations regarding Excess Losses of the Transmission Service Providers to the Authority within tow (2) months of completion of a fiscal year.





## 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 12.1.1.7;
- 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 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.

12.1.1.7. 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.

12.1.1.8. 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), having short term and long-term rating A and above, 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 OF EX-WAPDA DISCOS FOR MARKET SETTLEMENTS

12.1.3.1. The Market Operator shall establish the following mechanism with EX -WAPDA DISCOs for payment purposes within a period as directed by the Authority. Till such time this mechanism is established, any amount that arise due to Settlement of Legacy Contracts-CPPA-G, signed or administered by the CPPA-G 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 for transition period as provided in the Agency Code Following the transition period, the Market Operator Fee shall be directly collected by the MO from the Ex-WAPDA DISCOs. During this period, the Market Operator shall issue the Debit Advice on the date of issuance of the Final Settlement Statement to the SPA for





any amount to be paid by it on behalf of Ex-WAPDA DISCOs and KE and the SPA shall pay the amount on the same date in order to ensure the integrity of the CTBCM.

- 12.1.3.2. Each EX-WAPDA DISCO in its 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 EX-WAPDA 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 EX-WAPDA DISCO 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 EX-WAPDA DISCO for disbursement of payments to the Market Operator and the EX-WAPDA DISCO. Such standing instructions may be reviewed on periodic basis by the Market Operator and the relevant EX-WAPDA DISCO 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 EX-WAPDA DISCO to the Market Operator settlement accounts on receipt of instructions from the Market Operator and the relevant EX-WAPDA DISCO 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 Market Operator Fee and System Operator Fee. (if applicable).
  - b) when funds remain in the Designated Account after payment of amounts on account of Market Operator Fee and System Operator Fee (if applicable) under Clause 12.1.3.6.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;
  - c) when funds remain in the Designated Account after payment of amounts on account of Settlement Guarantee Cover under Clause 12.1.3.6.b) 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;
  - d) 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.c) 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;





- e) 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.d) 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; and
- f) 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.e) above, the Designated Bank shall act in accordance with the instructions of the relevant EX-WAPDA DISCO.

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 EX-WAPDA 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 EX-WAPDA DISCO and the EX-WAPDA DISCO 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. MARKET OPERATOR PAYMENTS CALENDAR**

### **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 1<sup>st</sup> 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 25<sup>th</sup> 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 five (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. PAYMENT PROCEDURES

### 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 Advice(s) 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 Advice(s) in full;

- b) where the total funds available in respect of Security Cover for monthly Settlement, in the Market Operator Security Cover Account, pertaining to all Market Participants, are not sufficient to make full payments to the Market Participants under the Credit Advice, 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 except for the Debit Advice to be issued to SPA as per Clause 12.1.3.1, 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 Advice 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 Market Operator Security Cover Account, pertaining to all Market Participants are deficient to make full payment to the Market Participants under the Credit Advice(s), 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 Advice(s) 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 Advice(s), 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 Advice(s) 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. 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 and SO Fee (if applicable), 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.
- 13.1.1.7. For the period as mentioned in Clause 12.1.3.1, Clause 13.1.1.1 and Clause 13.1.1.4 shall not be applicable for the Ex-WAPDA DISCOs and KE to the extent of payments arising on account of administration of Legacy Contracts-CPPA-G.

#### **13.1.2. ACCEPTABLE FORM OF SECURITY COVERS, GUARANTEE AMOUNT AND ADVANCE INSTALMENT**

- 13.1.2.1. The Security Covers, Settlement Guarantee Cover and Advance Instalment shall, as default, be in the form of cash. If mutually agreed between the Market Operator and the Market Participant, other financial instruments may also be adopted as a mode of security.

#### **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. The CCOP shall be based on the following principles:



- a) The amount shall be based on an estimation of the potential payment that the parties to the Contract shall make for the purchase of Energy in the Balancing Mechanism for Energy, Ancillary Services and Transmission Must Run and Reliability Must Run compensation costs, the Market Operator and System Operator fee (if applicable), for one (1) Energy Settlement Period.
- b) The estimation shall duly consider the estimated dispatch of the Generation Plants and their maintenance schedules.
- c) The estimations shall be done for a period of six months from the effective date of the Contract and the maximum value for a month shall be considered for the initial amount of Security Cover.

13.1.3.2. Till the time, the CCOP is prepared as per Clause 13.1.3.1 above, 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.;
- 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 when submitted in 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. For other forms of securities, the Market Operator shall ensure that all documents provided as financial security are maintained in a secure, traceable, and readily accessible manner, and safeguarded against loss, damage, or unauthorized access.

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 when submitted in form of cash. For other forms of securities, the Market Operator shall ensure that all documents provided as financial security are maintained in a secure, traceable, and readily accessible manner, and safeguarded against loss, damage, or unauthorized access. Till the time, the CCOP is prepared as per Clause 13.1.3.1, above, 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 its 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, , 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 within 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, 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 average Marginal Price for the last month (PKR/kWh) from the date of calculation;
- c) for enrolment as a Captive Generator, the amount of the Security Cover shall be determined on the basis of its expected Imbalance calculated as per the CCOP for Security Cover; and
- d) 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. ADVANCE INSTALMENT FOR YEARLY SETTLEMENTS

#### 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:
- the identification of each Market Participant;
  - 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 Cover 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 13.4.2.1, 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 for information. The report may include steps being taken or to be taken by the Market Operator 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 Provider 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) if applicable, 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. PAYMENTS & RECOVERY OF MONETARY AMOUNTS

14.2.1.1. Where a Dispute involves the payment or recovery of monetary amounts due under this Code, the amount shall be due and payable at the time specified for payment. Notwithstanding, initiation of a dispute resolution process shall not hamper the payment or recovery of monetary amounts under this Code or otherwise.



### **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. 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.
- 14.3.2.3. 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. After hearing the parties, the Sole Expert shall communicate its decision in writing to the parties.

14.3.3.6. If any party to the Dispute does not agree with the decision 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 and will present its finding to the Authority.

#### **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. The plan shall be submitted as part of the Market Operator Fee petition.

#### **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 and to also provide input during the preparation of the integrated energy plan as per the relevant regulations
- 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 impact 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, within six (06) months of the CMOD:
- 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 or as directed by the Authority from time to time.
- 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 shall prepare a report for the Authority at least once a year, which will include the Market Operator's overall assessment as to the state of competition within, and the efficiency of, the CTBCM and proposed measures or steps required to address any market design issues or anti-competitive practices in the Market
- 15.2.3.9. 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.
- 15.2.3.10. 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;



## Chapter 16. ENFORCEMENT OF COMMERCIAL CODE

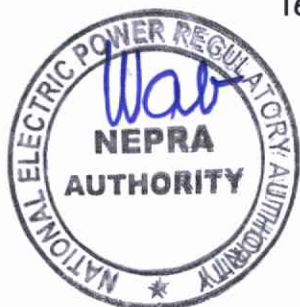
### 16.1. COMPLIANCE AND BREACHES

#### 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 ensure compliance with the provisions of this Code 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 non-compliance to 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 remedial actions in respect of a breach of a particular Clause or provision by a Market Participant or Service Provider, those consequences or remedial actions shall apply in the circumstances and in the manner provided for in the relevant Clauses or provisions, in addition to any other remedial actions 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.





15.2.3.11. if the report prepared pursuant to Clause 15.2.3.10 above, 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. SUPPORT OF INDEPENDENT MARKET ASSESSMENT

15.2.4.1. The ISMO shall facilitate and provide all required information for the independent evaluation of the CTBCM by the Authority.

15.2.4.2. The Market Operator shall submit the catalogue of monitoring indicators referred to in Clause 15.2.3.2.b) to the Authority for approval, prior to utilizing it for the analysis and evaluation of the collected data and its subsequent publication on the ISMO website.

15.2.4.3. At the direction of, and according to the specifications provided by the Authority, the Market Operator, in consultation with the System Operator, shall establish a system for the collection, classification, and dissemination of data from ISMO data warehouse and file management system to the NEPRA. This information shall include, but not limited to:

- a) information related to the Contracts and the quantities traded in each Contract;
- b) information related to quantum traded through BME and BMC
- c) information related to Transmission Must Run, Reliability Must Run and Ancillary Services;
- d) information related to prices used in the BME and BMC.

#### 15.2.5. DISPUTE RESOLUTION AND OTHER RELIEF

15.2.5.1. The dispute resolution procedures under Chapter 14 shall not apply to the activities carried out by the Market Operator under this Chapter.

#### 15.2.6. PUBLICATION AND PROVISION OF DATA

15.2.6.1. 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.



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. SUSPENSION AND TERMINATION ORDERS**

### **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;
- 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 is established by the Market Operator under the market assessment that the Market Participant is involved in anti-competitive behaviour and has manipulated the market as per Clause 15.2.1.1.a);
- e) 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;

- f) 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;
- g) the Authority publishes a notice to this context, or if it comes into the information of the Market Operator, that procedures have been initiated that it may revoke the License of the Market Participant;
- h) 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;
- i) the Market Participant states that it is unable to pay from its own money its debts when they fall due for payment;
- j) 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;
- k) 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;
- l) 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;
- m) the Market Participant is wound up or dissolved, unless the notice of winding up or dissolution is discharged;
- n) the Market Participant is taken to be insolvent or unable to pay its debts under any applicable legislation;
- o) the Market Participant ceases to satisfy any material requirement imposed upon it as a condition of its enrolment to participate in the CTBCM;
- p) 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;
- q) the Market Participant persistently commits breach of this Code; or
- r) 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.

#### 16.2.2. ACTIONS BY MARKET OPERATOR IN THE EVENT OF DEFAULT

16.2.2.1. 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 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.

16.2.2.2. The Market Operator shall duly consider the timelines required for disconnection by a network licensee under the applicable documents while issuing a disconnection request under this Code.

16.2.2.3. For issuance of the Suspension Order and request for temporary or permanent disconnection pursuant to Clause 16.2.2.1.c), the provisions of Sub-Section 16.2.3 shall, not apply.

16.2.2.4. 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.

16.2.2.5. 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.

16.2.2.6. 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.e) and 16.2.1.1.h) to 16.2.1.1.n), 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.

16.2.2.7. 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.





16.2.2.8. The Market Operator may issue the non-compliance letters or take any remedial actions as provided in Sub-Section 16.3 before issuance of the Suspension Orders as provided below.

#### 16.2.3. SUSPENSION ORDERS

16.2.3.1. 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.

16.2.3.2. The Market Operator shall provide a copy of the notice issued pursuant to Clause 16.2.3.1 to the relevant Transmission or Distribution Network Service Provider.

16.2.3.3. Upon receipt of the notice issued pursuant to Clause 16.2.3.1, 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 Suspension Order, the request for disconnect, or both, as the case may be, shall not be issued.

16.2.3.4. Where the Market Participant:

- a) has not requested a meeting pursuant to Clause 16.2.3.3, 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.

16.2.3.5. Where the Market Participant has requested a meeting pursuant to Clause 16.2.3.3, 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.



16.2.3.6. 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.

16.2.3.7. 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.

16.2.3.8. Upon receipt of the disconnection request from the Market Operator, the System Operator shall issue instructions to desynchronize the facilities or equipment of the 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 16.2.3.10 and shall synchronize or reconnect such facilities or equipment on the date and at the time specified in such notice.

16.2.3.9. 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 16.2.3.11, 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.

16.2.3.10. 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 System Operator (if applicable), the Transmission or Distribution Network Service Provider, as the case may be, accordingly.





- 16.2.3.11. 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, or modified and publish the same on the MO Website.
- 16.2.3.12. 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.
- 16.2.3.13. 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.
- 16.2.3.14. 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, prior to the date on which the Suspension Order was issued.

#### 16.2.4. REVOCATION OF ENROLMENT AND TERMINATION OF MARKET PARTICIPATION AGREEMENT

- 16.2.4.1. 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:
- 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
  - has informed the Market Operator that it is not likely to remedy such Event of Default.
- 16.2.4.2. 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.
- 16.2.4.3. 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 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.

16.2.4.4. The Market Operator shall provide a copy of the notice issued pursuant to Clause 16.2.4.3 to the Authority and the relevant Transmission or Distribution Network Service Provider.

16.2.4.5. Upon receipt of the notice issued pursuant to Clause 16.2.4.3, 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.

16.2.4.6. Where the Market Participant:

- a) has not requested a meeting pursuant to Clause 16.2.4.5, 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.

16.2.4.7. Where the Market Participant has requested a meeting pursuant to Clause 16.2.4.5, 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 request or both should not be issued against it. In such circumstances, the Market Operator shall not issue either the Termination Order, the disconnection request or any other order until such meeting has been held.

16.2.4.8. 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.

16.2.4.9. The System Operator shall comply with the provisions of the Grid Code while implementing such disconnection request from the Market Operator issued under this Code.





16.2.4.10. 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.

16.2.4.11. 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.

16.2.4.12. 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.

16.2.4.13. 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.

16.2.4.14. 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 propose 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 remedial action 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 increase the level of non-compliance for 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 as well as in line with the applicable data protection laws of the country.

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 for 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 as per the Applicable Laws.

### **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, or as the Applicable Laws.

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. In the event, a person knowingly discloses a sensitive information or makes a misleading or deceptive statement shall be penalized as per the Applicable Laws.

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 a written application by a person, the Market Operator may disclose the Non-Confidential Information which is not available on MO Website on such terms and conditions as 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.

Provided that the Market Operator shall also publish such information on MO Website as may be required or directed by the Authority from time to time.

17.3.1.4. The following information and documents shall be published on the ISMO 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 Hourly System Marginal Price, and forecast of future (1 year horizon) System Marginal Price;
- k) the results of the Balancing Mechanism for Energy and Capacity;
- l) the results of the verification compliance with the Capacity Obligations;
- m) the Capacity Certificates issued for each Generator;
- n) volumes of electricity (both capacity and energy) traded in the market on a daily, monthly, and annual basis.
- o) comparison of market contracts volumes versus Legacy Contracts volumes to indicate market liquidity and competitiveness.
- p) 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.

#### 17.3.4. APPLICABLE DATA PROTECTION LAWS

17.3.4.1. The handling, access, disclosure, and processing of any information or retention of record required under this Code or CCOPs shall be governed by the applicable data protection laws of the country.





## Chapter 18. MISCELLANEOUS, COMPLEMENTARY AND TRANSITORY PROVISIONS

### 18.1. COMPLEMENTARY 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 Grid 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. 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.

18.2.2.4. 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 qualifiers of the meter readings if the Meter produces such kind of information.

18.2.2.5. 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.

18.2.2.6. 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 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.
- e) For Captive Generators availing open access for self-consumption, the values provided in Table 7 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 <sup>(1)</sup> | 100                                                                        |
| Ex-ante compliance with the Capacity Obligations | Current year <sup>(2)</sup>  | 100                                                                        |
|                                                  | Year 1 <sup>(3)</sup>        | 100                                                                        |
|                                                  | Year 2                       | 100                                                                        |
|                                                  | Year 3                       | 80                                                                         |
|                                                  | Year 4                       | 60                                                                         |

- (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 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 <sup>(1)</sup> | 100                                                                        |
| Ex-ante compliance with the Capacity Obligations | Current year <sup>(2)</sup>  | 100                                                                        |
|                                                  | Year 1 <sup>(3)</sup>        | 100                                                                        |
|                                                  | Year 2                       | 100                                                                        |
|                                                  | Year 3                       | 80                                                                         |
|                                                  | Year 4                       | 60                                                                         |

- (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 <sup>(1)</sup> | 100                                                                               |
| Ex-ante compliance with the Capacity Obligations | Current year <sup>(2)</sup>  | 100                                                                               |
|                                                  | Year 1 <sup>(3)</sup>        | 100                                                                               |
|                                                  | Year 2                       | 100                                                                               |
|                                                  | Year 3                       | 80                                                                                |
|                                                  | Year 4                       | 60                                                                                |

- (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 <sup>(1)</sup> | 100                                                                               |
| Ex-ante compliance with the Capacity Obligations | Current year <sup>(2)</sup>  | 100                                                                               |
|                                                  | Year 1 <sup>(3)</sup>        | 100                                                                               |
|                                                  | Year 2                       | 100                                                                               |
|                                                  | Year 3                       | 80                                                                                |
|                                                  | Year 4                       | 60                                                                                |

- (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 7: Capacity Obligations for Captive Generators opting for open access for self-consumption**

| 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 <sup>(1)</sup> | 100                                                                               |
| Ex-ante compliance with the Capacity Obligations | Current year <sup>(2)</sup>  | 100                                                                               |
|                                                  | Year 1 <sup>(3)</sup>        | 100                                                                               |
|                                                  | Year 2                       | 100                                                                               |
|                                                  | Year 3                       | 80                                                                                |
|                                                  | Year 4                       | 60                                                                                |

- (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.



#### 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.

18.2.4.2. The National Electricity Plan states that the electric power from the power pool of legacy contracts, i.e., contracts executed prior to the CMOD, shall be allocated to each Supplier of Last Resort, except K-Electric, based on their share in the coincidental system peak demand, provided that for such computations:

- a) fifty (50) hours in which the demand served at overall system level was highest shall be taken into consideration;
- b) no more than five (5) hours of the same day shall be included; and
- c) company wise share shall be determined as an average of last three (3) years or as deemed appropriate.

18.2.4.3. As per provisions of the National Electricity Plan, till the time the MoE (PD) determines that Allocation Factors, the Market Operator shall determine the allocation factors as follows:

- a) for each Ex-WAPDA DISCO, except PESCO and TESCO, as per the mechanism provided in Clause 18.2.4.2 above;
- b) for PESCO and TESCO, a combined Allocation Factor shall be established first as per the mechanism provided in Clause 18.2.4.2 above.
- c) the individual Allocation Factor for PESCO and TESCO shall be established based on average share in capacity payments for past three years (2023, 2024 and 2025), provided that upon installation of Commercial Metering System at all Metering Points between PESCO and TESCO and collection of sufficient data (at least for System Peak Hours for one (1) year), the mechanism provided in Clause 18.2.4.2 above shall be utilized for re-calculation of the allocation factors for PESCO and TESCO; and
- d) the KE shall be assigned its share as per the terms and conditions of its PPAA/SPAA with SPA.

18.2.4.4. 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. The Allocation Factors calculated by the Market Operator shall be used by the Special Purpose Agent for calculation of capacity charges for demand participants in accordance with the provisions of the Agency Code.

#### 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 18.2.4.4.

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-WAPDA 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 per the applicable laws 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, the unitary cost of Capacity shall be equal to (10,500,000) PKR/MW/year.

#### 18.2.8. TRANSITION TOWARDS GUARANTEE BASED MECHANISM

18.2.8.1. 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 completely 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.

#### 18.2.9. REGISTRATION OF LEGACY CONTRACTS-CPPA-G

18.2.9.1. 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. Subject to Clause 12.1.3.1, any payment arising on account of this entity shall be proportionally allocated to the EX WAPDA DISCOs and KE based on their share in the Legacy Contracts-CPPAG;
- 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 18.2.4.4 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 SPA and KE in the PPAA/SPAA or any other arrangement in place;
  - c.3. for each EX-WAPDA DISCO, 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:

$$AE_h (MWh) = AEG(vre) + AEG(Hydro_{run\ of\ river}) + AEG(test\ run) + AEG(others) + AC(hydro_{storage}) + AC(thermal) - EU_{KE}$$

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 5.2.2.1 above;





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 5.2.2.1 above;

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<sub>KE</sub> 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<sub>ih</sub> is the Cap on the contracted Energy between "Legacy Generators" and the EX-WAPDA DISCO "i" in hour "h";

AE<sub>h</sub> is the available Energy of the Legacy Generators in the hour "h" to be allocated among the EX-WAPDA DISCOs, calculated pursuant to Clause 18.2.9.1.c.4 above;

AF<sub>i</sub> is the Allocation Factor of EX-WAPDA DISCO "i" published by the Market Operator as per Clause 18.2.4.4 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, the System Operator license and other relevant regulations require 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. It is the responsibility of the System Operator to be equipped with state-of-the-art software and IT systems, and develop or modify the operational procedures to ensure that the System Operations are transparent, auditable and carried out in the most economical way in accordance with the provisions of the Grid Code. The System Operator shall, on an ongoing basis, equip itself and develop its capacity to perform the system operations in the most economical manner in accordance with the Grid Code.
- 19.1.1.4. In accordance with the Security Constrained Economic Dispatch carried out by the System Operator, 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.
- 19.1.1.5. The System Operator shall keep the record of SCED for at least three years in a secured manner and provide the same to the Authority or Market Operator in case of any dispute or any other matter related to this code or as directed by the Authority from time to time.

#### 19.1.2. PROCEDURE FOR DETERMINING THE SYSTEM MARGINAL PRICES

- 19.1.2.1. Each 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, however, it shall be expressly understood that assigning any operational label will not qualify any Generation Plant for any compensation except as specified in this Code:
- 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 because such plants are not included in the merit order list and are considered as having no fuel cost;
  - 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, document and publish 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-sync 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 I  | 0                        | 175.0              | 175.0                         | Zero Fuel Cost    |         |
| 2  | Mangla                     | Unit I  | 0                        | 100.0              | 100.0                         | Zero Fuel Cost    |         |
| 3  | Ghazi Barotha              | Unit I  | 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 I  | 0                        | 175.0              | 175.0                         | Zero Fuel Cost    |         |
| 2  | Mangla                                   | Unit I  | 0                        | 100.0              | 100.0                         | Zero Fuel Cost    |         |
| 3  | Ghazi Barotha                            | Unit I  | 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               |                 |

### 19.1.3. 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:

- 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;
- 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 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           |                 |







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