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TA-9672 PAK: Developing Electricity Market in Pakistan (52323-001)

CTBCM DETAIL DESIGN REPORT

Prepared for	ASIAN DEVELOPMENT BANK
Beneficiary	CENTRAL POWER PURCHASING AGENCY

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*"**Individually**, we are one drop. **Together**, we are an **ocean**."*

(Ryunosuke Satoro)

*“**Together,** reforming the Sector, improving the **lives**”*

(Team Power Sector)

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Acronyms

AEDB	Alternate Energy Development Board
BMC	Balancing mechanism for Capacity
BME	Balancing mechanism for Energy
BPC	Bulk Power Consumer
BST	Bulk Supply Tariff
CCRP	Commercial Code Review Panel
CDP	Common Delivery Points
COD	Commercial operation date
CPPA-G	Central Power Purchasing Agency (Guarantee) Limited
CREPA	Contract Registrar and Power Exchange Administrator
CTBCM	Competitive Trading Bilateral Contract Market (competitive wholesale electricity market for Pakistan)
DISCOs	Distribution Companies; successors of WAPDA restructuring
ECC	Economic Coordination Committee
EPA	Energy Purchase Agreement
ETR/CTR	Energy Transfer Rate/Capacity Transfer Rate
GENCOs	Government owned thermal Generation companies, successors of WAPDA restructuring
IAA	Independent Auction Administrator
IEMSM	Integrated Electricity Market Simulation Model
IGCEP	Indicative Generation Expansion Capacity Plan
KE	K-Electric, formally known as KESC.
KESC	Karachi Electric Supply Company (K-Electric)
MO	Market Operator
MoF	Market Operator Fee
NEPRA	National Electric Power Regulatory Authority
NPCC	National Power Control Centre
NTDC	National Transmission and Dispatch Company
PPA	Power Purchase Agreement
PPAA	Power Procurement Agency Agreement
PPIB	Private Power Infrastructure Board
SB	Single buyer

SBP	Single buyer plus
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
SDC	Scheduling and Dispatch Code
SPT	Special Purpose Trader
TNO	Transmission Network Owner
UoSC	Use of System Charge
VIU	Vertical Integrated Utility
WAPDA	Water and Power Development Authority
WPPO	WAPDA Private Power Organization

Detailed Design of Competitive Wholesale Market (CTBCM)

1. BACKGROUND

1.1. BRIEF HISTORY OF POWER SECTOR AND MARKET DEVELOPMENT

The power sector of Pakistan is one of the most capital-intensive sectors of the country and is considered as the backbone of the economy. At the time of independence in 1947 Pakistan had installed power generating capacity of 60MW. The Water and Power Development Authority (WAPDA) was established as an Integrated Utility in 1959 with the massive agenda of development in generation, transmission and distribution of power along with irrigation, drainage and flood control etc. At this time, the sector was managed by two public sector vertically integrated utilities, WAPDA and KESC. KESC has started its work in 1913 as privately-owned company to supply electricity to the city of Karachi and its suburbs. After independence, the government of Pakistan took control of KESC in 1952 and had been operating in this manner till it was privatized in 2006.

As per its mandate, WAPDA undertook various initiatives to expand generation, transmission as well as distribution system during the next decades by building major hydel projects such as Tarbela and Mangla along with other thermal generation. By 1991, the power generation capacity reached to around 7000 MW.

In 1992, WAPDA Strategic Restructuring Plan was approved by Government of Pakistan for the privatization of power sector with the following goals:

i. Enhance capital formation,
ii. Improve efficiency and reconcile the prices.
iii. Introduction of competition to the power sector with the passage of time, by providing the greatest possible role through privatization

One of the major tasks of the Restructuring Plan of WAPDA was to establish an independent regulatory authority to overlook the restructuring process and to regulate the de-bundled entities as these will be monopolistic services in their respective jurisdiction. Th National Electric Power Regulatory Authority (NEPRA) was established as Independent Regulatory of the power sector in 1997 through enactment of the Generation, Transmission and Distribution of Electric Power Act, 1997 (NEPRA Act.) Subsequently, the de-bundling of WAPDA into generation, transmission and distribution entities was completed in 2000. As a result, thermal generation was assigned to GENCOs (4 no.), National Transmission and Despatch Company was established to take over high voltage transmission network (500 kV and 220 kV), and eight distribution companies (further de-bundled into 10 later) were established to perform the distribution function and sale of electric power to consumers[1].

In 2002, NTDC was given a license in which NTDC was assigned the following four functions.

1. Power Procurement to act as single buyer and procure power on behalf of DISCOs
2. System Operation and Dispatch for the safe and reliable operation, control, switching and dispatch of transmission system and the generation facilities and provision of balancing services

[1] https://www.diva-portal.org/smash/get/diva2:917526/FULLTEXT01.pdf

3. Transmission Network Operator for the operation and maintenance (O&M) of the transmission system including planning, design and capacity expansion of its transmission system, generation expansion, least cost planning, and siting of new generation facilities
4. Contract Registrar and Power Exchange Administrator (CRPEA) for the recording and notification of the contracts and other matters relating to bilateral trading between the generation licensees and BPCs, and between the generation licensees and the Distribution Companies for the future capacity needs. The CRPEA will also handle a financial settlement system in close coordination with the System Operator for the Balancing Market and for the differences arising with CPPA.

In its license, NEPRA directed NTDC to prepare a plan to transition from the Single Buyer (SB) model to Single Buyer Plus (SBP) model by 2004 and towards a Competitive Trading Bilateral Contract Market (CTBCM) by July 2009. Due to different reasons, this plan was never developed and the CTBCM couldn't be implemented as per the stipulated time.

CPPA being a function of NTDC earlier, was legally separated in 2009 and started its independent operations in 2015. During the same year, the Economic Coordination Committee (ECC) of the Cabinet decided to transition from the current regime towards CTBCM and mandated CPPA-G to prepare a design and plan for this transition and get it approved from NEPRA. The summary of the ECC decision is as under.

ECC Decision ECC-78/9/2015 (April 30, 2015) on Pakistan Power Sector Reform - CPPA-G

> "*The Economic Coordination Committee of the Cabinet Considered the Summary dated 30th April 2015 submitted by the Ministry of Water and Power regarding Pakistan Power Sector Reform-CPPA A-G" and approved the proposals contained in Para-11 read with Para 6, 7, 8 and 9 of the Summary*."

Paragraph 9 of the ECC Summary establishes the mandate and timeline for CPPA G to prepare (by 2018) the plan with the design, transition and implementation of the competitive wholesale electricity market – the Competitive Trading Bilateral Contract Market (CTBCM) – to start by 2020:

> "*9. Within two (02) years of the notification of Market Rules and associated operationalization of CPPA-G, CPPA-G shall prepare a comprehensive Competitive Trading Bilateral Contract Market (CTBCM) Plan for transition of the power market to a Competitive Trading Bilateral Contract Market. This plan, to be prepared in consultation with stakeholders and subsequently approved by NEPRA, will outline the actions that ought to be taken and completed at the end of each phase of the transition to a fully competitive wholesale electric power market. The actions that shall be taken within three to four (3-4) years for implementation, from the date of the approval of the CTBCM Plan, will consist of regulatory, legal, technical, commercial and financial actions that will set the groundwork for the transition to the wholesale power market by 2020*."

Subsequent to this decision, NEPRA issued Market Operator Registration, Standards and Procedure Rules, 2015 (Market Operator Rules, 2015) and CPPA-G was registered as Market Operator and was assigned the following functions.

i. To procure power as an agent of the DISCOs
ii. To act as Market Operator to facilitate the transition from the regime towards CTBCM

In pursuance of the mandate given by ECC and the stipulations of the Market Operator Rules, 2015, CPPA-G with the help of international consultants (MRC Group) prepared a high-level conceptual design, defining the principles and structure of the market, and submitted it to NEPRA for approval in March 2018.

NEPRA published the model on its website seeking comments from the stakeholders and general public. As a result, many comments were received which were addressed by CPPA-G within due time. Meanwhile, CPPA- G requested Ministry of Energy (Power Division) to move a summary to the ECC requesting an extension in the timelines which was granted. The summary of the decision is reproduced below:

> *"The Economic Coordination Committee (ECC) of the Cabinet considered the summary dated 22nd October 2019, submitted by the Power Division regarding Approval for Extension in Commercial Operation Date (COD) of the Competitive Trading Bilateral Contract Market (CTBCM) and decided as under:*
>
> *i)* *Approval extension in timeline for commencement of Competitive Market Operations / Commercial Operation Date of the Competitive Trading Bilateral Contract Market (CTBCM) for completion of CTBCM Plan within 18 months after approval of CTBCM by NEPRA.*
>
> ii) *Allowed NEPRA to amend the timelines of market transition towards a Competitive Market operation / CTBCM operations mentioned in Schedule-I of the National Electric Power Regulatory Authority (Market Operator Registration, Standards and Procedure) Rules, 2015*."

Para 8 of the Summary dated 22nd October 2019 are as under:

> *i)* *"Timeline for commencement of Competitive Market Operations /commercial operation date of the Competitive Trading Bilateral Contracts Market (CTBCM) may be extended to allow completion of CTBCM Plan within 18 months after approval of CTBCM Plan by NEPRA. The approval of CTBCM model and Plan is anticipated by December 2019.*
>
> ii) *Based on the above NEPRA may be allowed to amend the timelines of market transition towards a Competitive Market operations /CTBCM operations mentioned in Schedule-I of the National Electric Power Regulatory Authority (Market Operator Registration, Standards and Procedure) Rules, 2015."*

After thorough deliberations at NEPRA, the CTBCM conceptual design and implementation road map submitted by CPPA-G was approved with specific actions to be taken by the Market Operator and other entities in the short term as well as long term in order to ensure the commencement of the wholesale electricity market (CTBCM) on the stipulated times.

1.2. PURPOSE OF THE REPORT

For the development of the design of the market and its implementation, CPPA-G adopted a phased wise approach. In the first phase, a high-level conceptual design of the market was prepared and submitted for regulatory approval. the conceptual design report was followed by a detailed design of the market providing further understanding and working out details of the concepts presented in the high-level conceptual design report.

In its determination, NEPRA also directed CPPA-G to submit an updated detailed design within 60 days from the date of receipt of determination. Point (a) of the decision of Authority states that:

"(a). Submission of Updated and Detailed Design and Implementation Roadmap

Within sixty (60) days of the issuance of this determination, the CPPA-G, after consultation with the market participants, service providers, and other relevant stakeholders, will submit an updated and detailed design of the CTBCM Model and its Implementation Roadmap, along with specific timelines, for approval of the Authority. The detailed design and Implementation Roadmap will include, inter-alia, the types and designs of new market contracts, mechanism for treatment of existing contracts, plan for the bifurcation of CPPA-G into Market Operator and SPT, mechanism for establishment of a Balancing Mechanism, IT interventions required for the commencement of the Market Operations, listing of detailed design actions/reports and timelines for their completion for approval of the Authority, and actions to be completed by stakeholders especially service providers. CPPA-G shall also submit an updated version of Integrated Electricity Market Simulation Model (IE-MSM) Report and Detail Design Report within two months of this determination."

Pursuance of the strategy and in compliance with the directions of NEPRA, this report has been prepared to work out the details of the concepts introduced in the approved high-level conceptual design and to address all the aspects as mentioned in the determination of NEPRA.

1.3. STRUCTURE OF THE REPORT

The report is organized in several sections and as such first few sections of the report provides an overview of different elements of the markets with further details provided in subsequent sections. All concepts are explained in adequate details to understand the design of the market. The report also identifies different polices, rules and regulation, concept papers, methodologies, reports and SOPs which are required for development of the market. These tasks will be accomplished later which are listed in **Annexure-I** of this report.

It is important to mention here that the detailed design report was finalized after consultation with stakeholders and their comments and feedback is placed at in **Annexure-II** of the report.

2. Current Market Structure

Currently, the power sector of Pakistan is predominantly arranged as Single Buyer with CPPA-G acting as agent of DISCOs and KE as per the terms and conditions of the Power Procurement Agency Agreements (PPAA) signed with all of them. As established in these agreements, the CPPA-G procures power on behalf of them by signing new contracts and administering legacy contracts signed by CPPA of NTDC and WAPDA. Besides CPPA-G, KE has been operating as vertically integrated utility serving the city of Karachi and its surrounding areas.

2.1. Functions of CPPA-G

As per provisions of the Market Rules (2015) and the registration granted to CPPA-G by NEPRA, CPPA-G, being a single entity, has been performing the following functions.

1. <u>Agent of the distribution licensees, DISCOs and KE</u>.

In the context of a power sector, the role agreed in the power procurement agency agreements (PPAAs) signed between CPPA-G and each DISCO and KE is that the CPPA G acts as the agent, with the particular characteristic that CPPA-G signs contracts on behalf of DISCOs and KE (for the share that it procures through CPPA-G). As this agent activity is performed for the combined needs of all DISCOs and part of KE load, it implies that the CPPA-G is also acting as a demand aggregator. The scope of this function, rights and responsibilities of the parties are established in the PPAA, which are relevant to the conceptual design of future market and feasible transition, until the PPAA ends or is modified:

- CPPA-G has to procure power on behalf of the DISCO and KE "*to meet its licensed obligation of supply to its customers*". This statement recognizes that it is each DISCOs (and KE as Distribution Licensee) obligation to procure sufficient power to ensure supply of current and future demand of its customers.
- The ownership of the procured energy and capacity remains with the DISCOs and KE and therefore, they have the prime responsibility of the payment as well to honour those contracts signed by CPPA-G on their behalf. The same principle applies for payment of transmission Use of System Charges (UoSC). There are no liabilities on CPPA-G as the Agent due to late or non-payment by a DISCO or KE. Clause 5.6 of the PPAA states that

  > "*The DISCO shall honour any Power Purchase Agreements entered into by the CPPA-G on behalf of the DISCO pursuant to this Agreement. <u>The DISCO shall be the principal and primary obligor in respect of all payments and obligations of the purchaser towards the seller or supplier under the Power Purchase Agreements and the transmission use of system charge</u> regulated and determined by NEPRA.*")

- As the agent, CPPA-G is also responsible for carrying out the settlement function as per provisions of the commercial code that includes verifying invoices received from generators for PPAs signed or administered by CPPA G. This imposes an important responsibility on CPPA-G, as any mistake in invoices not identified that results in a payment greater than valid would be a consequence of CPPA-G not carrying out adequately its agent's function and therefore liable for the cost of mistakes.

- The DISCOs have the right to contract / procure power directly from generators, which means that there is no constraint set by the agency role of CPPA-G for DISCOs to sign Power Purchase Agreement (PPAs) or Energy Purchase Agreements (EPAs). This has never been implemented in practice. However, the DISCOs do not have the right to appoint another broker/agent. Therefore, the CPPA-G would be the exclusive agent of DISCOs. It is pertinent to mention here that although, the agency role of CPPA-G doesn't constrain the DISCOs from contracting directly with generators, however, in order to enable this trade, there are certain pre-conditions that are required to be met such as allocation of the contracts, proper design, calculation and clearance of imbalances etc. The CTBCM is designed to cater for all these preconditions so that the bilateral trade can be enabled in an efficient and market-oriented approach.
- In addition to power procurement function, the PPAA assigns to CPPA G functions that could correspond to a Market Operator (settlement, payment system, etc), but at the same time recognises that those functions are governed by NEPRA Market Operator Rules and the Commercial Code. It will be necessary to correct or clarify this overlap: the agent has the responsibility of generator invoices verification, while the market operator is responsible for the settlement and payment of the transactions in the market.
- The Agent must ensure no conflict of interest and fulfil its function for the benefit of DISCOs and KE, without other prevailing interests, but ensuring in all aspect full compliance with NEPRA Market Operator Rules and the Commercial Code.
- The DISCO (and KE) is obliged to open an Escrow Account with "sufficient credit balance in the Escrow Account for the settlement and payment" of contracted products, defined to include in addition to generation, use of system charges and market fee (para 6.2 of PPAA).

Requiring credit cover is a standard good practice in centrally administered electricity markets with multiple participants. As this obligation already exists in the PPAA in form of Escrow Accounts, it will be extended to be a requirement for market participation to provide credit cover for imbalance costs, transmission use of system (UoSC), Market Operator Fee (MoF) and other services.

2. Centralized settlement and payment

This function tends to correspond to a Market Operator in a gross pool. In the PPAA and the Commercial Code, the CPPA-G is assigned the centralized billing and settlement function, including the calculation of the average monthly transfer prices of the pool, for the PPAs/EPAs signed or administered by CPPA G and for the transmission UoSC and MoF. In practice, CPPA G is also applying this settlement and pricing function to K Electric. Additionally, CPPA G is responsible for managing the payment system for the invoiced amount to DISCOs and KE, to pay for the purchase agreements signed or administered by CPPA-G, to pay to generators as per verified invoices, NTDC as per tariff determination of NEPRA, and collects its market fee as per determination of NEPRA, when applicable.

However, all these activities are related to and based on (i) for generation, PPAs or EPAs; and (ii) for DISCOs and KE, regulations established in the tariff determinations of DISCOs and KE and in the Commercial Code. The settlement and billing, including the calculation of the average monthly transfer price of the pool and administration of the centralized payment system, are functions that characterize a Market Operator. However, Market Operator typically is responsible for administering settlement and payment systems for centrally administered markets (imbalances and spot markets), not for bilateral contracts. Therefore, it can be stated that in the context of Pakistan, both these functions relate to the agent function of the CPPA-G which shall be performed in the interest of the DISCOs and KE.

3. Market Development and Market Operator

Besides the power procurement and settlement of the PPAs/EPAs functions, CPPA-G has been assigned the function of the market operator to facilitate the transition from the current regime towards CTBCM and to establish processes and system to perform the market operations.

2.2. Conflict of Interest

The previously discussed roles of CPPA-G show that there are certain overlaps, especially in terms of the conflict of interests that arise between them at the time of implementing a competitive trading environment. To avoid conflict of interest and guarantee transparency, as the electricity market evolves to multiple buyers and sellers, the Market Operator must be totally independent from any other commercial interest in the market, in particular, not to be a party in purchase agreements, with generators or buyers that participate in the market, as CPPA-G is today.

Without this independence, there will not be a level playing field in which all players perceived that not market power could act against them. This is a mandatory requisite for investors to take part of the risks associated to long maturity infrastructure developments. In this case market power means, among other, the power to manipulate prices upward but also downwards for the interest of specific parties. The assets ownership in hands of the public sector constitutes a clear concentration that leaves independent investors in a weak position to manage their own risks.

Therefore, without having the entity that administer all transactions in the market, the Market Operator, fully independent from any commercial interest in the market, the level playing field necessary for the achievement of the goals will not be reached and with that the implementation of a competitive market will not be possible.

CPPA-G is well aware of this fact and has been taking steps in bifurcation of the agent role from the market operator role as per the directions given by NEPRA in the Market Operator registration terms and conditions. Further, NEPRA has issued this direction in the CTBCM approval determination to remove this conflict of interest and establish an independent market operator. This action is part of the CTBCM implementation roadmap with detailed steps and timelines which will be submitted to NEPRA for approval.

2.3. Trading Arrangements in the CPPA-G Market

The current trading arrangements being centrally administered by CPPA-G can be summarized as follows:

- As agent, CPPA-G on behalf of DISCOs and KE negotiates new PPAs/EPAs. In carrying out this function, CPPA-G is bound to follow existing NEPRA regulatory framework, including the procedures for NEPRA initial approval or clearance of allowing to negotiate or procure new contracts. In principle, this demand aggregation function should include assessing demand projections provided by DISCOs and KE as per regulatory codes and capacity already contracted, to calculate the gap that corresponds to new capacity that needs to be contracted.

 - A weakness in this process was that DISCOs were not providing their forecasts to CPPA-G as per the requirements of the Distribution Code, however, with the efforts of CPPA-G, this function has been resumed at DISCOs and they have started preparing medium term forecasts as per provisions of the Distribution Code with facilitation from CPPA-G and NTDC. It will be further beneficial if they start submitting this forecast to NEPRA for review and approval.
 - As each DISCO and NTDC already have the obligation to forecast demand, the procedure for procurement in compliance of the applicable regulatory framework shall be that DISCOs and NTDC collaborate in preparation of the demand forecast and then NTDC prepares its least cost generation and transmission expansion plan which shall be approved by NEPRA. CPPA-G shall only be allowed to procure power and enter into contracts with generators as per approved generation plan.

- <u>Currently, trading of electric power is only through long term PPAs/EPAs</u>. Prices of PPAs or EPAs are not negotiated, as generation prices are currently subject to NEPRA tariff determination, reflecting the technology, fuel, efficiency, etc. Therefore, commercially the main purpose of the PPA/EPA is to establish provisions on buy and sell obligations, invoicing and payment arrangements, dispute resolution and other administrative arrangements. However, generation prices can be determined through the market if the PPA/EPA is awarded through a competitive process approved by NEPRA as per the NEPRA's Competitive Bidding Regulations (2017). However, since the promulgation of these regulations, no competitive bidding has taken place.
 - Generators (GENCOs, Nuclear, WAPDA hydel and IPPs) with PPAs or EPAs signed or administered by CPPA-G sell all energy injected / measured or estimated at market entry point (connection to NTDC grid or to DISCOs' transmission facilities). The PPAs have a two-part tariff structure i.e. fixed capacity payments and variable energy charges, while EPAs have single part tariff. PPAs are signed with dispatchable thermal generation and hydel plants and EPAs are signed with non-dispatchable renewable generation plants.
 - Imports are commercialized through PPAs signed or administered by CPPA-G. Energy is injected at the interconnection point, and scheduling of the exchanges is the role of the System Operator to ensure coordination with power systems in other countries, in accordance with the Grid Code.

   In the future, if there is surplus in Pakistan power sector, eventually the interconnection could be used also for exports. The future market design fully considers this (discussed later) and allows for imports (purchases) and exports (sales) in international interconnection, with a maximum limit to exchanges (net transfer capacity) calculated periodically by the System Operator to comply with system security constraints, as established in the Grid Code.
 - Small power plants connected directly to a distribution network are allowed to sell directly to the corresponding DISCO through physical PPAs (two part or energy only depending on technology).

- NTDC and DISCOs are acting as metering services providers, reads/collects monthly commercial metering data. As part of the metering services providers, NTDC and DISCOs are also responsible for validating, testing and calibration of the metering system. The metering data is collected by the metering committees and provided to CPPA-G for billing and settlement purposes. At the end of each month, National Power Control Centre (NPCC) of NTDC as System Operator sends to CPPA-G, the availability and despatch data of power plants, for the verification of capacity payment and to determine if liquated damages apply. The metered data is also used for settlement and invoicing of DISCOs and settlement of KE.

- On a monthly basis as established in the PPA/EPA, each generator sends the invoice to the party that signed the agreement. It must be noted that, until PPAs/EPAs are novated, invoices for PPAs signed by WAPDA would go to WAPDA Private Power Organization (WPPO) and those signed by NTDC would go to NTDC. Similarly, any complaint due to late payment or incorrect payment by an IPP would be directed to WPPO or to NTDC as applicable. As neither WPPO nor NTDC have an agency agreement with DISCOs but CPPA-G does, it is crucial for the market development and transparency that PPAs/EPAs are transferred / assigned to CPPA-G as a successor company.
- The monthly energy procurement data (quantity, charges, and total cost) is sent by CPPA-G to NEPRA for the determination of the monthly Fuel Price Adjustment of DISCOs and KE, including confirmation by CPPA-G and NPCC of NTDC as System Operator. Currently, this activity is not covered in the Commercial Code. NEPRA determination may identify differences or inaccuracies in the power purchase data submitted by CPPA-G, or other factors that disallow certain costs if inconsistent with tariff determination or purchases in special cases such as lack of generation license.
- Using the metering data provided by NTDC, the generation costs resulting from the verified invoices (in principle, with the adjustments that may result in the review and determination by NEPRA of generation allowed costs for the Fuel Price Adjustment), CPPA-G calculates the monthly capacity and energy transfer price and the transmission use of system charges of NTDC, and carries out the settlement and invoice of each DISCO and KE, separating the power purchase cost (energy and capacity) and the payment for the transmission system and market operator fee.
- During the month, there are daily payments by DISCOs to CPPA-G and there are daily payment instructions to generation companies and to NTDC by CPPA G.
- Currently, generation costs are accounted monthly. Therefore, the **trading period** in the CPPA-G administered market is monthly, and the market (pool) price is the monthly weighted average. The billing and payment for distribution licensees is also monthly. A shorter market pricing, settlement and payment period will allow to reduce the amount of credit cover required from each participant and identify earlier when a participant is not complying with its payment obligation. Interest for late payment will also be defined and applied for the market payment period (daily or weekly interest).
- In a Single Buyer market model, the regulations and methodologies required are, in addition to principles and procedures to authorize or approve generation costs, to establish the Bulk Supply Tariff (BST) at which the Single Buyer resell electricity to the wholesale purchasers. The BST will reflect the total allowed power purchase costs to be transferred, partly similar to the allowed total generation costs in the case of an integrated utility[2]. However, the BST may have different structures that affect how the allowed power purchase costs are allocated among wholesale buyers (mainly distribution companies in the role of suppliers), such as the following:
    - energy only BST having only single price per unit of electricity;

[2] The BST may include as a separate component the administrative and operational costs allowed/regulated for the Single Buyer.

- two-parts energy and capacity BST charged separately of energy consumption and peak demand;
- BST reflecting average costs (e.g. monthly) actual;
- planned generation costs and later adjustment for conciliation with actual;
- BST differentiated by time of day and/or season to reflect the actual cost of generation.

In Pakistan, the creation of the CPPA function was formalized in the NTDC license granted in 2002. The energy and capacity transfer price mechanism to pass through generation costs was formalized in the initial tariff determinations of DISCOs and of NTDC (at that time, the CPPA function was part of NTDC).

- CPPA-G is buying as an agent of the DISCOs and KE[3] . Therefore, the costs and benefits of each and all PPAs should, in principle, be equally shared among DISCOs (including KE). As explained earlier, CPPA-G is not liable for non or late payment by DISCOs and KE and is allowed to recover any late payment costs invoiced by Generators (in accordance to the PPA/EPA) from the DISCOs or KE that caused the late payment.
- The generation component of the transfer price has a two-part structure (energy and capacity), to recover average monthly allowed energy and capacity generation costs based on invoices by Generators in accordance with provisions in the PPA or EPA and NEPRA generation tariff determination (the latest notified). CPPA-G is responsible for invoice verification, in representation of the interests of DISCOs. This two-part structure replicates that tariff structure allowed by NEPRA for power generation that comprises of capacity payments which covers the fixed costs including returns on investments and the energy payments cover the variable generation costs that are incurred while generating electricity i.e fuel costs and variable O&M.
- The monthly energy taken from the grid by a DISCO and KE is valued at the monthly average energy cost component / transfer price. The transmission losses (up to the cap imposed by NEPRA) are implicitly accounted for in the calculation of the monthly average transfer price. Therefore, the payment reflects the benefit received in energy by each DISCO and KE, which is the energy the company can distribute and sell to its customers. This approach is similar to assuming that in each period (e.g. hour) each DISCO and KE took a percentage of the energy generated equal to the share its monthly energy represents in the total monthly energy. This assumption is not fully true as allocation and supply may vary by hour and some DISCOs or KE could be taking a larger share in periods or hours when generation is more costly. However, as the transfer price is a monthly average (there is no type of day or time of day pricing), this sharing principle has been implemented and accepted by all DISCOs.
- The monthly maximum demand (capacity) taken from the grid[4] by a DISCO or KE is valued at the monthly generation capacity cost component / transfer price. Therefore, the payment reflects the benefit received in covering the peak demand contribution of the respective DISCO or KE in the system peak. This approach is similar to assuming that the installed and available generation capacity (the generation capacity paid) is justified in providing security of supply for the demand, subject to load shedding. It could be considered that the monthly capacity price reflects the

[3] For the purpose of this report, whenever the word DISCO(s) is used in reference to sale and purchase of energy and capacity, it refers the DISCOs acting as Supplier under the existing framework or a separate supply license has been obtained under the provisions of the Act. A specific reference will be given when reference is given to the distribution business of the DISCOs.

[4] There have been conflicts in interpretation and implementation of maximum demand of the DISCO: whether its maximum demand (non-coincidental peak) or its participation in the system peak demand (coincidental peak). For the purpose of this document, it is not a relevant issue except in highlighting that the market design and its code and procedures need to be clear in definition of demand by DISCOs and Bulk Power Consumers, and capacity paid to generators.

cost/price of security of supply for the DISCO and KE and its consumers, and the price varies monthly.

- In summary, the current and historical CPPA/CPPA-G practice is based on a general principle of equally sharing PPAs/EPAs costs, allocating these costs on an average monthly basis depending on the share of energy and of peak demand of a DISCO and KE[5] within the total for all DISCOs and KE (the share procured through CPPA-G). This ensures each and all DISCOs and KE have the same regulated wholesale (purchase) price for energy and generation capacity, and that this wholesale price is transferred as a cost to average regulated end consumer tariffs with a monthly fuel cost adjustment. CPPA-G settlement for each DISCO and KE uses the same wholesale transfer price (Capacity Transfer Rate (CTR) and Energy Transfer Rate (ETR), in accordance with NEPRA tariff determination and tariff guidelines. At the wholesale level, which is the focus of this document, each and all DISCOs and KE would pay the same wholesale price (as well as the same transmission use of system charge and Market Operator Fee.).

2.4. Trading Arrangements In KE Served Area

KE has been operating as an Integrated Utility and has been granted generation, transmission and distribution licenses by NEPRA to provide electric power services in the city of Karachi and its surrounding areas. KE fulfils the demand of its consumers through its own generation, contracting power from IPPs through long-term contracts and purchasing some amount from the national grid (CPPA-G pool). As an integrated utility, KE also perform the function of the System Operator for its own system. All of the generation, transmission and distribution costs are approved by NEPRA and passed on to end-consumer tariffs. Currently KE has been granted a multi-year tariff till June 2023 by NEPRA as vertically integrated utility.

[5] Whenever a reference is made to KE along with DISCOs regarding its demand, it is meant only that portion of its demand which is procured from the national grid.

3. Transition from Vertically Integrated Utility or Single Buyer Model towards a Competitive Market

As explained above, in a vertically integrated utility or single buyer model, the generation costs are accumulated as single cost and transferred to the end consumer tariffs. There is no discrimination among the consumers in sharing of the costs of specific generation plants or contracts. However, in a competitive electricity market allowing the participation of multiple wholesale buyers and sellers and bilateral contracts, each participant may have more than one bilateral contract. Depending on contracts designs (which are explained later), typically it is not possible to ensure that the energy or capacity bought through these contracts by a Supplier will be equal to the energy and capacity required to supply the consumption (energy) and (security of supply, peak) demand (capacity) of its consumers. The market approach that has been implemented internationally is to develop balancing mechanisms or spot market/pools that clear the difference between contractual quantities and actual energy consumption and demand requirements or capacity obligations (discussed later)[6].

Therefore, moving from a vertically integrated utility or from a single buyer structure or from a central wholesale agent based structure (as is currently CPPA-G) to a multiple sellers and buyers wholesale electricity market with bilateral contracts, requires an adequate market design to take into consideration bilateral trading and, in consequence, also the review and adjustment of the regulations, codes, agreements and procedures, including the need for the following considerations and decisions:

- The mechanism for the explicit allocation of energy **transmission and distribution[7] losses** (or cost of transmission and distribution losses) among demand participants such as independent[8] suppliers and/ or, bulk power consumers, connected to the grid. Several approaches (design and methodologies) are discussed in this report later together with indicative examples and recommendations have been made with the preferred approach.
- **For the contract market**, the new contract design in the market which will evolve towards financial instruments that will cover the volatility of generation prices/costs for the buyer and will ensure a cash flow for the seller. The new contract designs must include provisions for security of supply of the buyer through the purchase of generation capacity subject to performance / availability obligations on the seller;
- **In the balancing mechanism for energy**, the pricing mechanisms through which the generation energy imbalance is valued and also how often is the energy imbalance quantity and price determined (the trading period for the balancing mechanism for energy);
- **In the balancing mechanism for capacity,** how is the capacity balancing price determined and how often is the capacity imbalance quantity and price determined (the trading period for the balancing mechanism for capacity).

All these aspects are covered in the CTBCM design and are discussed in this report. The CTBCM is designed as a bilateral contract market with balancing mechanisms. The main purpose of this report is to analyse the design and features of the CTBCM design and Market Structure and to work out the details

[6] Capacity markets / pools/ mechanisms tend to define the demand as capacity obligations of supplier / load servicing entities, and the offer as actual available generation capacity.

[7] In case of BPC embedded in the Distribution Network

[8] Suppliers other than the Last Resort Suppliers

of the concepts presented in the approved CTBCM conceptual design report. This report will enable the readers to understand the concepts of CTBCM in detail and way forward to translate these into rules and regulations to be promogulated for the implementation of the market.

4. Market Structure: Participants and Services Providers

The market structure is defined by types and functions of **Services Providers** (companies that provide non-discriminatory services to all Participants, but do not buy or sell electricity in the market (without any commercial interest in the market)) and **Market Participants** (companies that buy and / or sell electricity in the market) having commercial interests in the market.

4.1. The Case of the CPPA-G

As already mentioned, there are conflict of interests in the existing CPPA-G due to the different functions currently being performed. The proposed market structure separates these two kinds of functions into different companies to ensure transparency, avoid conflict of interest, and manage the transition to a market which is based on direct bilateral contracts between the buyers and the sellers.

As a result of this action, the following successor companies would result from the restructuring of the current CPPA-G:

- **The Market Operator (MO):** The Market Operator will be a Service Provider in the market responsible for the development and administration of the market. The functions of the Market Operator are described in *Section 17.2* of this report.
- **The Special Purpose Trader (SPT):** The Special Purpose Trader (SPT) will be registered with NEPRA that will administer all the contracts currently being managed by CPPA-G. It is envisaged that the current CPPA-G will take over this function. This will also require the modification in the current PPAAs with DISCOs and KE.

4.2. Service Providers

The **Services Providers** will be same or similar entities that are providing different services as of today, however, additional requirements and responsibilities will be introduced for the System Operator, metering service providers, planner etc. with introduction of the function of a Market Operator.

4.2.1. Market Operator

The **Market Operator** will be a licensed entity as per the Act and will be responsible for the organization and administration of trade in electricity and payment settlement among market participants. The Market Operator will be responsible for administering the admission and registration of participants and contracts, the calculation of price and security cover for participating in the wholesale market, settlement and payment system for the centrally administered markets, market design and product development and market surveillance. Initially, as trading will be mostly through bilateral contracts between buyers and sellers, the Market Operator will implement and administer only Balancing Mechanisms to clear differences between actual and contracted quantities. As the market develops and moves to portfolio of market-based contracts with long, medium and short term duration to hedge prices, it will be possible to assess adding medium to short term power procurement platform administered by the Market Operator.

4.2.2. The System Operator

The **System Operator** will be a licensed entity as per the Act providing efficient and transparent dispatch services and being responsible for the transmission system reliable operational planning and coordination of maintenance outages, centralized economic generation scheduling and dispatch, operation and control of the transmission system and keeping the system in balance within security and reliability constraints.

The System Operator (NPCC of NTDC) will be responsible for the centralized security constrained economic dispatch, including management of demand control and exchanges in international interconnections.

The System Operator will administer open access to the transmission grid and therefore must be independent of commercial interests of existing and potentially new Participants that trade in the market.

The System Operator is governed mainly by the Grid Code, and also by any right and responsibility assigned in **Transmission Connection Agreements** and **use of system** agreements to implement fully open access for bilateral contracts.

As already established in NTDC licence, the System Operator will have functional and accounting separation from NTDC as Transmission Services provider (or Transmission Network Owner – TNO). At later stage, if it is considered appropriate, it may be established as an independent company to foster greater confidence in the market. Also, to comply with the Act, the system planner function shall also be made part of the System Operator.

4.2.3. Metering Services Providers

The network companies providing transmission and distribution services will provide the metering services as well. Similar to current arrangements, NTDC responsibilities will include metering services at connections to the transmission grid; the distribution licensees will be responsible for metering services of power plants and Bulk Power Customers at connections with its distribution network. Other transmission licences (PGCs and SPTLs) will also be responsible to provide metering services to the parties connected to their networks. KE as transmission and distribution company (when integrated into the market) would be the metering services provider in its licensed area. These metering services will provide the metered data for the centrally administered markets settlement as well as bilateral trading between parties.

In accordance to the provisions of the Grid Code, NTDC responsibilities as metering services provider include provision of the revenue meters at each common delivery point (CDP), read/collect commercial metering data as well as validating, testing and calibration of the revenue meters.

The metered data will be provided to the System Operator, NTDC Planning, and to the Market Operator. The Market Operator will make this information available for Participants that require it for doing transactions under their bilateral contracts, in particular to the SPT including also the availability and dispatch data of power plants which will be provided by the System Operator to Market Operator.

The Distribution Licensees will perform the metering service as per provisions of the metering code of the Distribution Code which will be reviewed to identify gaps and recommended amendments if required. At later stages of the market development, a comprehensive metering code may be introduced which shall be applicable to all metering service providers.

4.2.4. Transmission Services Providers

Transmission services providers or Transmission Network Owners (TNOs) are responsible for providing the transmission infrastructure that enables wholesale buying and selling, and wholesale competition. NTDC is the main TNO and the National Grid Company and it must ensure that its system is well maintained, and it shall also coordinate with other transmission licensees to adequately design, build and maintain their transmission facilities (provincial grid companies and special purpose transmission licensees).

NTDC as transmission services provider will ensure adequate economic transmission. Under the Planner function, NTDC will develop a 10-year transmission expansion plan together with an indicative generation plan as per provisions of the Grid Code and other applicable rules and regulations. The planning procedures and standards will be in accordance with the Grid Code, guaranteeing predictability and transparency. The transmission plan for first 5 years will be considered mandatory and for the last [5] years indicative. NTDC will produce annual updates of the transmission plan informing congestion and impact on dispatch costs and supply, any delays in investment, impact on system security constraints and measure to address delays and constraints/congestion and inform locations best suited for new generation. The transmission expansion plan and the least cost indicative generation expansion plan, once approved by NEPRA, will be publicly posted on the Planner website.

4.2.5. Distribution Network Services Providers

DISCOS and KE as **distribution network services providers** (and distribution network operators) will develop adequate and reliable networks under their respective jurisdictions.

Distribution Licensees will prepare 5-year investment plans, subject to NEPRA review and approval, in accordance with Distribution Code and tariff regulations and/or guidelines, to accommodate forecasted demand growth, and connections of generation to distribution network (distributed generation) and net metering arrangements.

4.2.6. Independent Auction administrator

In order to manage the transition from current regime to a completely bilateral contract market where DISCOs will be procuring electricity directly, the independent auction administrator (IAA) will facilitate DISCOs in this procurement. IAA will aggregate the demand from all DISCOs and will procure power through competitive bidding, however, the contracts will be signed by the DISCOs that require the energy and capacity to be procured in order to meet the needs of their customers. The detailed functions of the IAA are discussed in *Section 14* of this report.

4.3. Market Participants

As discussed above, market participants are those entities who buy or sell electricity in the market and thus have commercial interests. The market structure proposed for the CTBCM allows the following types of **Participant**s in the market.

4.3.1. Generators

Generators will be licensed entities from NEPRA (till the licensing regime exist as per Act.) involved in **generation and** selling of electricity and make available their capacity to System Operator for centralized economic dispatch and ancillary services for system reliability and security of supply as per provisions of the Act. and the Grid Code.

Establishment of the ancillary services requirements and its obtention will be a function of the System Operator, as established in the Grid Code. The Grid Code will be reviewed to identify gaps and propose necessary amendments. A methodology will be established on how to procure the services and how to allocate the cost of these services to different market participants.

Power plants will be dispatchable (subject to centralized security constrained economic dispatch by the System Operator) or non-dispatchable (e.g. solar, wind, small run of river hydro, etc.) in accordance to conditions, requirements and procedures in the Grid Code.

- There may be a trader to act as generation aggregator: This trader may be a company that agrees with several small power plants and will act in their representation in the market, to sell the aggregated energy and capacity of the group of power plants in the market.

Small generation connected to distribution network that sell to BPCs must become Participants, to participate in the Balancing Mechanism. Alternatively, the generator can delegate participation to a trader that participates in the market.

Other generation connected to distribution not included in the centralized economic dispatch of the Grid Code can opt to participate in the market, in which case they must comply with requirements, information exchange as required for participant generators.

4.3.2. Bulk Power Consumers (BPC)

Bulk Power Consumers (BPCs) are those consumers which procure electricity in bulk quantities and are allowed by the Act to buy electricity (energy and capacity) from the market trading arrangements. As established in NEPRA Act, the criteria (voltage, demand) to for a consumer to qualify as BPC will be established by NEPRA[9]. The BPCs will have two options to procure power in the CTBCM (i) through direct participation (and registration as Market Participant by fulfilling the requirements of a participant), or indirect participation through buying its supply from a Supplier as described later (the retail supplier is the Market Participant in representation of that BPC).

4.3.3. Suppliers

Suppliers will be licensed entities as per the Act. and will involve in selling electricity to end consumers. Suppliers are participants that buy electricity in the market and sell it to consumers including BPCs and others. As per standard practice in the market and provisions of the Act., based on the core activity of supply to end consumers, suppliers can be broadly categorized as following:

[9] Defined in NEPRA Act meaning "*a consumer who purchases or receives electric power, at one premises, in an amount of one megawatt or more or in such other amount and voltage level and with such other characteristics as the Authority may determine and the Authority may determine different amounts and voltage levels and with such other characteristics for different areas*"

- **Competitive Suppliers:** These are suppliers involved in supplying energy to those consumers which are given the possibility to choose their own suppliers. Such consumers are also called eligible consumers. In the context of NEPRA Act. currently the BPCs are the eligible consumers. The international experience shows that, at the initial stages of the market, a relatively strict criterion is established to qualify as eligible consumers, limiting the number of consumers that may exercise this possibility. However, as the market matures, appropriate metering systems are implemented and adequate processes are established, gradually more consumers are given the possibility to choose their supplier and, hence, larger retail competition is introduced.

  In the case of Pakistan, a supplier regime will be introduced granting supplier licenses to qualified companies which should supply only to BPCs. Once the wholesale market is matured, this choice of suppliers will be gradually extended to all other consumers as well, and hence full retail competition will be introduced. These suppliers will negotiate the price and conditions of the supply with their customers and such conditions and prices will not be determined by NEPRA. These suppliers can request a specific territory or can be granted a license to sell to eligible consumers across the country.

- **Last Resort Suppliers:** These will be licensed entities with specific territory specified in their respective licenses, which will be responsible to provide supply to all consumers located in such territory which require it (including those BPCs who are not getting supply from a Competitive Supplier). These suppliers will sell electricity at the regulated rates and can't bilaterally negotiate with any of their consumers or any other party that they are selling to. These suppliers will also be responsible to supply to those customers whose Competitive Supplier has defaulted, until they find a new supplier. In CTBCM, the suppliers of the incumbent DISCOs and KE will be assigned the functions of the last resort suppliers.

The supplier will perform the following functions:

- **Procurement of Power:** The suppliers will procure power in the market form generators, traders (including imports), and possibly other suppliers to meet the demand of their customers. All suppliers will have capacity obligations (discussed later) to ensure security of supply for their consumers. The Competitive Suppliers will bilaterally negotiate their prices with the parties from whom these are procuring power. The procurement of the last resort suppliers will be through competitive bidding subject to procurement regulations to be published by NEPRA. The suppliers will also be allowed to install their own generation subject to obtaining the required regulatory approvals and licenses.
- **Selling of power to end consumers:** The other main function of the suppliers would be to sell electricity that they have bought through contracts to their customers. The suppliers will establish procedures for collecting metering data from the metering service providers and billing to their customers. The Competitive Suppliers will sell electricity at negotiated rates, while the last resort suppliers will sell to the consumer at rates approved by NEPRA, not being able to bilaterally negotiate them with their customers.
- **Selling to other entities:** The supplies will also be allowed to sell electricity that they have contracted to other parties including traders, generators and other suppliers.

4.3.4. Traders

Traders will be licensed entities in CTBCM that will involve in buying and selling of electricity in the market to/from all participants except consumers. The trader will not be limited to any territory and its buy and sell rates and conditions will be bilaterally negotiated and will not be subject to approval or supervision by NEPRA, other than from market monitoring and/or market power evaluations conducted either by the Market Operator or NEPRA. The trader will perform diverse functions as summarized below:

- The Trader can be active in power trade (imports and exports), such as import from another country and to resell to another trader or a supplier (including last resort suppliers).
- A trader can aggregate generation from many generators and can sell it in the market as representative of the generators.
- One or more Traders that are Participants will be required to represent companies in an interconnected power system, for imports and exports of electricity.
- Similarly, a Trader can represent as Participant, the generation that are not covered under the jurisdiction of NEPRA Act. and have a special regime that cannot be assimilated to the Market and become a Participant (e.g. Neelam Jhelum in AJK).

4.4. Special Purpose Trader

As discussed above, the Special Purpose Trader (SPT) will be a registered entity with NEPRA that will continue to administer the current long-term contracts signed or administered by CPPA-G. The SPT will provide this service to the DISCOs similar to as CPPA-G is doing today. Future contracts[10] will be bilaterally signed between generators and the DISCOs.

[10] Special consideration will be given to strategic projects that require sovereign guarantee to analyse their commercialization in CTBCM.

5. Main Principles of the Market and Trading Mechanisms

> ***The Target**: A wholesale competitive electricity market with bilateral contracts and capacity obligations to guarantee security of supply, combined with balancing mechanisms to enable centralized economic dispatch and promote enhanced demand forecasting and adequate reserve. All trading arrangements (through contracts or in the centrally administered market mechanisms) will be backed by credit cover to minimize non-payment risk.*

In order to reach the target market, the design of the market is based on certain principles to reap the benefits of competition. The following section describes the principles and characteristics that define the proposed conceptual market design:

5.1. Products Traded in the Market

Any market is characterised by the types of the products traded in the market i.e. commodity markets, financial markets etc. In CTBCM, two separate products will be traded in the market: energy to supply electricity consumption; and "firm capacity" to provide sufficient and adequate capacity for medium and long-term security of supply.

- Energy and capacity will be traded mainly through contracts, complemented by trading through balancing mechanisms administered by the Market Operator.
- Participants representing demand (e.g. DISCOs, K Electric) or consuming electricity (BPCs) must procure or own sufficient firm capacity to supply actual demand and forecasted peak. For generators, firm capacity is provided and sold by committed and actual availability. The general design of the Capacity Obligations and the Balancing Mechanism for Capacity are described at *Section 12* of this report.
- **Energy:** Energy is the actual electricity produced to perform the actual useful work and is measured in kWh. This will be a standard product traded in the market and will be measured through commercial metering systems installed by the metering service provider.
- **Capacity:** Capacity is the ability of the generation assets to produce electricity whenever needed. The concept of Capacity is related to the security and reliability of the electric power system and is used in various markets to remunerate capacity of the power plants. In CTBCM, Firm Capacity will be a certified product and procedures will be established to calculate firm capacity of different type of generation technologies and to assign then a firm capacity certificate. The details of the methodologies adopted for calculating firm capacities of renewables are provided in the IE-MSM report developed by CPPA-G. The selected methodology will be approved by NEPRA and firm capacity factors will be calculated for each type of technology.

5.2. Capacity Obligations

All Participants representing demand must **contribute, according with their share, to the secure and reliable supply** of the power system by planning and contracting in advance enough available generation and reserve resources to meet their demand. A Balancing Mechanism for Capacity (discussed below in this report) will also contribute to achieve this objective.

Network services providers (i.e. Transmission Service Providers and Distribution Service providers) will contribute by planning and ensuring network upgrade and expansion sufficiently in advance to ensure that the committed power is efficiently dispatched and there are no congestions and constraints in the network.

Capacity Obligations is a very important feature of CTBCM and are introduced to procure sufficient (not more nor less) capacity in advance to meet the total system needs to avoid any deficit or surplus in future. Capacity Obligations will strictly be observed and there will be severe penalties for violation of the obligations.

<u>The Capacity Obligations will be introduced in the following manner</u>:

- DISCOs as Last Resort Suppliers must have enough capacity and adequate energy contracted in advance, to cover [100%] of their forecasted contribution to the system peak demand and operational reserves to meet the demand of its consumers for the next [3] years, [90%] for years [4 and 5), [75%] years [6 to 8], and [60%}, for years [9 to 12]. This requirement is consistent with obligations in the distribution license and shall also be incorporated in the supplier license when such license is issued. Initially, DISCOs will inform before the end of each year, for next 10 years annual and monthly demand forecast to IAA which will accumulate these figures and identify needs for new capacity procurement for each DISCO and will carry out procurement for the combined needs and will allocate the contracts as per requirement of each DISCO. The total new capacity additions required for the system will be established in the IGCEP. The IAA will segregate that requirement into shares for different DISCOs and procuring the total gap. This process will be undertaken by IAA for certain period and then DISCOs will be performing these tasks by themselves.

Note: The percentage of contract coverage under different horizons open for discussions. The objective is to ensure entry of new capacity through contracting sufficiently in advance but avoiding the risk of over-contracting in case demand is lower than forecasted, or later demand forecast estimate a lower growth. Considering the time required to build new generation capacity, the first three years horizon corresponds to the period when already power plants are under construction.

- As an integrated power utility, KE will develop its own generation and sign contracts with IPPs and will be subject to same obligations as DISCOs. On an annual basis, KE will inform the Market Operator for next 10 years its demand forecast and power generation plan (existing and new procurement), and the estimated shortfall or surplus. The plan will be updated each year with a rolling 10 years horizon. In principle, the Capacity Obligations for KE should be aligned to that of DISCOs.
- A Bulk Power Consumer (BPC) that participates in the market must contribute to security of supply through contracting capacity in the bilateral PPA/contract or purchasing part of this capacity from the market. The Bulk Power Consumer must inform [5] year estimated demand and power procurement of capacity, estimated shortfall or surplus. Until the Balancing

Mechanism for Capacity be fully implemented, the capacity obligations of the BPC will be similar as those to other suppliers. Later on, the minimum obligations will be decided by NEPRA. A BPC or a group of BPCs can delegate to a supplier its direct participation in the market, subject to signing a retail supply contract. When a Supplier represents one or more BPC in the market, the Capacity Obligations of that demand becomes a responsibility of a Supplier as Participant. The Supplier will contract and inform power supply plans for the aggregated demand of the BPCs it represents in the market

- A Competitive Supplier, which has contracts with Eligible Consumers and, therefore, participates in the market, shall contribute to the security of supply signing contracts with generators, traders or other suppliers and/or, when this Balancing Mechanism for Capacity be implemented purchasing it from the market. The Supplier shall inform its [5] year estimated demand and shall demonstrate it has enough capacity contracted to cover, at least, [100%] of the demand its consumers for the next year, [90%] for years [2 and 3] and [75%] for years [4 and 5]. NEPRA will adjust, periodically, these percentages taking into account the evolution of the market (in particular the Balancing Mechanism for Capacity) and the information submitted by the System Operator in relation with the reliability of the system.

5.3. Firm Capacity of Generators

As described above, all market participants which have or supply demand (DISCOs, KE, Competitive Suppliers and BPCs) have the obligation to contract, in advance, part of their Capacity, contributing in this way to the security of supply i.e. there is always enough generation available in the system to meet the demand. This, in turn, requires determining the amount of Capacity that each generator (or group of generators) is capable provide taking into account that not always such generator is available or it is capable to provide 100% of its nameplate capacity.

The concept of Firm Capacity considers several factors that affect the availability of different types of generators while evaluating the security of the system. Based on the criteria of availability, there are three types of generators:

- **Dispatchable Generators:** These are generators which can dispatch energy on demand meaning that they can increase or decrease their energy output as per requirements in the system. These plants are normally thermal based generation or large reservoir based hydro power plants
- **Non-Dispatchable Generator:** These are the type of generation which can't vary their output as per requirements of the system. These plants generate electricity as per their natural patterns. Normally these plants are based on non-controllable fuel sources such as wind, solar and run-of-river hydro.
- **Energy Limited Generators:** These generators are, in principle, dispatchable, but have inherent limitations which limit the range of such dispatch. This is usually the case of hydraulic units, which have a limit on the total energy they can generate during a certain period, being this period a day, a month or a year.

The dispatchability of power plants has an important role in the security of a power system as demand doesn't remain constant and varies all the time, therefore, there must be some generation sources in the system that can follow those variations in order to keep the system stable. Besides normal load variations, there can also be emergency conditions in the system during which sudden increase or decrease in generation will be required. For example, in case of failure of a generating plant, other plants must be able to quickly increase their generation to make up for the loss of generation. Therefore, this characteristic of dispatchability of the generation must be rewarded as well.

With the increasing share of variable renewable generation which don't offer the dispatchability, the concept of Firm Capacity was introduced in order to provide a level playing field for all players in terms of providing security to the system. There are several methods used to calculate the firm capacity of the variable renewable generation and energy limited generation. Some of these methods are simple and easy to implement, while some others are more complex involving system simulation and convolution. Following are few examples:

- **Most loaded hours approach:** This is a very simple approach which is based on the contribution of each type of technology to the security of the system during the most loaded hours. The underlying assumption is that the system is most stressed during these hours.
- **Critical hours approach:** This is a relatively complex approach in which the contribution is calculated based on the reserve margin in the system i.e. the contribution is measured in those hours where the reserves were very short. This approach has been implemented in several countries (i.e. Mexico, France) as well.
- **Equivalent Capacity Approach:** This approach is based probabilistic simulation in which the impact of the renewable capacity addition is observed on the improvement of the LOLP[11] of the system.
- **Convolution Integral Approach:** In this approach, the firm capacity is calculated through complex formulation of convolution integrals.

For Pakistan, it is recommended to start with the simple approach of the most loaded hours at the start of the market and then gradually move towards the more sophisticated methodologies.

5.4. Bilateral Contract Market

The main component of the market is the Bilateral Contract Market meaning that electricity will be traded mainly through bilateral contracts.

- Consistent with current practices and international experience in power sectors with significant demand growth and/or inadequate payment culture, trading will be mainly through bilateral contracts/PPAs/EPAs. Each Supplier e.g. DISCOs, KE, Competitive Supplier or BPC that participates directly in the market will sign contracts directly with Generators or other Traders or Suppliers to cover their Energy requirements and Capacity Obligations.
- Two types of contract will coexist in the Contract Market: pre-existing physical PPAs/EPAs and new Supply contracts (market-based contracts signed under the new market framework). The market-based contracts are described later in this report.

Pre-existing PPAs and EPAs will be commercially allocated to DISCOs proportionally to its share of the aggregated demand of DISCOs and KE (the share that it is supplied under PPAA with CPPA-G). All the existing PPAs or EPAs will be legally assigned to the Special Purpose Trader (SPT) and the SPT will be performing the administration and settlement function in similar manner as is performed today by CPPA-G (as per provisions of the amended commercial code). For this purpose, the current PPAAs of each DISCO and KE with CPPA-G will be reviewed accordingly to reflect market design and transition. It is important to mention here that the SPT will administer the contracts in a manner as if these

[11] Loss of Load Probability

contracts are legally bilateralized among DISCOs. The existing commercial code will also be amended to reflect the market design and to align it with the new role of the SPT. The SPT will calculate the share that corresponds to each DISCO and KE, and for each period, the energy and capacity quantity and payment that would correspond to each DISCO and KE should be considered as bilateral contracts. The purpose is (i) to assess and adjust as necessary the criteria for later assignment among DISCOs and KE; and (ii) to facilitate the assignment later as the PPA or EPA has already been simulated as a bilateral contract with each DISCO and KE. For the purpose of compliance with Capacity Obligation of each DISCO and KE, it will be assumed that each DISCO and KE has contracted the quantities simulated by the SPT.

- As stated earlier, in order to facilitate the transition, the current function of CPPA-G shall be adopted to the function of SPT with necessary adjustments to its business processes. For example, the settlement function shall be administered as per provisions of the amended commercial code.
- Market-based Supply Contracts will be flexible to adapt to different generation and demand profiles and the requirements imposed by different kind of consumers. The energy actually generated will be the result of competition for dispatch. This will let the Participants not only to meet their Capacity Obligations but also to hedge prices (stabilize and protect from volatility).
- Contracts can be financial instruments to hedge prices, or only physical (deliver energy and/or offer available capacity), or a mix of financial and physical. The Balancing Mechanism described later allows flexible contractual agreements and more diversified trade, as it is possible to also trade in the short term.
- The market regulatory framework, including the Grid Code, Distribution Code, commercial code for the SPT (previously the Commercial Code) and Market Code (commercial code for MO) will be the basis of the market, and the framework that all contract must comply with. Therefore, the provisions in the contracts will establish that in case of any inconsistency or discrepancy with a Code, the Code will prevail to the extent of the inconsistency.
- For the purpose of the Balancing Mechanism, all contracts must be registered with the Market Operator informing buyer and seller, term, energy and/or capacity contracted, and other formula or provisions to be able to quantify imbalances. Except for pre-existing PPAs, registration with the Market Operator will not require informing contract prices. However, generation costs shall be disclosed to the System Operator for proper implementation of the Security Constrained Economic Dispatch.
- It is expected that, as the market evolves, the duration of PPAs or contracts will shorten. When a PPA or contract ends, the generator can keep on generating and selling through signing new contracts (e.g. BPCs, new auctions for DISCOs), and through the Balancing Mechanism. It is expected that a liquid and more dynamic contract market will develop, with contract design adapted to the needs or characteristics of the parties.

5.5. New Capacity Procurement

Power procurement of new contracts for DISCOs (and eventually KE) will be through competitive processes, initially administered centrally by the Independent Auction Administrator (IAA) and/or, at a later stage, through direct competitive contracting by each DISCO, when this possibility be authorized by NEPRA, following applicable regulations and guidelines.

- DISCOs will procure power in representation of their consumers and will be regulated as last resort Suppliers to protect the interests of those consumers. The competitive process will follow NEPRA regulations as applicable and approvals for the resulting contract prices for the PPA/EPA to qualify as competitive generation tariffs and pass through as allowed power purchase cost to regulated electricity end-consumer tariffs.
- The IAA will administer auctions to procure new capacity equal to the aggregated capacity and/or energy required by each DISCO to comply with its Capacity Obligations. The IAA will use (and publish on its website) a standardized market-based Supply Contract[12] or commercial template PPA or EPA. The competitive procurement may result in one or more awarded Generators. Initially the IAA will undertake a combined procurement for all DISCOs such that each awarded Generator will sign a contract with each DISCO, proportionally to the DISCO requirement in the total energy and capacity in the auction. The IAA will not sign new PPAs/EPAs. Further details about the function of the IAA are given later in this report.
- The Competitive Suppliers, traders and BPCs (eligible consumers) will be allowed to procure power on bilaterally negotiated prices. Alternatively, they can also take the services of IAA for competitive procurement

5.6. Balancing Mechanism

The Contract Market is complemented with Balancing Mechanisms, both for Energy and Capacity, centrally administered by the Market Operator. Through these mechanisms, the Market Participants will sale or purchase of differences between contracted and actual energy and capacity of each Participant.

As part of the Market Participation Agreement, each Participant assumes the obligations to participate in the Balancing Mechanism and pay (or be paid) for imbalances. A Supplier that is a demand aggregator for a group of Eligible Consumers can assume the aggregated imbalance of all its consumers. There will be two types of balancing mechanisms as described below:

5.6.1. Balancing Mechanism for Energy (BME)

The balancing mechanism for energy (BME) is designed to cater for the imbalances that arises due to differences in the contracted energy and the actual energy generated/consumed. This mechanism will work in the following manner:

- For Demand Participants (Suppliers, BPCs that are Participants, exports), the energy imbalance will be the difference between actual energy metered and contracted values, taking due consideration of losses as explained in *Section 13* in this report.
- For Generators, and Traders selling (including imports) in the market, the energy imbalance will be the difference between scheduled energy (contracted and actual generation or imports (metered) in connection point. The BME will have no impact on Generators contracted under

[12] Supply Contracts will deal only with commercial aspects of the agreement. Aspects related to the connection to the grid will be managed through Connection Agreements signed between the Transmission Services provider and the Participant.

existing PPAs/EPAs. However, design of future contracts would incorporate the Balancing Mechanism by referring to mandatory compliance with Market Rules / Market Code.

- Efficient power plants will be dispatched as per SCED even if not contracted or not fully contracted. The non-contracted part of energy injected in the system by any power plant will be sold through the Balancing Mechanism subject to, being a Participant or being represented by a Trader or Supplier.
- Generators/power plants that are taking/extracting energy from the grid for own consumption during maintenance, outages or test periods will be considered as demand and pay the energy through the Balancing Mechanism if they have not made any alternative arrangements.
- Transmission losses above the level allowed by NEPRA in transmission tariff determination, will be bought by the transmission company at balancing prices.
- The Market Operator will calculate, for each Participant, energy imbalance prices and imbalance quantities, for each market period. The recommended balancing period for the start of the market is one hour. Later it can be moved towards shorter period as per decision of NEPRA.

5.6.2. Balancing Mechanism for Capacity:

The Balancing Mechanism for Capacity provides a mean to settle the eventual differences that may exist between the capacity demanded, the capacity contracted and capacity actually provided.

Through this mechanism, the market participants which have procured more capacity than actually demanded by their customers, can interchange such capacity with other market participants which are in the opposite situation. It will also serve to balance the situation of generators, which had contracted a certain amount of capacity (with BPCs or Suppliers) and that, due to unavailability, they would not have been able to provide it.

Demand and available Capacity will be determined for certain hours of the year which, in principle, are the hours in which the system is more stressed. At such moment, the capacity provided by each market participant will be evaluated and compared with the demand served at the same time (taken due consideration of the necessary reserves and the losses).

The participants which have a positive imbalance (provide more capacity than needed) will be credited and they can sell such surplus, or part of it, to other participants which required more capacity than their capacity available and have negative imbalances.

The Balancing Mechanism for Capacity will be executed once a year, during the two first months after the end of each fiscal year. *Section 12* of this report provide more detailed analysis of the functioning of this mechanism.

It needs to be recognized that both the Capacity Obligations and the Balancing Mechanism for Capacity are complementary instruments with similar objectives: To guarantee that there is enough capacity installed in the system to supply current and forecasted load with an adequate level of reliability. Therefore, both instruments need to be assessed jointly: i.e. Capacity Obligations can be “relaxed” if there is a relatively liquid balancing mechanism, with several Market Participants having enough capacity surplus; or the opposite if the capacity surpluses reduced.

As a result, it is not considered absolutely necessary that the Balancing Mechanism for Capacity will start at the same time the CTBCM is established. Since this mechanism is relatively complex and it will require some time to be properly developed and understood by all participants, it is considered to delay its implementation for two years after CTBCM initiation. During this period the security of supply will be guaranteed through the relatively tight capacity obligations described above.

5.7. Generation Prices

In order to meet the requirements of the regulated consumers, the Generation prices will be determined by competition, subject to provisions of the procurement regulations to be promulgated by NEPRA for CTBCM. The high-level process is as under:

- New generation capacity procurement prices for DISCOs will be the result of auctions (competitive bid tariff) to be carried out by IAA initially, subject to procurement regulations and competitive bidding regulations
- In the Balancing Mechanism for energy, prices will result from competition to generate (economic dispatch subject to system security constraints) and for capacity using reference capacity prices from reference technologies. For pre-existing PPAs/EPAs the regulated generation tariffs (determination and notification, under relevant methodology) will remain in place.
- Bulk Power Consumers (eligible consumers) can freely negotiate contract conditions and prices with generators or Competitive Suppliers. Alternatively, a BPC can agree a retail supply contract with a Competitive Supplier, where the contract commits the supplier to buying at best possible prices, through competition.

5.8. Settlement and Payment

Settlement and payment for Bilateral Contracts will be agreed bilaterally between the parties that have signed the contracts. The payments for legacy PPAs/EPAs will be managed by SPT through an amended Commercial Code.

Settlement of the centrally administered markets (balancing mechanisms and trading platforms in future) will be a function of the Market Operator. Payments will be among Participants based on the settlement statement prepared by the Market Operator. Purchase and sale of imbalances will be among the Participants, and therefore, not involve liabilities for the Market Operator. There will be centralized payment system backed by credit covers implemented by the MO for the payment of imbalances.

5.9. Security Cover Mechanism

The counter party credit risk is very important aspect of the competitive markets. Considering the non-payment culture in Pakistan, this aspect has been thoroughly analysed to mitigate this risk. The market will include security cover mechanism to address wholesale non-payment risks, based on the following principles:

- The proposed market design will create incentives for wholesale payment culture. Similarly, as DISCOs and KE expect and require consumers to pay their bills, they as retail suppliers, should also pay their wholesale costs (generation and transmission) that provide the energy allowing them to supply and sell to their consumers. Without wholesale purchases, the DISCOs and KE would not be able to sell.

- The non or late payment of DISCOs or KE as last resort suppliers will receive the same treatment as non or late payment by the Competitive Suppliers supplying to eligible consumers (BPCs). Similarly, the contracting requirements and Capacity Obligations of Competitive Supplier also apply to each DISCO in its role as Last Resort Supplier. This means that all suppliers including last resort suppliers will provide credit covers for the centrally administered markets run by the Market Operator.
- A credit cover mechanism, to the extent feasible, will also be introduced for bilateral payment to generators by DISCOs to move away from the sovereign guarantees. Each market-based Supply Contract/PPA/EPA of DISCO will include provisions in case of non-payment (default to the contract) and required credit cover.
- The financial health of each DISCO will be carried out in assistance from IAA to determine their credit worthiness and the ability of the DISCO to provide the required credit cover from its own resources. If a DISCO is not credit worthy to provide the credit cover, the mechanism described through the IAA will provide support (Government support for low performing DISCOs owned by GoP). The IAA and DISCOs will collaborate to complete this analysis and arrange the required guarantees.
- The Generator will be able to call the default of a contract in case of non-payment (as per agreed terms and conditions in bilateral agreement between the parties) and continue to sell through the Balancing Mechanism until signing another contract. If the contract is with a DISCO, the DISCO will result buying in the Balancing Mechanism.
- Each Participant must provide credit coverage for their expected exposure to imbalances (either energy imbalances or for the expected results on the balancing mechanism for capacity). The market operator will devise a methodology to calculate the credit cover for each participant and will implement it in its management system.
- Purchase and sale of imbalances will be among the Participants, and therefore not involve liabilities for the Market Operator. However, it will be the Market Operator responsibility to ensure that all provide sufficient security coverage for imbalances. This will be a condition for the admission as market participants.

5.10. EVOLUTION OF THE MARKET

Upon maturity in the market, in the future, the Market Operator may implement and administer a centralized medium and short-term *power procurement platform* for uncontracted generation for competitive short-term procurement by last resort suppliers, BPCs or other Competitive Suppliers or Traders. The participation is such market will also be subject to provision of the credit covers. Through this platform, the DISCOs and KE will be able to trade their surplus/deficit under short and medium terms contracts.

6. PRODUCTS TRADED IN THE MARKET

Any market is characterized by the type of products traded in such market. The wholesale electricity market design (CTBCM) defines two products that will be traded (bought and sold) in the market:

- **Energy** to sell production or imports injected to the grid, and to cover consumption of the demand (and exports).
  - The physical product "energy" is a result of the generation (and imports) instructed by the System Operator through centralized economic dispatch within system security constraints and real time operation, and the actual consumption extracted from the grid by consumers (and exports) plus, when and as applicable, load shedding and demand management in shortages conditions as instructed by the System Operator and/or administered by the distribution company as distribution system operator. Therefore, the physical product is not controllable through contractual arrangements.
  - The energy price is normally related to specific energy quantities/volume (the contracted energy) so that the purchaser (demand) can manage the generation purchase costs and the seller (generation) can manage the revenues from the sold energy. The market is the environment where purchaser and sellers can manage energy price risks, mainly through the Contract Market.
  - The energy contracted can be a predetermined volume, profiled in different ways, however the contracts must include clauses or formulas to establish commitments consistent with the trading period established in the Market Code.
  - As already mentioned, that the energy is the result of the centralized dispatch and is not controllable by contracts, and there will always be imbalances, which will be settled by Market Operator on Marginal Prices (discussed later).
- **Capacity**. The Generator (the seller) sells its available or committed generation capacity, and the purchaser purchases capacity to cover its capacity obligations. The purchasers are Participants that represent consumers (resell to) or are consumers (demand participants). It is, therefore, a market product linked to physical generation assets (for available or committed generation capacity) and to the peak demand. Both can be managed by the relevant Participants: the Generator through adequate maintenance, fuel availability and reducing or controlling outages; and the demand through efficient electricity tariffs and demand side management. In summary, while the physical product energy generated is under the control of the System Operator, the physical product capacity for a Generator is under its own control. The target is that a generator is paid for being available and the demand pays for having available the capacity that it needs to ensure that the demand will be supplied. The fact that a plant or a unit was built and entered commercial operation by itself is not enough to get the capacity payment, it must also be available.
  - The trading product is created by the capacity obligations imposed on demand participants in the market design. This obligation, which represents and has the purpose of each demand to contribute to the system security of supply, obliges the demand participant to purchase capacity and, therefore, creates the market for generators to sell their capacity (if available).

- The Firm Capacity of each type of technology will be a certified product and a certification mechanism will be established to issue certificates subject to performance standards which will be traded in the market to meet the capacity obligations.

It is important to take into consideration the difference between the two market trading products, as this will be reflected in the contract design and provisions.

For the investor in generation, a capacity payment that is independent of energy actually produced is a way to cover the risk of not being dispatched that exists in an energy only contract. On the other side, for a demand, to purchase capacity (and pay for it) is a way to cover its supply needs having secured through the contract that the generator will supply regardless the conditions in the market. In the case of Pakistan, in the proposed competitive wholesale electricity market, the demand must purchase capacity (and pay for it) to cover the capacity obligations that are part of the same market design, and while ensuring that the demand will be able to supply its needs, it also will contribute to the system security of supply. In summary, the product capacity can be characterized as the generation contribution to the security of supply of the buyer and of the system. In some markets, this reliability or security of supply requirement included as part of the capacity product in contracts may include provisions in the contract for the seller to pay the buyer in case of not complying with contracted available capacity and as a consequence of it, the demand cannot supply its load (load shedding) or is subject to penalties for noncompliance with capacity obligations. In other words, the Generator has to compensate the buyer if it is not available during shortage periods.[13] The performance of generators will be constantly monitored and reported by the System Operator, and in case of low or non-performance, the capacity certificate will be revised or cancelled.

[13] Other more sophisticated reliability products have been developed in electricity markets, but only as a later stage of market development.

7. BALANCING PERIODS

The balancing period is the trading interval in which imbalance quantities and imbalance prices are determined. The balancing period may be hourly, several hours (e.g. peak and off peak), daily, weekly or even longer. The duration of the balancing period is justified and decided based on the nature of the product traded. The duration of the balancing period will be established in the Market Code and can be modified as the market develops (typically, moving to shorter periods in the energy balancing although not necessarily in the capacity balancing) through an amendment to the Market Code, following the review and justification process and approval of the amendment by the regulator.

- As energy varies often, the energy balancing period shall be hourly at the start of the market and can be moved to more shorter periods at later stages depending on the conditions in the market. In the description and examples later in this document, the assumption is an energy balancing period of one hour, except if the report explicitly says otherwise.
- As capacity is associated to peak demand and generation availability, the capacity balancing period shall be longer. In the case of Pakistan, load is remarkably seasonal. Higher load levels occur in summer (between June and September) which are, in average, more than 30% higher than in the rest of the year. It is during these months in which the system is more stressed, and security of supply needs to be guaranteed. Availability and capacity obligations needs to be checked during such period and, as a result, the Balancing Mechanism for Capacity can only be performed on yearly basis.

As the market develops, participants build knowledge and expertise, and the infrastructure and systems strengthen the market maturity, the balancing periods for energy can be reduced allowing and promoting more dynamic response and behaviour of the Participants.

8. CONTRACT MARKET: DESIGN OF NEW MARKET CONTRACTS

8.1. GENERAL CONSIDERATIONS

Contracts are the instruments to manage risks. In an electricity market, the first environment for the buying and selling of electricity is the Contract Market. The purpose of the Contract Market is for a company participating in the market to be able to manage its risks and share risks among those that can best manage them. Risks to be managed by a generator include ensuring a steady or predictable cash flow; and for a demand reducing volatility and stabilize power purchase price and ensuring security of supply.

Contracting energy and capacity are the market instruments to manage and share energy risks. Different contracts designs allow different allocation of risks. However, in a market with multiple buyers and multiple sellers, the contracted energy (the energy market product) may be different than actual consumption or requirements of the demand/buyer, or actual energy generated by the generation/seller. Therefore, the market includes a trading environment to clear energy differences (imbalances) between the physical and the market energy product, to ensure that each Participant extracting energy from the grid pays for all that energy (through contracts and balancing) but not more, and that each Participant injecting energy to the grid is paid for all that energy but not more.

Regarding capacity, the Contract Market is the environment to cover the capacity obligations of demand participants. The characteristics of the contracted capacity is similar in all contract designs presented in this document, except on how the capacity quantity is defined. However, for each demand participant the contracted capacity may result different to its capacity obligation, and for each participant that is or represents generation the capacity committed in contracts may be different to its available capacity. Therefore, the market will include a trading environment to clear capacity differences (imbalances), to ensure that each demand Participant buys its capacity obligation and each generation complies with its contracted capacity commitment.

Considering that the interest of a Participant is to manage the risk of price volatility, revenue certainty and manage imbalances, the contract market needs to allow and enable sufficient flexibility on how Participants agree to trade bilaterally (agree quantities and prices, and conditions). Therefore, the contract designs should be tailored to reflect the needs and conditions of different load profiles (the buyers in the contract market) and of different generation technologies (the sellers in the contract market). In this section, based on international experiences, different types of contracts can be allowed. The variety of designs will allow each Participant to choose the preferred contract design(s) and contract portfolio to optimize the needs, conditionality and interests of the Participant.

8.2. CONTRACTED PRODUCTS

In all kind of contracts, it shall be recognized that:

- It is possible to buy or sell energy only, capacity only, or two products (energy and capacity);
- Contracted energy can be defined as fixed quantities (with hourly profiles), or with formula to calculate the hourly quantities, or as a percentage of energy in commercial settlement metering systems. (The energy balancing period assumed in this document is one hour.)

- Contracted capacity can be defined as fixed quantities (annual or monthly), or a formula to calculate the capacity quantities, or a percentage of available generation capacity, or a percentage of the demand capacity obligation that a demand participant is required to cover with contracts or buy shortfall in the capacity balancing mechanism.
- Price of energy and of capacity will depend on risk assigned to each party and associated costs.

It is important to emphasize that, independent of the contract design and portfolio selected, a Participant may result with energy or capacity imbalances;

- A Buyer in the contract market may result with differences between contracted quantities (energy and capacity) and actual demand or capacity obligation (e.g. in the case of suppliers, energy taken from the grid to sell to its customers or capacity obligation of the demand it represents or covers).
- As the competitive electricity market for Pakistan is based on a centralized economic dispatch within system security constraints, a generator selling energy in contract(s) may result not being dispatched, for economic reasons or due to system constraints. The situation may be different for renewable generation that has priority dispatch, but that cannot control energy generated as this is variable depending on weather conditions (beyond the control of the generation company).

Therefore, it is necessary to quantify / measure the imbalances between what a Participant has contracted (and has to pay or to be paid) and the actual demand or generation.[14]

The standard requirement in electricity markets is that each contract should clearly establish the contracted quantity / quantities (either absolute values or formulas) for each balancing period[15] where imbalances between contracted and actual quantities are metered, priced and cleared.

In electricity markets where contracts can be two part (energy and capacity), imbalances may arise with the contracted energy or the contracted capacity. Therefore, mechanisms are implemented to clear the differences, such as the Balancing Mechanism for Energy (BME) and the Balancing Mechanism for Capacity (BMC) as described in this report.

To calculate and settle imbalances, each Participant[16] is obliged to submit the information on any new contract or a modification to an existing contract to the Market Operator, to be included in the **Contract Register**. The Market Operator will administer the Contract Register to verify that all requirements have been complied, prior to approving the registration. Only contracts that have valid registration in the Contract Register will be considered in the calculation and settlement of imbalances, using for such purpose the information submitted by the parties during the registration.

Additionally, there is a need to **calculate and allocate the quantity and costs of losses.** Losses are calculated as the difference between the energy injected to the grid at the Common Delivery Points (where the commercial revenue meters are installed) and the energy extracted (bought by the demand participating in the market or for exports), also at Common Delivery Points (CDP). The standard practice

[14] In addition, and equally important, energy spot or balancing pricing should provide economic signals for efficiency both for generation and for consumption.

[15] Even when a Participant may not have an imbalance as per the type of contract, e.g. a Buyer in a Load Following Contract, the Balancing Period is used to calculate the imbalance of the other party to the contract. This is explained further in the description of each type of contract.

[16] Details to be developed in Market Code or other regulations or procedures for the market will include whether, to accept the request for registration, both parties in the contract must submit the information, or if only one party can submit the information subject to the other party confirming that it accepts the information sent by the other party.

is for the demand to pay for losses, for all the actual losses or the capped losses that the regulator sets for the network companies. This aspect is also discussed in this document.

The following section describes different type of contracts that could be useful for the electricity market in Pakistan at the commencement of CTBCM. It is important to note that each design represents a different allocation and sharing of risks. Therefore, taking into consideration the cost of risk management, may result in different prices. The proposal is to allow these types of contracts to ensure flexibility in the contract market. When or whether a type of contract will be required or be used by a Participant will be a result of Participants' requirements and decisions in the future.

Note 1: It shall be noted that the actual contracts bilaterally agreed among participants may be different and they do not, necessarily, fit in any of the categories described below, which should be considered only examples. In any case, any type of contract can be registered by the Market Operator provided that:

- It does not have clauses which imply self-dispatch; and
- The energy and capacity traded between the participants can be clearly identified. This is required to settle the contract without any kind of doubt or special interpretation

Note 2: For simplicity, examples in this document refer mostly to DISCOs (as Last Resort Suppliers). However, the same assessment and conclusions can be extended to include Bulk Power Consumers or other Competitive Suppliers (demand) and Traders.

8.3. Generation Following Supply Contract

In a Generation Following Supply Contract design, the Seller sells the energy generated and injected to the grid (at its CDP) and the Buyer buys and extracts at its CDP all or a share of the energy injected by the Seller. In this type of contract, energy product follows the physical energy of the generation. The Seller's energy payment from the contract is based on what the seller has generated and the contract price.

This design is appropriate for non-controllable generation: renewable generation that cannot be dispatched (such as solar, wind, small hydro run of river) and selling only energy that they generate (without prior fixed commitments). In principle, it can have similarities with current EPA design in Pakistan.

If a Generation Following Supply Contract includes obligations regarding available capacity in addition to the contracted energy, the design of the existing PPAs in Pakistan (pre-CTBCM) can be assimilated to this type of market contract design.

In summary, this type of contract can be very useful to accommodate existing EPAs/PPAs in the CTBCM to become multiple contracts between a generator and different buyers (only commercial allocation is considered here).

8.3.1. Contracted Energy in a Generation Following Supply Contract

If the Generator has a single Generation Following Supply Contract selling all its energy, the contract is between the Generator and one Buyer, and the Buyer purchases 100% of the energy injected by the Seller, and the Seller cannot sell in contracts its production to any other Buyer. This is partly similar to a PPA or EPA that establishes exclusivity, for example in a Single Buyer market.

The current practice in Pakistan is different to a Single Buyer (in essence), as each PPA or EPA has been signed by CPPA-G (or CPPA of NTDC or WPPO) in representation of DISCOs and KE and, therefore, contracted energy is bought and should be paid by each and all DISCOs and KE (for the share that it procures through CPPA-G) based on energy actually delivered to that DISCOs and KE (a resulting of system dispatch and real time operation).

In the electricity market, the Generation Following Supply Contract also allows a Generator to sell to several Buyers, each with a bilateral contract, by establishing in the contract that contracted energy is a share (a percentage) of the energy injected by the Generator on an hourly basis. With such a design, the Generator may have several contracts, each one defining the percentage of the energy generated/injected by the Generator allocated to Buyer, subject to that the total sold is not greater than 100% (the Generator cannot sell in this contract design more than energy generated).

The percentage / share can be defined in the contract provisions as a number, or as a formula to calculate the percentage. If the contract is long term (duration several years), eventually the contract can establish that the percentage or the formula for its calculation will be reviewed after a number of years (e.g. every 2-5 years) and modified through a methodology established in the contract or mutually agreed.

The role of the Market Operator in administering the Contract Market will include, among others, the verification that the total percentage sold by a Generator in this contract design is not greater than 100%. Any Generation Following new supply contract or modification will be rejected by the Market Operator if the total energy sold in this type of contracts (based on the information in the Contract Register) adds a percentage greater than 100%.

For the Generator (the seller), a Generation Following Supply Contract ensures that it will not have a negative energy imbalance and protects from having to buy in the Balancing Mechanism for Energy (BME). The seller never has a negative energy imbalance in this type of contract as the product sold is based on actual generation. If a Generator is selling only with Generation Following supply contracts and the total of the percentages sold in those contracts is less than 100%, the remaining non-contracted energy will be sold in the Balancing Mechanism for Energy.[17] If instead the total is 100%, all energy would be sold in contracts and the Generator would not have any trading in the balancing mechanism for energy.

For a demand (the Buyer), a Generation Following Supply Contract establishes the price but exposes to quantity imbalances and prices in the Balancing Mechanism for Energy. Each hour, the contracted energy is the percentage of the actual energy generated by the seller established in the contract, independent of the Buyer’s consumption during the same period. However, under the centralized economic dispatch for generation, the energy generated by a Generator does not follow the profile of the consumption of each buyer or of the total power system (generation may increase when demand decreases, an/or decrease when demand increases), the Buyer will result with imbalances between the contracted energy (i.e. the percentage of the energy actually generated/injected by the seller) and the actual consumption of the Buyer measured at the corresponding (one or more) common delivery points (CDPs) with the commercial

[17] Similarly, a Supplier that buys from several generators in Generation Following design, can resell to the demand also with a Generation Following design, although in this case the share will correspond to the percentage of the total energy injected by the generation contracted by the Supplier. In other words, the contract can be used to follow and resell the energy of a group of power plants.

settlement metering system[18]. Therefore, the BME applies to the Buyer that may have imbalances between contracted energy and actual consumption (buys or sells in the BME).

Indicative Example: A Generator sells with Generation Following supply contracts all its energy to two DISCOs (as suppliers), 40% of the generated energy to DISCO 1, and 60% to DISCO 2, and this is the only contract of each DISCO. The Generators will be dispatched by System Operator as per procedures defined in the Grid Code for Security Constrained Economic Dispatch (SCED). Therefore, the generator owner will not be in the control of the dispatch of the Generator.

For a certain Balancing Period (one hour) when the Generator generates / injects 200 MWh as per instructions from the System Operator, there would be the following results:

- Generator: No energy imbalance as 100% of the energy generated is sold in contracts.
- DISCO 1: is buying as contracted energy 40% of the generated energy, i.e. 80 MWh.
  - If during this Balancing Period (one hour) the DISCO 1 has taken 90 MWh from the grid (more than energy contracted), it will have a negative energy imbalance. For that hour, the DISCO buys 80 MWh from the Generator at the contract price, and 10 MWh from the BME at the BME price during this Balancing Period.
- DISCO 2: is buying as contracted energy for this hour 120 MWh and has to pay for the 120 MWh to the Generator at the contract price.
  - If during the hour, DISCO 1 has taken 110 MWh from the grid (less than energy contracted), it will have a positive energy imbalance. For that hour, the DISCO buys 120 MWh from the Generator at the contract price and sells in the BME the surplus 10 MWh at the BME price during this hour.

BME: the balance of the BME is zero, provided that the two discos one purchased in excess and the other in defect, and the Generator, as per the generation following supply contract has zero deviation.

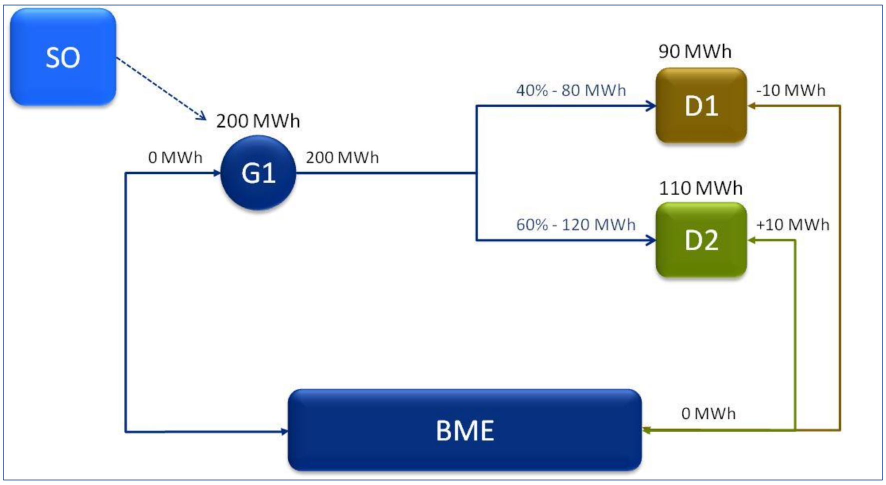


Figure 1 - Generation Following Supply Contract

[18] As described in this report, the transmission losses will be added as an uplift. This applies to all quantities metered at demand CDP.

However, in real markets normally there are multiple sellers and multiple buyers, so, the following chart depicts schematically how in this case the Generation Following contract works:

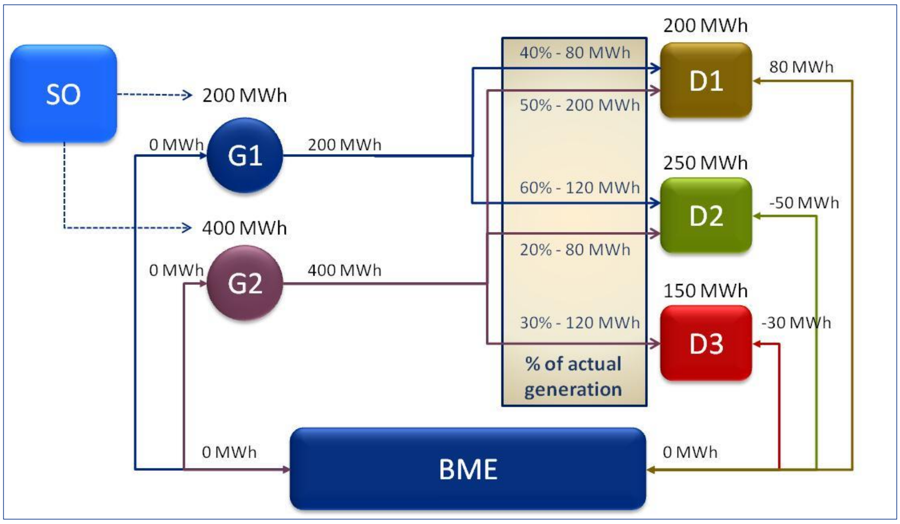


Figure 2 - Multiple Sellers/Buyers Generation Following Supply Contracts

This contract design allocates the energy risk (quantity and demand profile) to the buyer. However, it must be said, that in principle the Buyer has good knowledge of its forecasted demand and may have mechanisms to control or manage its load. Also, a portfolio of contracts will be available with the buyer to manage this risk.

The seller (generation) faces no imbalances risk. However, the contract assigns to the Generator the availability and dispatch risk. If the contract is designed and agreed to sell only energy, the revenues of the Generator will depend on its actual production. The Buyers will only buy and pay the Generator if energy is actually generated and injected into the Grid.

Energy contract price tends to correspond to generation variable cost (for thermal in a two-part contract) or the energized fixed costs for a renewable generation. However, variations occur in competitive markets where some fixed cost can also be made part of the energy costs.

Note: In non-competitive electricity markets, some purchase agreements may include a provision on take-or-pay of energy[19]. This provision is usually interpreted as priority dispatch to ensure energy generated (typically, on annual basis) is not less than this volume and minimize the risk of payment for the shortfall between actual and take or pay energy. In general, energy take-or-pay provisions are discouraged as contrary to competition and least cost use of generation resources and may not be allowed to be explicitly included in new contracts in competitive electricity markets. In the market, for the transition and administration of pre-existing purchase agreements, the take or pay can be considered in the economic

[19] For thermal generation, take-or-pay in traditional PPAs have been used to replicate the take-or-pay fuel purchase commitment of the generator (e.g. natural gas or LNG). However, the cost of the fuel commitment can also be administered as part of the fixed costs in the capacity price.

dispatch with zero variable cost (it has to be paid even if not generated) and therefore would be included as energy generated in the Generation Following design.

8.3.2. Contracted Capacity in Generation Following Supply Contracts

A Generator (Supplier/Trader that represents generation) can sign one or more Generation Following supply contracts with a Buyer(s) that represents or is a demand:

- Each contract will define the contracted capacity as a share of actual available generation capacity. The issues and constraints regarding percentages are similar as those described for energy. The Generator (the seller) cannot sell more than 100% of its available generation capacity.
- If the Generator sells actual available capacity without a commitment, the security of supply risk would be partly transferred to the Buyer in that case. However, eventually the contract could establish a commitment to an annual or monthly minimum availability, and paying the buyer a compensation should actual availability be less than the minimum established as commitment in the contract.

Note: For pre-existing PPAs with take-or-pay energy quantities in Pakistan, it could be said that the minimum annual guaranteed energy can or has been converted into some kind of capacity payment (take or pay) with availability obligations for the Generator and penalties if this availability is not achieved. The energy generated is in any case "generation following" (a percentage of the actually generated energy).

In any case, for the market perspective, these take or pay clauses, as well as availability obligations should have no influence for balancing purposes. The energy balancing should be carried out as if these take or pay clauses do not exist[20]. For the capacity, all the availability risks are taken by the buyer and therefore, it is the buyer which may be exposed to the Balancing Mechanism for Capacity[21]. However, the cost of the take-or-pay provisions has not been incorporated into the capacity price.

8.3.3. Example of TWO-PART Generation Following Supply Contract with Multiple Buyers

This example considers a Generator that is 100 % contracted with two DISCOs, for energy and capacity using Generation Following design. DISCO 1 contracts 60% and DISCO 2 contracts 40%.

The Generator has 100 MW available capacity and has produced/injected to the grid at its CDP 40,000 MWh in a month.

- The Generator's revenues will result from quantities, prices and conditions in the contracts. The Generator will invoice the DISCOs as follows:
  - To the DISCO 1, an invoice including the capacity payment of 60 MW (60% of 100 MW) at the capacity price in the bilateral contract, plus the energy payment of 24,000 MWh at the energy price(s) in the bilateral contract with DISCO 1.

[20] Take or pay clauses, however, may have influence in the System Operator dispatch, since this may act as restrictions in the SCED.

[21] The penalties for low availability which may be included in the contract shall be considered a bilateral transaction without reflecting them in the market calculations.

    - To the DISCO 2, an invoice including the capacity payment of 40 MW (40% of 100 MW) at the capacity price in the bilateral contract, plus an energy payment of 16,000 MWh at the energy price(s) in the bilateral contract with DISCO 2.
    - <u>If the contract includes commitment to security of supply</u>, the Buyer will receive in the invoice a discount as a compensation (or Liquidated Damages) should actual available capacity be less than the minimum availability commitment in the contract. The compensation payment to each DISCO would be calculated based on the shortfall in committed availability. For ease of implementation and to avoid disputes delaying payment of compensation, the invoice of the Generator will include payment for energy and for capacity minus compensation (as applicable). In summary, the invoice will already incorporate the discount for failure to deliver availability commitment.
- On the other side, the DISCO 1 that is buying 60% of the generated energy and available capacity will have to pay for it to the Generator (according to the terms of the contract), and, also, it will participate in the BME:
    - At the end of the month, the net result of hourly energy imbalances is determined totalling for each hour of the month the energy imbalance (positive or negative) at the BME price (hourly energy imbalances, as described before, calculated as the difference between the contracted energy and the energy actually taken from the grid, and valued at BME hourly price). If the monthly net result is negative, the DISCO 1 pays to the market the monthly energy imbalance amount. If instead the net monthly result is positive, the DISCO 1 will be paid the monthly energy imbalance amount by the market.
    - At the end of the year, pay or receive from the BMC the difference between the contracted capacity and the actual demanded capacity (the capacity obligation) at the BMC price, depending on whether the difference is positive or negative as per the process described in *Section 12* of this report.
- The DISCO 2 that is buying 40% of the generated energy and available capacity will have to pay for it to the Generator (according to the terms of the contract), and will also participate in the BME:
    - At the end of the month, the net result of hourly energy imbalances is determined totalling for each hour of the month the energy imbalance (positive or negative) at the BME price (hourly energy imbalances, as described before, calculated as the difference between the contracted energy and the energy actually taken from the grid, and valued at BME hourly price). If the monthly net result is negative, the DISCO 2 pays to the market the monthly energy imbalance amount. If instead the net monthly result is positive, the DISCO 2 will be paid the monthly energy imbalance amount.
    - At the end of the year, pay to the market if the capacity imbalance is negative or be paid / receive from the market if the capacity imbalance is positive the difference between the contracted capacity and the actual demanded capacity (the capacity obligation) at the BMC price.

8.4. LOAD FOLLOWING SUPPLY CONTRACTS

In a "Load Following" supply contract, the Buyer contracts with the Seller:

- a share (a percentage) of the Buyer's energy actually taken from the grid (as measured based on the settlement metering systems at the corresponding CDPs of the Buyer). The Seller is paid based on actual measured energy of the Buyer, independent on actual energy generated by the Seller.
- a share (a percentage) of the Buyer's peak demand (as measured based on the settlement metering systems at the corresponding CDPs of the Buyer). The Seller is paid based on actual capacity demand of the Buyer, independent on actual capacity made available by the Seller.
- If the buyer contracts 100% of energy and capacity requirements in this type of contract, then it will never be exposed to imbalances in the balancing mechanisms. Any eventual imbalance (either in energy or capacity) shall be assigned to the seller,

This type of contracts could be appropriate for Bulk Power Consumers that want to be fully covered by contract pricing and avoid the cost or risk of imbalances.

8.4.1. ENERGY IN LOAD FOLLOWING SUPPLY CONTRACTS

The energy contracted is defined as a share (percentage) of the energy taken from the grid by the Buyer at its CDPs (totalling energy metered at all its CDPs, if more than one CDP). As described before, the contracted energy must be defined for each energy balancing period (e.g. an hourly basis). The share is established in this type of contract as a fixed percentage, or a formula to calculate the percentage. The Buyer can be a DISCO or KE, or a Bulk Power Consumer (BPC) or a retail Supplier reselling to demand.

As all generation is subject to centralized economic dispatch or must run for non-controllable renewable generation subject to provisions of the Grid Code, the generation of the Seller will not follow the demand shape of the Buyer(s) and there will be differences / imbalances between what the seller is generating and what the Buyer is taking from the grid.

If the Buyer agrees a Load Following supply contract with a single generator, the share could be 100%. If the share is less than 100%, the remaining non-contracted energy taken from the grid will be bought in the BME at marginal price.

If the Buyer buys from more than one generator, each with a Load Following supply contract, the percentage in each contract defines how the load profiles of the Buyer is distributed among the contracts. If the aggregated percentage of contracted energy is less than 100%, the remaining non-contracted demand will be bought in the BME at marginal price.

Indicative example: A Bulk Power Consumer has covered fully its demand with two Load Following supply contracts, one with Genco 1 for 40% of its demand profile (energy metered at its CDPs) and another with Genco 2 for 60%.

- In an hour, the BPC consumes 50 MWh, all covered in contracts. Therefore, the BPC has no energy imbalance and no settlement of imbalances in the BME.

- Genco 1: During this hour the contracted energy is 20 MWh (i.e. 40% of the actual energy taken from the grid by the BPC during that hour), measured by the commercial and settlement metering system and procedures.
  - The Buyer owes / buys from Genco 1 20 MWh at the contract energy price;
  - If Genco 1 generates during that hour 27 MWh (and the Generator has only one contract, the contract with the BPC), it is generating more than the contract, thus is selling the difference, i.e. +7 MWh in the BME at the BME Price
- Genco 2: during this hour, the contracted energy is 30 MWh
  - The Buyer owes / buys from Genco 2, 30 MWh at the contract energy price;
  - If Genco 2 generates during that hour 23 MWh (and the Generator has only one contract, the contract with the BPC), it has to purchase the difference (shortfall) i.e. -7MWh, in the BME at the BME price

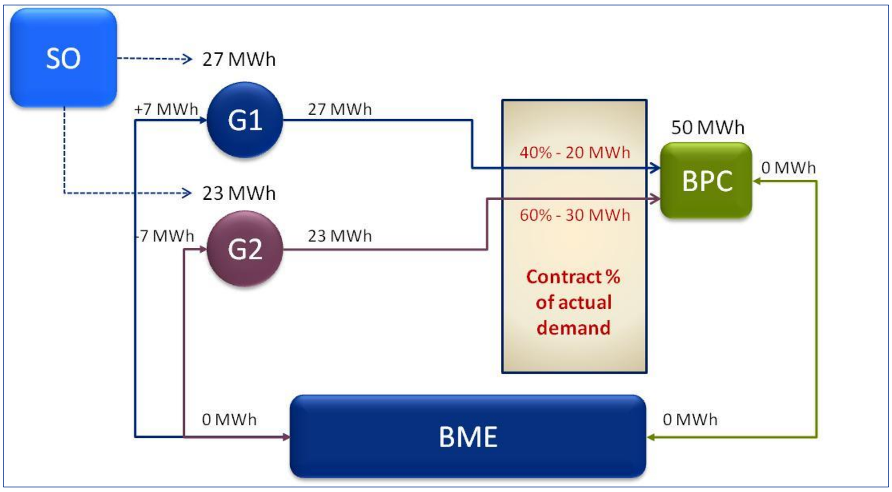


Figure 3 - Load Following Supply Contract

In summary, this contract design allocates the demand risk (demand quantity and demand profile) to the generator(s) that is the seller. The Buyer faces no demand or market risks as long as 100% contracted with Load Following design.

Considerations on monthly net energy balancing amount and settlement are similar to the description for the Generation Following contracts.

The following chart depicts the Load Following Contract with multiple sellers and multiple buyers:

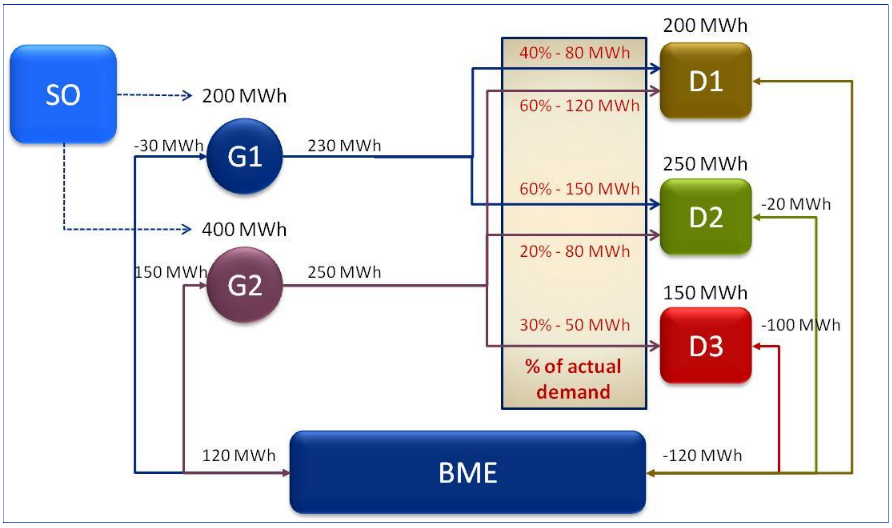


Figure 4 - Load Following Supply Contract with Multiple Sellers and Buyers

8.4.2. Capacity in Load Following Contract

The contract may include a capacity payment that can be designed replicating the demand capacity coverage required as capacity obligations of the Buyer. In this arrangement, the seller will be responsible for the capacity obligations of the buyer.

Other considerations on capacity balancing and settlement are similar as to the Generation Following supply contracts. The capacity imbalance for the Generator (the Seller) will be calculated as available capacity minus total capacity sold in contracts.

8.5. Capacity and Associated Energy Supply Contracts

This contract has also a "load following" design but the energy is linked to covering the capacity requirements (capacity obligation) of the Buyer. Therefore, it is appropriate for any demand Participant, in particular a DISCO, that wants to fully cover its capacity obligation via a contract with a Generator (or Supplier) that also commits to energy sale and energy pricing. In this design, the Buyer (as a demand) benefits from complying partly or fully with its capacity obligation and at the same time stabilizing energy purchase price.

The main component of the contract is the capacity obligation assumed by the Generator. The Generator commits to a capacity availability (that may be profiled during the months or weeks of the year, for the generator to consider and manage maintenance outages plans or other outages). The Buyer buys and pays for capacity in the contract only the available capacity of the Seller up to the contracted quantity. The contract may have provision for the Generator to pay a compensation to the Buyer in case of failing to provide the committed available capacity during a period where there are shortages and load shedding that affects the Buyer (or the consumers to whom the Buyer resells energy) The purpose is to promote adequate maintenance and availability of generation to avoid maintenance outages in periods with lower reserves and optimize generation maintenance outages when expected reserves are high.

The contracted energy is shaped with the demand profile of the Buyer. As in the previous design, the actual energy generated (the physical generation) is disconnected from the contracted quantity, and the contract becomes a risk management of security of supply and financial instrument to set energy and capacity prices in advance.

8.6. Financial Supply Contract with Fixed Quantities

In a fixed quantity supply contract, the buyer and seller agree in advance, fixed amounts of energy and capacity to be supplied by the seller and purchased by the buyer irrespective of the actual generation and consumption. This contract is designed to share risks between the two parties in the contract. This contract is financial in nature, the obligation of the seller is to supply, but not to generate, and the obligation of the buyer is to pay, not to consume.

Energy: The contract commits to an energy schedule in advance (energy quantities defined for each balancing period, for example one hour).

- Each balancing period, the generator sells to the Buyer the energy quantity defined by the contract for this period, at the energy contract price. This is independent of whether the Seller (the generator or Supplier/Trader aggregating different generation) generates/injects more or less than the contracted energy quantity (or does not generate) during that period. If the generator is generating more than the contracted energy, the difference is sold in the BME at the price during this period. If it produces less, then the generator has to buy the difference in the BME.
- Each balancing period, the Buyer buys the contracted energy for this period at the contract energy price. This is independent on whether the energy taken by the Buyer at its CDP(s) is greater or less than the contracted energy. If the Buyer takes from the grid (totaling settlement metering systems in its one or more CDPs) more than the contracted amount, the difference is bought in the BME at the price for that period. If instead it is less, the Buyer sells the surplus in the BME.

This contract design totally disconnects contracted quantities from physical quantities generated and demanded. Therefore, contractual agreements can be made to set prices and manage risks, while maintaining an economic dispatch that ensures efficient use of energy resources (generators are dispatched according to their efficiency, i.e. position in the merit order list, regardless the contracts the generators have committed with the buyers).

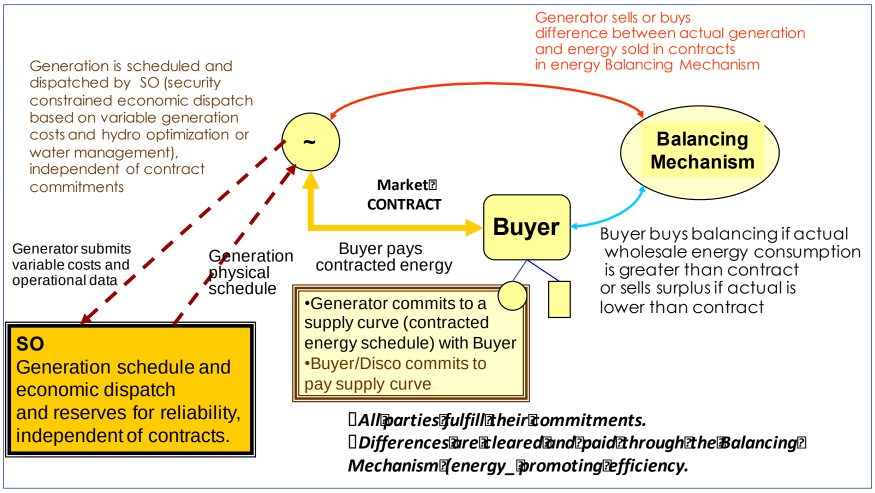


Figure 5 - Financial Supply Contract with Fixed Quantities

Note: In practice, it is expected that a Buyer may have more than one contract and the energy imbalance is calculated as the difference between total contracted energy and actual metered energy taken from the grid.

Capacity: The contract can also include the buying and selling of capacity. The general considerations on capacity product in the market applies. The contracted capacity can be defined as a number or a formula. In principle, there is no relationship between the contracted capacity and the energy volumes contracted. However, for commercial reasons, as it is very difficult to price and contract them separately, so in majority of transactions, these are contracted jointly.

For the Buyer the contracted capacity serves to cover capacity obligations of demand participants, while for the Seller it establishes the commitment to make the generation capacity available. Therefore, the contract must identify the power plants included to deliver the capacity commitment.

8.6.1. Results for a Generator (the Seller)

Energy: The generator benefits of the contract in ensuring a cash flow (contracted energy at contracted energy price) independent of whether it generates or not. However, the contracted quantities become a “demand” for the generator that must be bought in the BME if not covered by its own generation. If, instead, actual generation is greater than contracted energy the surplus is sold in the BME, and the generator’s revenue will be the contract payments plus the sale of non-contracted energy in the BME. The main risk for the generator is not being available to cover the energy contract quantity at the time when reserves in the market are low and therefore BME prices are high.

In summary:

- Generator energy revenues: contracted energy at contract price plus sales in Balancing Mechanism if actual generation is greater than contracted energy.
- Generator income from energy sale: energy revenues, as defined in the previous bullet, minus variable generation costs for energy actually generated, minus purchases in the BME if energy generated is less that its contracted demand).
- Similar to the previous design, this type of contact promotes efficient availability and variable costs of generation, as such efficiency maximizes its results and profitability.

However, it is important to note and emphasize that the efficiency incentives and the effective implementation of this type of contract requires ensuring a transparent economic dispatch, and therefore requires the credibility of the System Operator and the adequacy of its operational planning, generation scheduling and dispatch tools.

If the generator is available, it will be dispatched unless it is not economical (according to the centralized economic dispatch), in which case there is cheaper generation available in the pool than its own variable costs and therefore purchasing the shortfall to cover the contracted energy will be at a lower cost than its own variable generation cost. On the other hand, generating more than contracted would be a result of the dispatch and therefore the balancing energy price will be the same or greater than the generator’s variable costs, resulting the selling in the BME in an extra profit for the generator (although this extra profit maybe marginal, always acts as an incentive to be available and dispatched when the prices in the BME are increasing, what means that all cheaper available generators are already dispatched).

If the contract includes also the selling of capacity, the Generation (Seller) will receive also a capacity payment subject to availability (depending on the terms of the contracts). The design of the capacity quantity, conditions and settlement principle would be similar as for other contract designs described previously.

Indicative example: A Generator with two Financial Contracts with fixed energy quantities – one contract with a DISCO and one contract with a BPC -, the graph below show hourly energy results (buying and selling):

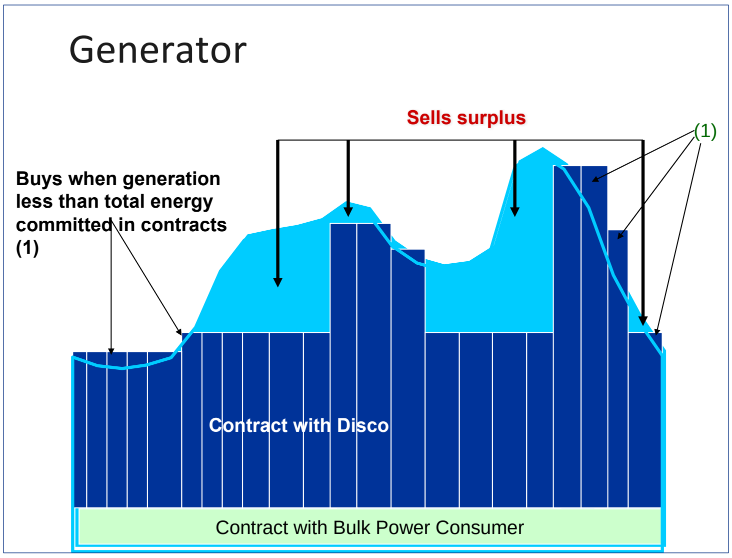


Figure 6 - Financial Contract results on the Buyer's side

8.6.2. Results for a Demand (the Buyer)

The Buyer benefits from covering its capacity obligations and from having predictable and smooth energy purchase costs. The capacity obligation of the Buyer is (partially or totally) contractually transferred to the seller (the generator) as an availability or committed generation capacity obligation.

For an hour (an energy balancing period), if the actual energy extracted from the grid by the Buyer (measured with the metering system at its CDPs) is greater than contracted quantity, the Buyer will buy the shortfall (the uncontracted energy) in the BME. Therefore, the Buyer pays if not fully contracted:

- Contracted energy at contract energy prices; plus
- Non-contracted energy at price in the BME.

If instead the metered energy is less than the contracted quantity, the Buyer sells the surplus in the BME at the BME price for this period (the Buyer is over contracted in energy for that period). In that case the Buyer pays all the contracted energy at contract prices, but is compensated by selling the surplus contracted energy in the BME at its price.

In summary, the energy purchase cost of a demand Participant results as follows:

- Energy purchase cost in contracts; minus
- Revenues from sales of surplus energy (when energy contracted is greater than the actual energy extracted from the grid by the Buyer) in the BME; plus
- Purchases in the BME when contracted energy is less than actual energy extracted from the grid

metered at CDPs.

Indicative example: A Supplier with two Financial Supply Contracts with fixed energy quantities, hourly energy results (buying and selling):

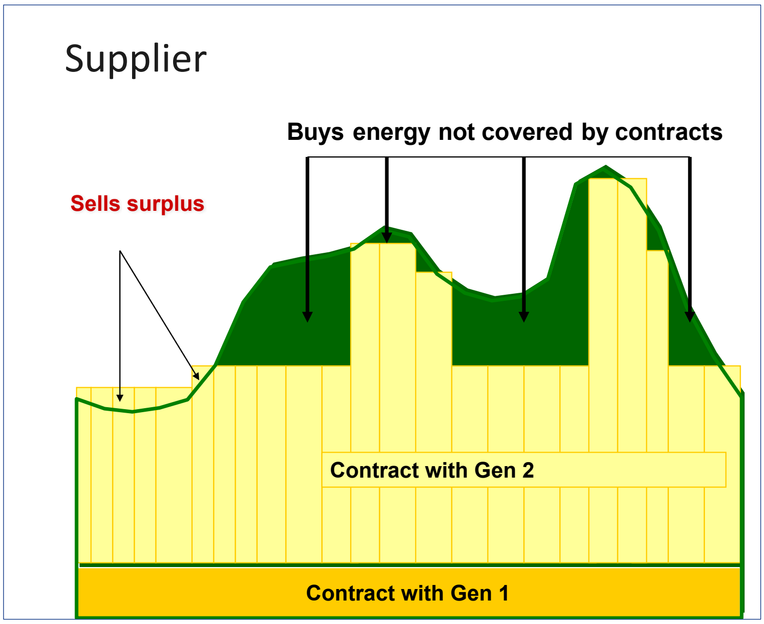


Figure 7 - Financial Contract results on the Buyer's side

A similar result applies for the contracted capacity. The shortfall or surplus compared to the capacity obligations will be cleared through the BMC, at its price for the capacity in the balancing period (one year).

8.7. Capacity Only Supply Contracts

This design is an option to allow a Demand Participant that has contracted energy-only generation (for example with renewable energy) to purchase separately the capacity required to comply with its capacity obligations.

Similar to the description of previous types of contracts, the contract can be designed as a share (a percentage) of the capacity available of a Generator or a percentage of the capacity required by the Demand Participant to cover its capacity obligations. The contract can follow the design of availability commitment including payment by the seller in case the agreed commitment is not met and as a result, the buyer is exposed to the balancing mechanism.

Alternatively, this type of contract could be agreed between two generators to cover possible shortfall in capacity committed in contracts (similar to secondary trading). For example, if a Generator that has committed 100 MW available capacity and needs to carry out an unplanned maintenance, the Generator could contract the capacity from another generator that has a surplus uncontracted capacity to avoid the imbalance in the BMC and the compensation payment for unavailability, if applicable depending on contract conditions.

If a Generator 1 contracts capacity from another Generator 2, for the purpose of capacity balancing and contractual obligations, it is considered as if the contracted capacity of Generator 2 “belongs” to Generator 1.

- The capacity balance calculation for each Generator would be: actual availability of the Generator, plus capacity bough in contracts from another Generator, minus total capacity sold in contracts (including capacity contracts selling to another generator).

8.8. CONTRACT PORTFOLIO AND CONCLUSIONS

In practice, competitive electricity markets are characterized by buyers and sellers managing risks through a portfolio of tools, mainly portfolios of different contracts plus, in more advanced and sophisticated markets, financial instruments, future markets, etc.

The balancing mechanisms are the market instrument that allow diversification of buyers and sellers, contract design and portfolio in a power sector that promotes efficient use of resources through a centralized economic dispatch.

It is reasonable to envisage that initially the market in Pakistan will start with generators or demand participants adopting one or two types of contract design. However, as experience develops and there is a better understanding of risks and benefits of each contract design, the participants will move to a portfolio of a mix of different types of contracts tailored to their needs or specific characteristics.

The examples shown previously for each contract design corresponds to results, imbalances and revenues if the parties use only one contract design. However, a similar assessment can be done for a portfolio of different types of contracts (any possible combination, e.g. a Generation Following Supply Contract and one of more Financial Supply Contracts with Fixed Quantities). The parties will undertake such kind of analysis before selecting a portfolio of contract.

The allocation of imbalance risk varies depending on contract design. For example, for energy:

- If a Supplier or Bulk Power Consumer procures with Load Following Contracts covering all (100 %) of its energy, the demand will have no energy imbalance.
- If all supply contracts are designed as generation following, the only energy imbalances that will exist are for the demand, as percentage / share established in the contract(s) is different to total actual energy required. The transactions in the balancing mechanism for energy would be among demand participants only.

9. COMMERCIAL ALLOCATION OF PRE-EXISTING CONTRACTS

9.1. NEED FOR COMMERCIAL ALLOCATION

By commercial allocation, it is meant that the current generation procured as single buyer will be commercially allocated to all DISCOs and KE, based on a criterion (explained below). As CTBCM is designed as bilateral contracts market in which DISCOs will be allowed to have bilateral contracts with generations in order to meet their capacity obligations. In order to calculate the need for new capacity, each DISCO must know in advance that how much it has already contracted. Through this allocation, each DISCO will be assigned a fixed quantity (subject to revisions in future) from the already contracted capacity so that their future needs can be calculated based on their demand forecasts.

9.2. SITUATION BEFORE THE CTBCM START

Currently in Pakistan, PPAs and EPAs have similarities with the Generation Following Supply Contract as described previously. However, the DISCOs as demand did not sign the purchase agreements, and the sellers (generators) invoices to one party (previously WAPDA acting as Single Buyer, later CPPA of NTDC in representation of DISCOs and to the CPPA-G acting formally as the agent of each and all DISCOs and KE (for the share that it procures through CPPA-G).

Currently, PPAs have, in general terms, the following features for thermal generation or generation with capacity payments:

- Energy costs are pass through. As established in the Grid Code and the NTDC license, the generated energy is decided by the SO based on an economic dispatch within system constrains
- Available Capacity is paid regardless the generator is generating or not, i.e. capacity is take-or-pay cost
- If contracted available capacity is not met, liquidated damages shall apply
- Some PPAs have minimum energy generated conditions, i.e. energy take-or-pay costs

9.3. PREPARATIONS FOR THE CTBCM

In the CTBCM, future procurements will be through bilateral contracts. The future procurement will be done directly by DISCOs through facilitation from the IAA. The existing agreements will be managed by SPT and will be commercially allocated to DISCOs. This will ensure a smooth transition and avoid the hurdles that will be faced if the contracts are legally assigned to DISCOs and KE. However, this option can be considered at later stages of the market to legally bilateralize the market.

For the commercial allocation of the existing PPAs and Energy Purchase Agreements (EPAs) into bilateral contracts there are two aspects that need to be addressed:

- **Legal aspects:** Modify the existing PPAAs with all DISCOs and KE;
- **Allocation aspects:** Capacity and energy of each existing PPA or EPA to be allocated to each DISCO and KE (in their supplier role) in the bilateral contracts, hereinafter referred as "Allocation" of capacity and energy

This section describes the impacts of different allocation factors that can be used to decide how to allocate the contracted Capacity and Energy in the existing PPAs and EPAs to the new bilateral contracts to be established to start the CTBCM.

The objective is to allow in the CTBCM all the contract designs described before in this document. Each Participant will have the freedom to decide the type of contract it will use, provided that for regulated distribution licensees (in their supplier role until licensed as suppliers), contracts will be subject to review and approval by NEPRA as regulator.

However, the existing PPAs and EPAs have legal limitations to be integrated into the CTBCM in a way that these can't be converted into all types of contracts as allowed in the CTBCM. For example, the contracts do not foresee that generators will have to participate in a BME, therefore it is required to select the contract design that better fits these limitations. The <u>Generation Following energy supply contract with available capacity obligation</u> should be the type of contract to be considered provided that it adapts to transform the existing PPAs and EPAs into bilateral contracts that do not participate in the BME and can be integrated with all new market contracts designed as previously described in the report. It is important to mention here that the sellers with the legacy agreements will not be impacted in any manner with the commencement of the CTBCM.

In Generation Following supply contracts, the sellers do not have energy imbalances, but the demand Participants that are the Buyers (Suppliers (DISCOs and others) and BPCs) will have energy imbalances. The bilateral contract would buy a share (percentage) of the generated energy and contracted capacity, independent of actual energy taken from the grid by the Buyer or its actual capacity obligation. Therefore, the energy result of the bilateral contracts allocated would be that trading in the balancing mechanism for energy (BME) will apply only to the Buyers (DISCOs as Suppliers or other Suppliers reselling to demand or BPCs).

All bilateral contracts resulting from Allocation, shall be registered in the Contract Register, a requirement for the MO to carry out its functions of administering the balancing mechanisms by calculating the imbalances between contracted and actual quantities.

9.4. ALLOCATION CRITERIA

In order to implement the Generation Following Supply Contracts for the bilateral market, for each existing PPAs and EPAs it is necessary to define what share (percentage) of each agreement will be allocated to each one of the existing DISCOs (in their role as Last Resort Suppliers) and KE (for the share that it procures through CPPA-G).

The definition of these shares can be done in different ways, so it will require to choose the one that better fits the objectives of the new market. This is a very sensitive decision, because depending on the chosen option, the resulting generation costs for each DISCO may be different. This is mainly because the demand profile of each DISCO is not the same.

Today, the generation costs are charged to the DISCOs and KE through the Energy and Capacity Transfer Charges, which are the same (per unit) for each DISCO and KE, and applied to the energy demanded by each DISCO and KE and proportionally to the peak demand of each. However, and even if these charges are the same for all DISCOs, the fact that each has a different load factor, means that:

- DISCOs with low load factor, pay proportionally more for capacity than for energy, and therefore the resulting total generation costs is higher compared with the total generation costs for DISCOs with higher load factor
- DISCOs with a high load factor, pay proportionally less for capacity than for energy, and therefore the costs are lower.

If a fixed allocation criterion is used for several years, the following example shows consequences in terms of costs for each DISCO. Following graphs shows the evolution of Average Power Purchase Power Prices for all DISCOs for two different time periods, 2019/2020 and 2024/2025, where it is noticeable how this difference increases.

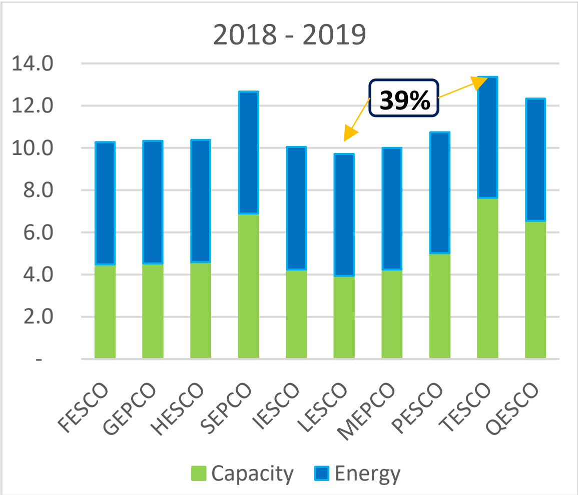


Figure 8 - Average Gen Prices 2017/18

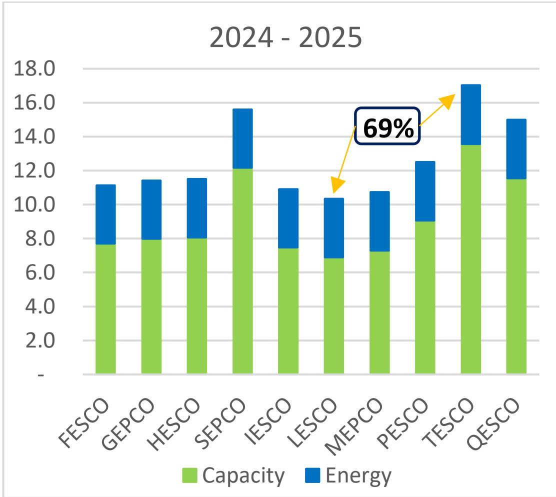


Figure 9 - Average Gen Prices 2024/25

Based on the previous description of the Generation Following design, the allocation of the existing contracts to the DISCOs and KE will be decided during the implementation phase.

The methodology used shall ensure that the sum of the percentages in contracts (for the commercial allocation of a PPA or an EPA) with all DISCOs and KE always adds 100%.

10. Contract Register

The Market Operator will implement, update and maintain a Contract Register. Participants are obliged to register information on all contracts with the Market Operator to be able to calculate and settle imbalances. The Contract Register will include:

- The contracted Quantities, fixed, percentages or formulae to calculate the contract amount
- The metering location
- Contract period
- Procedure for termination etc.

The MO will use the Contract Register:

- To determine energy and capacity balancing quantities, information in the register will include parties, duration, points of sale and purchase, if the contract is energy only or energy and capacity, energy quantities and contracted capacity (payment for available or committed capacity).
- For pre-existing PPAs that establishes energy price as variable cost of generation, the energy price will be registered by MO. For any new PPA, the Seller will provide as information for the register, the components and formula for the variable cost of generation. This information will be communicated to the System Operator to be used in the Security Constrained Economic Dispatch, and to determine energy balancing prices by the Market Operator.

The information for Contract Register will be obtained through Market Participation Agreement (MPA). The template of this agreement will be developed by the MO and will be approved by NEPRA.

11. MARKET DESIGN: ENERGY BALANCING MECHANISM

When parties contract bilaterally using a network shared with others, the market needs an energy Balancing Mechanism because there is always tendency to deviate from the contracted amounts. Practical implementation of the bilateral contract market may face challenges, as the energy generated will not be able to follow exactly the consumption of the demand that are parties in the contract, nor the demand will be able to adjust consumption to follow the generation pattern of the seller in the contract. Moreover, network constraints may limit energy generated or supply. In summary imbalances will exist and therefore it is critical to have proper pricing mechanisms for those imbalances to be fair to the sellers as well as buyers and to avoid creating distortions or additional costs that burdens one or other party.

In the CTBCM, the Market Operator will administer the Balancing Mechanism to clear differences arising from contractual agreements. The centrally administered Balancing Mechanism is designed to achieve the following objectives:

- To enhance competition and transparency, by creating reference competitive energy prices that can be used in the negotiation and design of bilateral contracts;
- To facilitate contracting and allow different contract designs, by clearing difference between actual / forecasted demand (or exports) or available generation (or imports), and energy committed in medium to long term contracts (including import and export contracts);
- To provides price signals on lack of adequate reserves or surplus generation.

The Energy Balancing Mechanism allows a free contract market environment where Participants agree long and medium term buying/selling agreements, harmonized with the realities of maintaining a balanced and reliable system (that imposes system security constraints) and the centralized economic dispatch to optimize use of available generation resources and promote efficiency among generators competing for dispatch. The energy Balancing Mechanism will ensure the following:

- All energy injected to the grid is paid either through PPAs/EPAs/bilateral contracts, or through the Balancing Mechanism;
- All energy taken from the grid is paid either through PPAs/EPAs/bilateral contracts or through the Balancing Mechanism.

11.1. ENERGY IMBALANCES

The purpose of the balancing mechanism for energy is to settle the difference between energy quantities agreed in contracts (bilateral) and the physical results of the generation scheduling and economic dispatch and real time operation by the SO within system security constraints (and including losses), and actual energy extracted from the grid by the demand Participants. Actual wholesale energy quantities are determined through the commercial / settlement metering systems in the CDPs and any adjustments that may be required based in market metering procedures taking into consideration the metering system register, plus for Demand Participants, the uplift to add transmission losses to be covered by the demand (if ultimately chosen).

The following parties are injecting or taking energy from the grid, and therefore possible parties in the BME (balancing mechanism for energy):

Generators (and Supplier/Trader representing generation):

- The energy injected is determined for each hour of the month, resulting from the commercial/settlement metering system and the market metering procedures. The integration of the hourly energy is used to determine daily, monthly, and annual energy injected in the market.
- The committed energy in contracts is determined for each hour of the month totaling the energy sold in contracts by the Generator for that hour, using the information in the Contract Register.
- As described before, each contract must establish a formula or fixed quantities to determine the contract energy schedule on hourly basis. The integration of the hourly total contracted energy schedule determines daily, monthly, and annual energy sold by the generator in the Contract Market.
- The hourly energy imbalance is calculated as energy injected (first bullet above) minus total energy contracted (previous bullet). For a Generator fully contracted with Generation Following design (and the commercial allocation of PPAs and EPAs) imbalances will always be zero as the energy bought in contracts is the energy injected to the grid at CDPs.
- The integration of the hourly energy imbalance is added to calculate daily, monthly, and annual net energy imbalance of the Generator. Imbalances can be positive or negative, so the addition shall be made with the respective positive or negative signs. It is important to mention here that the imbalance for each hour will be values at the corresponding marginal price of that hour before the aggregation at daily, weekly or monthly basis.

Imports: For the purpose of administration of the market, an electricity import will be considered as a Generator “connected” in the international interconnection and represented in the market by the Participant that is the purchasing/import party in the contract. The purchasing party will be registered with the Market Operator and will be treated as a Generator. The contract between the purchasing party and the seller will be outside the market.

- The energy injected is determined for each hour of the month, with the commercial/settlement metering system in the international interconnection. The integration of the hourly energy is used to calculate daily, monthly, and annual energy imported in the market.
- The committed energy in an import contract is determined with the energy schedule coordinated by the SO with the relevant system operators of the other power system(s) as committed exchange or exchange nomination. In this case, the commitment is defined by the hourly energy schedule in the interconnection agreed at least one day in advance by the SO or the system operators involved in the management of the import transmission link (and any modification agreed in advance to the hour during the day).
- The hourly energy imbalance is calculated as actual energy injected (first bullet above) minus energy import committed/nominated and agreed in advance by the SO with the entities responsible of system operation in the other power system(s) (previous bullet). This means, that the imbalance for cross border exchanges reflects the difference between the exchange agreed in the coordination and planning of the system operation, and the actual energy received. The integration of the hourly energy imbalance is added to determine daily, monthly, and annual energy imbalance in the import, which can measure the deviations of the purchaser from imports

Demand Participant: Distribution licensees (last resort suppliers), Competitive Suppliers reselling to demand, and Bulk Power Consumers (BPCs) participating in the market:

- The energy extracted from the grid (the "wholesale consumption" for the market) is determined for each hour of the month at the corresponding CDPs, using the commercial/settlement metering system and the market metering procedures, plus the uplift to add the losses. The integration of the hourly energy is used to calculate daily, monthly, and annual energy extracted and bought in the market.
- The total energy purchased in contracts is determined and totaled for each hour of the month, with the information in the Contract Register. As described before, each contract must establish a formula or fixed quantities to determine the contract energy schedule. For Demand Participants fully covered with Load Following Contracts, the imbalance would be negative and correspond to the transmission losses (if not covered under contract), for that Participant to pay its share of the transmission losses cost. The integration of the hourly total contracted energy schedule will be used to calculate daily, monthly, and annual energy purchased by the Demand Participant in the Contract Market.
- The hourly energy imbalance is calculated as wholesale energy extracted (first bullet above) minus energy contracted (previous bullet). The integration of the hourly energy imbalance is added to calculate daily, monthly, and annual energy imbalance of the Demand Participant.

Exports: For the purpose of administration of the market, an electricity export will be considered as a Demand "connected" in the international interconnection, and represented in the market by the Participant that is the seller/export party in the contract.

- The energy extracted is determined for each hour of the month, with the commercial/settlement metering system in the international interconnection plus an uplift to include transmission losses (if ultimately decided). The integration of the hourly energy is used to calculate daily, monthly, and annual energy exported.
- The committed energy in export contracts is determined with the energy schedule coordinated by the SO with relevant system operators of the other power system((s) as the committed exchange or exchange nomination. Similar to imports, the commitment is defined by the energy export schedule in the interconnection agreed at least one day in advance.
- The hourly energy imbalance is calculated as energy extracted / delivered in the international interconnection (first bullet above) minus energy export committed/nominated and agreed in advance by the SO with the entities responsible of system operation in the other power system(s) (previous bullet). This means, that the imbalance for exports reflects the difference between the exchange agreed in the coordination and planning of the system operation, and the actual energy sent. The integration of the hourly energy imbalance is added to determine daily, monthly, and annual energy imbalance in the export, which can measure the deviations in the export arrangements.

Traders and Competitive Suppliers (suppliers selling only to BPCs): As traders and Competitive Suppliers will be buying and selling at the wholesale level, therefore, depending on the types of contracts, will be subject to balancing mechanism. As these entities will not have any physical generation or consumption, there balancing will be calculated in the following manner:

- The total energy bought through contracts will be calculated on hourly basis using the information in the contracts register. If the calculation of the contracts requires physical measurements, the information will be obtained through metering system at the corresponding CDPs.
- The total energy sold through contracts will be calculated on hourly basis using the information in the contracts register. If the calculation of the contracts requires physical measurements, the information will be obtained through metering system at the corresponding CDPs.
- The imbalance will be calculated as the total energy bought through contracts (first bullet) minus total energy sold through contracts (second bullet)

11.2. Energy Balancing Pricing-Marginal Pricing

As the Energy Balancing quantity will be calculated for each hour (each energy balancing period), the pricing of the balancing mechanism for energy will also be hourly. The energy balancing price will be based on the marginal cost principle as described below.

Energy balancing prices will be determined based on **generation variable cost** used by the SO in the economic dispatch of the power system. The generation variable cost will be as declared by the generator in accordance to the Grid Code and, for pre-existing PPAs, the variable costs in accordance to the energy contract price (PPA's Schedule) and NEPRA generation tariff determination. For the purpose of the energy balancing price calculation, the following considerations will apply:

- Any must dispatch generation (for example, Wind, Solar, Run-of-river Hydro, Take or Pay commitments) is considered with variable cost zero.
- Any generation "forced" to generate by system security constraints (any generation that would not have been included in the economic dispatch should there be no system constraints) is not considered for setting the price and appropriate provisions will be established for such cases.
- For hydro generation with reservoirs, it is recommended to consider as variable generation cost the opportunity cost of the water storage, using an optimization "water value" model.

The SO will carry out the generation scheduling, and dispatch using adequate software model and inform the results the day before on its website and electronically to the MO. During daily operation, the SO may modify the dispatched generation schedule (an economic re-dispatch) to adjust to actual conditions being different to expected in the day ahead operational plan, the new dispatch schedule information and justification will be made public at the end of the day in the next daily operation report.

In summary, at the end of each day and for each hour, the results of the SO economic dispatch will result in a list of generations dispatched with the corresponding variable generation cost determined as described above.

The BME price will be on hourly basis calculated through a detailed methodology which will be developed by MO and will be approved by NEPRA. This pricing signal will deliver better economic signals, and will require for the SO to have in place a robust and well tested economic dispatch software that incorporates system security constraints, and preferably also water value for hydro.

11.3. Settlement of the Energy Balancing Mechanisms

For each hour of each day, the MO will calculate the following for the balancing mechanism for energy:

- For each Participant, the energy imbalance quantity resulting from real time operation (metered data plus adjustments as applicable including the uplift for transmission losses and total contracted energy schedule, as described in the section on contract designs (*Section 8*) and the section on transmission losses (*Section 13*).
- The hourly energy imbalance price with the information provided by the SO on variable generation costs and the results of economic dispatch and real time operation for that hour.

For each Participant, the monthly settlement for the BME will be determined totalling the value of the hourly energy imbalances, calculated hourly as:

- The imbalance quantity (negative if buying, positive is selling);
- Multiplied by the energy imbalance price for that hour.

If the monthly net result (the integration of the hourly imbalance cost) is positive, the Participant results a Seller in the Balancing mechanism for energy for the monthly settlement.

If instead the monthly result (the integration of the hourly imbalance cost) is negative, the Participant results a Buyer in the Balancing mechanism for energy for the monthly settlement.

The MO will post these settlements on its website on daily basis so that objections/errors/omissions are rectified at earlier stage. In the monthly settlement (which will include all reconciliations from the daily calculations), the MO will calculate and inform:

- For each Participant, the monthly energy quantity in the balancing mechanism for energy, energy balancing prices, and the amount the Participant must pay (if monthly result is negative) or will be paid (if monthly result is positive)
- The total amount to be paid by Participants for the Balancing mechanism for energy (purchase of negative monthly energy imbalance).
- The total amount that will be paid to Participants for sales in the Balancing mechanism for energy (sale of positive monthly energy imbalance).

11.4. Settlement Document

Each month, the MO will prepare the Settlement Document, which will contain all the information required by the Participants to proceed with the bilateral invoicing. For all types of contracts and based on the information collected from the commercial settlement metering systems, the MO will prepare for each settlement period of the month, also the information regarding the centralized administered markets, such as the Balancing Mechanisms, transmission losses calculation and allocation, etc.

The fact that this document will be prepared based on a commercial metering system that complies with the Grid Code specifications (included accuracy and information security) and is subject to the monitoring process as indicated in the same Code, makes that the Settlement Document will be the reference information for the settlement between the Participants.

Any discrepancy between information produced by the Participants and the Settlement Document, will have to be solve with the intervention of NTDC, responsible for the data accuracy and the MO, responsible for the calculations required to produce this paper.

The Settlement Document will be posted on the online portals of the MO and it is recommended to make it accessible without any restriction, as a way to cement the transparency in the market.

12. Market Design: Capacity Obligations and Capacity Balancing Mechanism

12.1. Capacity Obligations and Firm Capacity

In addition to energy, the electricity market will include the trading of capacity, designed under the following principles:

- Long term reliability of supply should be achieved at efficient price;
- A regulated mechanism: to quantify the capacity interchanges and the prices to be applied to these interchanges;
- The mechanism should provide incentives for timely new generation investments, and as necessary adequate generation capacity, and adequate reserves (generation technical and fuel availability) to ensure supply during peak demand and unexpected extraordinary circumstances;
- Ensure adequate firm capacity for critical situations (e.g. dry periods/low hydrology, high demand during summer);
- Provide stability and predictability to attract sufficient interested investors and competition.

Each and all Demand Participants will have Capacity Obligations (e.g. Participants that are Competitive Suppliers or DISCOs (as Last Resort Suppliers)) have the obligation to contribute with a share of the required firm capacity to ensure reliable supply (with adequate reserves as defined in the Grid Code). The Capacity Obligation would be determined as the Demand Participant share (or its participation) in the generation required to supply the system peak plus reserves.

A Demand Participant can cover its Capacity Obligation through firm capacity it owns or contracts, and purchasing any shortage in the Balancing Mechanism for Capacity administered by the Market Operator.

Generators can sell Firm Capacity through contracts and the un-contracted available capacity in the Balancing Mechanism for Capacity.

- Firm Capacity for thermal generation will be calculated based on historical availability; and for new power plants without a history of actual availability, based on typical availability for similar technologies and dependable capacity through tests monitored by the System Operator.
- For hydro, firm capacity will be determined simulating dispatch under dry conditions and assessing maximum capacity it can deliver constantly during the peak period, or as the average capacity during the peak period. The determination of firm energy or firm capacity of a hydro power plants is usually carried out with simulation and optimization models, which are also for medium term planning
- For variable renewable energy technologies such as solar, wind and run-of-river hydro, a proper methodology will be established to calculate their firm capacity based on their contribution to the system security.

12.2. BALANCING MECHANISM FOR CAPACITY

The Balancing Mechanism for Capacity will complement the capacity obligations of each market participant, providing a mean to settle the eventual differences that may exist between the capacity demanded and actually provided. The purpose of the balancing mechanism for capacity is to conciliate the difference between the capacity obligations of Demand Participants and the available capacity of Generators during critical hours, with the capacity contracted (bought or sold in contracts).

Demand Participant with capacity obligations and generation selling capacity in contracts will participate in the Balancing Mechanism for Capacity (BMC). Additionally, power plants with uncontracted available capacity that can be committed and are dispatchable will offer their capacity to the BMC.

The Balancing Mechanism for Capacity will be executed once a year, during the two first months after the end of each fiscal year.

Following paragraphs outline the procedure for the settlement of this Balancing Mechanism.

12.2.1. STEP 1: IDENTIFICATION OF CRITICAL HOURS

For balancing purposes, the Capacity provided by generators and taken by the demand will be calculated for the “Critical Hours. The critical hours are those hours of the previous year, in which the power system is at maximum stress. In principle, these hours are those in which the amount of reserves of the system are minimal.

The System Operator will be responsible to develop a methodology, which should be approved by NEPRA, for determining these hours, considering:

- The characteristics of the demand;
- The production of wind and solar generation (which, for their characteristics, will not be providing reserve);
- The specific characteristics of the constraints associated with hydraulic generation;
- The generation maintenance plans; and
- The regulation requirements of the whole system.

During the first phases of the implementation of the Balancing Mechanism for Capacity (BMC) and until such methodology will be completed, the critical hours will be those in which the total demand were higher. In principle, in order to avoid volatility in the determination of these hours (and the associated Capacity determinations) it is considered that these hours will be among 50 and 100.

Due to the load curves characteristic of Pakistan, the most loaded hours will occur typically between June and September. Once these hours be identified, the System Operator will communicate them to all Market Participants.

As an example, in the following figure, the “critical hours” (higher demand) corresponding to the year 2018 are represented in orange.

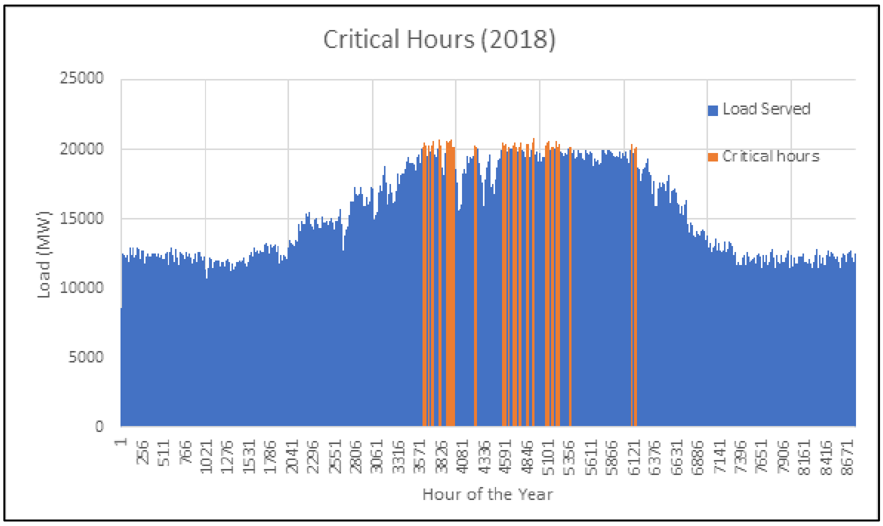


Figure 10 – Most loaded hours in 2018

12.2.2. Step 2: Actual Available Capacity for Generators

The amount of power capacity that will be credited to each generator, for the capacity balancing mechanism (expressed in MW-year), will correspond to the capacity delivered by such generator to the system during the "critical hours". This capacity will be calculated yearly by the System Operator, immediately after the end of the year, as the average production availability of each generator or power plant during the identified hours.

The production availability, calculated by the System Operator for each hour will be different depending on the type of generator involved:

- For variable renewable energy plants (without storage): The production availability will be equal to the generation of such plant at each critical hour. Special consideration will be given to energy curtailed due to transmission constraints;
- For non-energy limited power plants (capable to provide firm capacity): The production availability will be equal to the availability communicated by such generator or plant to the System Operator, following the prescriptions established in the Grid Code;
- For energy limited power plants (hydro power plants): The production availability will depend on the type of regulation capability of the plant.
    - In case its regulation capability is monthly or shorter: They will be treated as variable energy resources, taking due consideration of the plants having reservoirs and limited by operational constraints
    - In case its regulation capability is annual or longer: They will be treated as non-energy limited power plants.
- For import power (in which there are no compromises for firm capacity): The production availability will be decided as per nature of the contract. In other cases, NEPRA will decide the way to determine the value, based on the recommendations issued by the System Operator.

The determination of actual availability of generation will be a responsibility of the System Operator (SO) in accordance with the Grid Code and its implementation operational procedures, based on:

- Maintenance outage plans and actual outages;

- Availability declarations of each power plant / generation unit, before each day as part of the operational planning and day ahead generation scheduling, and adjustments to availability (changes) declared / informed by the generator during daily operation;
- Tests through the SO instructing the generation to increase its generation to the declared available capacity or, if the unit or power plant is not generating, instructing the startup and to deliver the declared available capacity;
- If the unit or power plant is not dispatched for a significant period, the SO may audit operational book at the power plant to confirm no maintenance was done during that period except for maintenance informed by the generator in advance and coordinated and authorized by the SO.

The SO will publish in its website operation reports (daily, weekly, monthly and annual) the declared available capacity and actual available capacity for each Generator, and any availability different than declared which was identified through the tests and audits described above. Additionally, the SO will provide this information electronically to the MO.

12.2.3. Step 3: Capacity Requirements by the Demand

The annual capacity requirements by the demand, that is the amount of power that each market participant serving load is obliged to obtain for each year in which it has carried out operations in the CTBCM, will be calculated by the System Operator according to the following formula:

$$APR = PD * (1 + P_L) * (1 + RM)$$

Where:

APR is the Annual Power Requirement of the particular demand (BPC or group of loads);

PD is the average Peak Demand by a particular demand, referred to the transmission system, during the “critical hours” registered by the metering system;

P_L are the average losses in the transmission system; and

RM is the Minimum Planning Reserve.

The Minimum Planning Reserve for the Pakistani system will be calculated by the Planner and submitted to NEPRA for approval. The Minimum Planning Reserve shall be expressed as a percentage of the whole system demand and it will be the minimum reserve required to:

- Assure secure operation of the system at all times (operational reserve); plus
- The minimum amount of reserve required to comply with the limits established in the Grid Code.

NTDC, in the Indicative Generation Capacity Expansion Plan will propose the values to be used for the second item.

Calculation Example

Assume that:

- The average load of a BPC, registered by the metering system, during the 100 critical hours has been 14.6 MW.
- The losses in the transmission system, approved by NEPRA, were 3.0%

- The System Operator has estimated the minimum operational reserve (for properly control frequency) in 4.0 % of the load.
- NTDC has estimated that the minimum reserve, necessary to comply with the LOLP of 1% established in the Grid Code is 12.0 %
- NEPRA, upon request of the SO, has approved a Minimum Planning Reserve for such year of 16.0%

Therefore, the Annual Power Requirements of such BPC, which will be used for balancing purposes, is:

$$APR = PD * (1 + P_L) * (1 + RM) = 14.6 * 1.03 * 1.16 = \mathbf{17.44\ MW}$$

12.2.4. Step 4: Capacity Balances of each Market Participant

The Market Operator will calculate the Capacity Balance of each Market Participant using:

- The information provided by the System Operator in relation with the Credited Capacity of generators and the Annual Power Requirements of the demand, and
- The information included in the registered contracts.

The Capacity Balance of each Market Participant will be determined as the difference between the credited capacity and the power requirements taking into account the capacity purchased or sold through bilateral contracts with other market participants. It will be calculated as:

$$CB_i = AAC_i - APR_i + CP_i - CS_i$$

Where:

CB_i is the Capacity Balance of Market Participant *i*

AAC_i is the Actual Available Capacity of Market Participant *i*

APR_i is the Annual Power Requirement of Market Participant *i*

CP_i is the capacity purchased by Market Participant *i* from other market participants through bilateral contracts, which have been registered with the Market Operator.

CS_i is the capacity sold by Market Participant *i* to other market participants through bilateral contracts, which have been registered with the Market Operator.

For appropriate delimitation of capacity responsibilities, all the contracts registered with the Market Operator, regardless of their type, should clearly indicate the capacity that it is purchased and sold and the entity which will be responsible for the capacity balance.

Calculation Example

Assume that:

- Generator G1 has an installed capacity of 100 MW.
- G1 has signed two contracts, with Supplier S1 and Supplier S2. The contract with Supplier S1 is a generation following contract, with a guaranteed capacity of 60 MW. The contract with Supplier S2 is a supply contract, with maximum capacity of 36 MW. In both contracts it has been stated that the suppliers receives firm capacity (the obligation to provide such capacity relies on the generator G1).

- S1 has signed a contract with BPC1. The maximum capacity stated in the contract is 60 MW. S2 has signed a contract with BPC2, with maximum capacity of 35 MW. In both cases it was stated that the balancing responsibility of BPC1 and BPC2 has been transferred to their suppliers.
- During the "critical hours":
    - The average availability of G1 (credited capacity) was 87 MW.
    - The Annual Power Requirement of BPC1 was 58 MW.
    - The APR of BPC2 was 37 MW.

Therefore, the capacity balances of each market participant are:

- $CB_{G1} = 87\ MW - 0\ MW + 0\ MW - 96\ MW\ \ =\ \ \boldsymbol{-9\ MW}$
- $CB_{S1} = 0\ MW - 58\ MW + 60\ MW - 0\ MW\ \ =\ \ \boldsymbol{+2\ MW}$
- $CB_{S2} = 0\ MW - 37\ MW + 36\ MW - 0\ MW\ \ =\ \ \boldsymbol{-1\ MW}$

Which means, for balancing purposes:

- G1 has to purchase 9 MW to comply with its obligations
- S1 will offer 2 MW to the balancing market
- S2 has to purchase 1 MW to comply with its obligations

- BPC2 has exceeded the maximum demand agreed with its supplier in 2 MW. However, as if the contract transfers its obligations to the supplier, it has not to purchase this amount in the BMC. This excess has to be settled bilaterally, according with the clauses agreed in the BPC2-S2 contract.

12.2.5. Step 5: Determination of the Reference Technology

The price of the capacity will be determined by the estimating the cost of the most economic generation unit capable to provide 1 MW of capacity (and associated energy), only for the determined "critical hours".

This capacity cost (expressed in PKR/MW.year), corresponding to the most appropriate technology (least cost technology), will be calculated by the Planner yearly, utilizing the information provided by NTDC in the latest approved Integrated Generation Capacity Expansion Plan. For such purpose it will consider different generation technologies, determining 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.

- Estimated project investment cost.
    - The costs of the project may include, among other inputs:
        - Equipment costs;
        - Site acquisition costs (land);
        - Engineering, procurement, project management and construction costs;
        - Legal costs;
        - Interconnection costs of the transmission network;
        - Construction costs and interconnection of fuel pipelines, if applicable; and

        - Mobilization and contingent costs.
    - Estimated financial costs of the project
    - The assumed economic operating life of the Reference Generation Technology, considering the salvage value after that operational life.
    - An appropriate discount rate, which shall be prescribed by NEPRA.
- Estimated Revenues: They will be calculated by comparing the system marginal prices at the determined "critical hours" and the variable cost of the technologies evaluated. It is assumed that, if the system marginal prices had been higher than the variable costs of the evaluated technology the generator have been dispatched and it will obtain revenues equal to the difference between these two values.

The levelized fixed cost of the technologies evaluated will 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 this technology would have obtained in the energy market.

The reference technology will be that of lower levelized fixed costs.

12.2.6. Step 6: Determination of the Capacity price

The MO will determine the price for the capacity balancing mechanism making use of two curves: A supply curve and a demand curve (see Figure 2).

- The supply curve: The amount of capacity "offered" will be sum of the capacity balances of all market participants with a positive balance value (capacity surplus). This capacity is considered offered in the balancing mechanism as a price taker.
- The demand curve: The demand curve will have two sections. The mandatory part and the efficient part.
    - The "mandatory" section will start at point A, which corresponds to a capacity of zero and a price equal to two times the levelized fixed costs of the reference technology, and extends horizontally to point B, which corresponds to the sum of the capacity balances of all market participants with a negative balance value (capacity deficit).
    - The "efficient" section will start at point B and it will extend to point C. This point will be determined by the intersection of the levelized fixed cost of the reference technology and the "efficient" demand level.

      The "efficient" demand level is the amount of power that the system should have installed, in the long range, to achieve the optimum level of reserves. The optimum level of reserves for the Pakistani system will be calculated in the IGCEP and it should be approved by NEPRA. This value will be calculated as:

$$EDL = \sum CB_{i-ve} * \frac{1 + RE}{1 + RM}$$

Where:

EDL is the efficient demand level (Point C)

Σ CBi-ve is the total amount of capacity required by the market participants with negative values of balance (capacity deficits)

RE is the efficient level of reserve

RM is the minimum level of reserve, determined in Step 1

- The "efficient" section of the demand curve will extend, with the same slope, up to point D, which corresponds to 80% of the levelized fixed costs of the reference technology. The capacity prices will be capped at such level.

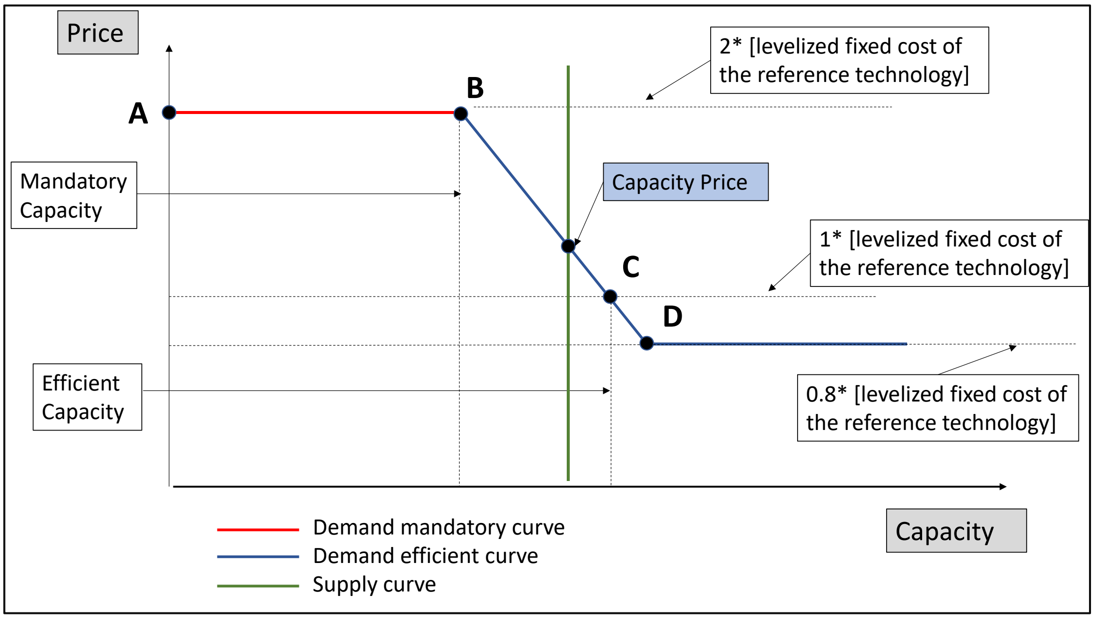


Figure 11 – Demand and Supply Curves for the Capacity Balancing Mechanism

The capacity price, which will be used in the Capacity Balancing Mechanism will be the intersection of the demand and supply curves.

Calculation Example

Assume there are only 6 market participants. The capacity balance for each of them are:

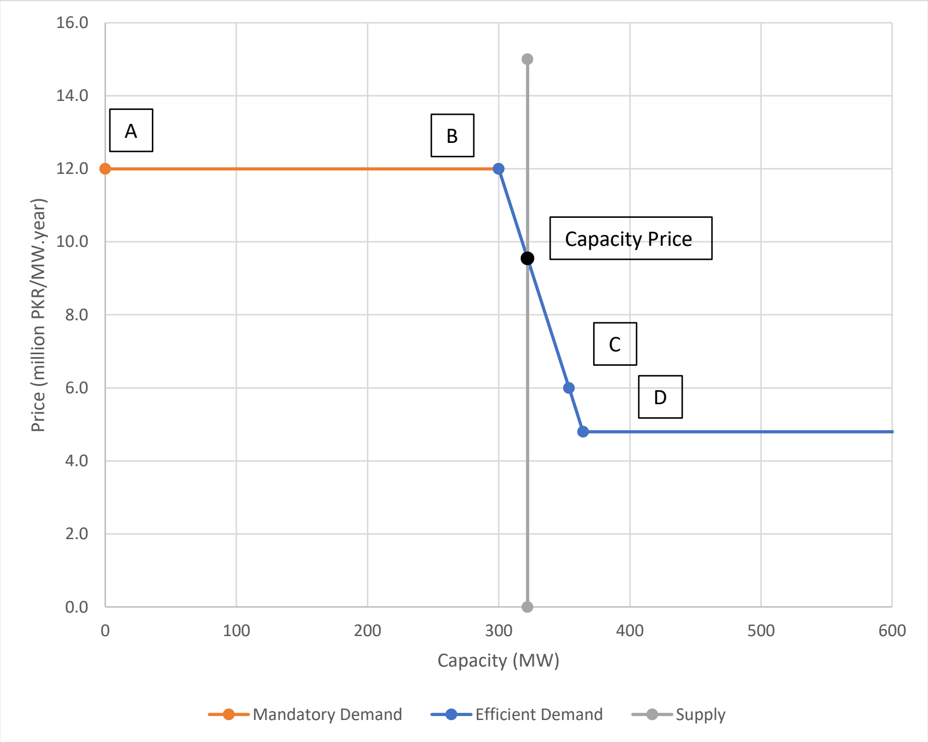
- Generator G1: + 60 MW
- Generator G2: -150 MW
- Supplier S1: - 105 MW
- Supplier S2: + 32 MW
- DISCO: +230 MW
- BPC 1: - 45 MW

The reference technology is a gas turbine, with a levelized fixed cost of 6 million PKR/MW.year-

The Minimum Reserve Margin, approved by NEPRA, was 12% and the efficient reserve margin is 32%.

With this data:

- Point A: [12 million PKR/MW.year; 0 MW]
- Point B: [12 million PKR/MW.year; 300 MW] (150 MW+105MW+ 45 MW)
- Point C: [6 million PKR/MW.year; 353.6 MW] (300 MW * 1.32/1.12)
- Point D: [4.8 million PKR/MW; 364.2 MW]
- Supply curve: 322 MW (60 MW + 32 MW + 230 MW)



The capacity price, therefore, for the Balancing Mechanism for Capacity is: **9.53 million PKR/MW.year**

At least 21 days before the execution of the Capacity Balancing Mechanism, the Market Operator will notify to each Market Participant:

- The total amount of Annual Power Credited;
- The Annual Power Requirement;
- The Capacity purchased and sold by such participant, according with the contracts registered;
- Its Capacity Balance;
- The Capacity Price (PKR/MW.year)
- The net position of the market participant

12.2.7. Step 7: Execution of the Balancing Mechanism (Capacity)

Each Market Participant shall be responsible to provide to the Market Operator appropriate guarantees to cover its expected position in the Balancing Mechanism (Capacity).

On the prescribed date, the Market Operator will settle the balancing position of each participant in the following way:

- If the total amount of capacity offered is equal or higher than the total amount of capacity demanded (total capacity required by Market Participants with negative balance values) then:
  - Each Market Participant with negative balance capacity will pay its balance multiplied by the capacity price.
  - The total amount collected will be distributed among all market participant with positive balance a pro-rata basis.
- If the total amount of capacity offered is lower than the total amount of capacity demanded (total capacity required by Market Participants with negative balance values) then:
  - The total offered capacity will be shared among the market participants with negative capacity balance in pro-rata basis
  - The amount collected will be distributed among all market participant with positive balance a pro-rata basis
  - The market participants which have not been able to obtain the capacity required will be considered as non-compliant with its capacity obligations in the CTBCM. This situation will be communicated to NEPRA which can impose penalties to such market participants.

Continuation of Previous Example

- Generator G2, Supplier S1 and BPC 1 have negative capacity balance, and therefore, they have to purchase this capacity in the Balancing Mechanism for Capacity. In total, they must acquire 300 MW.
- The total capacity available (sum of all market participants with positive balances) is 322 MW 60+32+230 MW). Therefore, there is enough capacity supply for all the purchasers.
- The settlement for each market participant with negative balance is (they have to pay these amounts):
  - Generator G2: 150 MW * 9.53 million PKR/MW.year **= 1529.5 million PKR**
  - Supplier S1: 130 MW * 9.53 million PKR/MW.year **= 1238.9 million PKR**
  - BPC 1: 45 MW * 9.53 million PKR/MW.year = **428.9 million PKR**
  - Total: **3197.3 million PKR**
- The settlement for each market participant with positive balance is (they will be credited these amounts):
- Generator G1: 3197.3 million PKR * 60 MW/322 MW = **595.8 million PKR**
- Supplier S2: 3197.3 million PKR * 32 MW/322 MW = **317.7 million PKR**
- DISCO: 3197.3 million PKR * 230 MW/322 MW = **2283.8 million PKR**
- Total: **3197.3 million PKR**

13. TRANSMISSION LOSSES

13.1. BACKGROUND

The energy metered or delivered at the common delivery points (CDPs) of the demand does not include the energy that was lost as energy flowed through the transmission network (the transmission losses). Transmission losses are part of the cost of supplying the demand and must be considered for the settlement of the bilateral transactions.

There are several approaches used internationally:

- Transmission losses are recovered in the energy market itself. For example:
  - In an electricity market with energy nodal pricing the transmission losses are incorporated into the market energy price as marginal costs of losses. Therefore, the price or cost of losses is part of the energy price and who and how much each participant pays is a result of energy extracted (demand) and/or inject (generation). However, the difference between nodal prices due to losses is greater than the cost of transmission losses. The transmission company receives a variable revenue to cover part of its total revenue requirement.
- Transmission losses are recovered through transmission charges (variable transmission charge), and the type of participants that pay transmission charges pay for the losses
- The transmission company buys the losses, and the estimated or expected cost of losses is included in the revenue requirement to calculate transmission charges.

In Pakistan, the current approach on payment methods for the cost of transmission losses is established in NEPRA's transmission tariff guidelines; tariff determinations and Commercial Code. Transmission Use of System Charges (UoSC) are paid exclusively by the demand (distribution licensees and any bulk power consumer that does not buy from its distribution company). There are two types of UoSC: fixed UoSC (capacity based) to recover the approved NTDC revenue requirement (mainly, fixed costs); and a variable UoSC to recover the cost of transmission losses in case of BPCs not receiving its supply from the DISCO.

In the current model, the formula for the variable UoSC is not defined for DISCOs and, instead, the total cost of transmission losses is incorporated into the energy transfer price paid by each DISCO and KE. As there is a single energy transfer price, in the current approach, each and all DISCOs and KE are assigned the same energy transmission losses (per unit of energy consumed), quantified as NTDC average monthly transmission losses[22] in accordance to the formula for the energy transfer price of the distribution companies.

The NTDC tariff determination also establishes a formula to recover cost of losses from those consumers who are not purchasing from the DISCOs. However, these eventual payments to NTDC are not deducted from the total amount that should be paid by DISCOs.

Regarding how the cost of transmission losses are paid, the current transfer mechanism will need to be revisited to take into consideration the new market structure and introduction of the CTBCM, in particular the separation of activities and the possibility that some customers have the possibility to buy electricity from generators or Competitive Suppliers. This may require modifications to tariff regulations and

[22] The cap defined by NEPRA in NTDC the transmission tariff determination is considered at a later stage, with a compensation to the DISCOs if the cap is exceeded.

determinations by NEPRA. It is important to mention here that the selected approach to transmission losses will affect the administration of the balancing mechanism for energy and the calculation of cost and payment of transmission losses.

The approach proposed here is to uplift the energy metered on the premises of demand participants which are consuming energy to include a percentage corresponding to the transmission losses. Total energy transmission losses (on the period pre-defined by NEPRA) will be compared with the prescribed cap and, in case of exceeding it, the difference will be charged to NTDC at the yearly average marginal price and this amount will be returned to the participants consuming energy pro-rata of their yearly (or monthly) consumption.

The current regulatory approach for NTDC transmission losses allows to recover the cost of transmission losses (energy) up to a cap (a fixed percentage) that applies to an annual target. The recovery of the allowed transmission losses would correspond, in principle, to the energy (variable) use of system charge (energy UoSC). However, as described above, currently this charge only applies to customers which procure their energy from generators other than those which sell their energy to the DISCOs or KE, which practically don't exist. For these DISCOs, (which, in practical terms, cover almost 100% of energy delivered) the cost of these losses is included, implicitly, in the calculation of energy bought by each DISCO and KE. Once the CTBCM starts, the transmission losses need to be assigned explicitly to each Demand Participant, to include as part of the energy extracted (or required) at the CDP for the purpose of its wholesale supply.

On the other hand, according to the NEPRA's guidelines and transmission tariff determinations, the transmission losses are not specifically assigned to each Demand Participant and the cap imposed to NTDC on such losses is an annual target. Therefore, this approach will need to be revisited to make it aligned with the market design.

The variable energy use of system charge for transmission (UoSC) would cease to be applied and only the fixed UoSC would remain in the transmission tariff regulation

Note: In the examples in the Section Contract Design (*Section 8*), the energy of the Buyer should be interpreted as adjusted to include the uplift for transmission losses.

13.2. Proposed Approach

The proposed approach follows the current practice in Pakistan, and it has been worked out based on five premises:

- The transmission losses are paid by the demand. That is, no charges will be applied to generation, regardless of their location (i.e. connected to transmission or distribution levels)
- Transmission losses will be paid following a "postage stamp" methodology. That is, there will not be differences based on the geographical location of the demand (no nodal prices).
- The "zero balance" principle shall be preserved in the BME. That is, the amounts paid by the market participants with negative balance should be exactly equal to the amounts received by the market participants with positive balance, at each energy balancing period (i.e. one hour).
- There would be a cap on the losses that NTDC is allowed to transfer to the demand, which will be applied, initially, on yearly basis. Above such level, the "excess losses" shall be paid by NTDC. As the market evolves and if NEPRA considers it appropriate, this cap can be transformed in a monthly value (different values at each month) without a significant change in this methodology.

- The procedures for implementation shall be as simple as possible.

Based on such principles, following methodology is proposed:

13.2.1. Determination of hourly Transmission losses

Transmission losses will be calculated on hourly basis. The MO will calculate the hourly transmission losses as the difference between total energy injected at the transmission network minus the total energy extracted from the transmission network. This will be done using the settlement metering system and following the metering procedures, considering only those CDP points which involves the transmission network.

$$TransLoss_h[MWh] = \sum_{\forall\, i\, \in CDP_{+}} E_{CDP\, i,h} + \sum_{\forall\, i\, \in CDP_{-}} E_{CDP\, i,h}$$

Where:

- *$TransLoss_h$* are the transmission losses in the hour h, expressed in MWh
- *$E_{CDP\ i,h}$* is the energy injected (positive) or extracted (negative), at the CDPi in the hour h.
- *∀ i ∈ CDP+* means all those CDPs, at the commercial boundary with transmission network, which have a positive balance. That is, such CDP has injected energy to the transmission network during the hour h.
- ∀ i ∈ CDP- means all those CDPs, at the commercial boundary with transmission network, which have a negative balance. That is, such CDP has extracted energy from the transmission network during the hour h.

13.2.2. Uplift on the Energy Demanded by Market Participants

For balancing purposes, all Market Participants which represent demand (DISCOs[23], KE, BPCs, Competitive Suppliers, etc.), regardless of their location in the network (i.e. transmission or distribution) will increase the values of demand assigned to it, at every hour, proportionally to their demanded values.

Since there is generation connected at distribution level, not all the demand is extracted from the transmission network. It is needed, therefore, to determine the total demand of the Market Participants which shall be liable for paying the transmission losses.

This total demand (from the market point of view) shall be obtained, simply, by adding the energy extracted from the transmission network and the total generation connected at distribution level.

$$TotDem_h[MWh] = \left| \sum_{\forall\, i\, \in CDP\, _{-Transm}} ECDPi,h + \sum_{\forall\, i\, \in CDP\, _{+Transm}} ECDPi,h \right| + \sum_{\forall\, i\, \in CDP\, _{+Distrib,}} E_{CDP\, i,h}$$

Where:

- *$TotDem_h$* is the total energy demanded by all Market Participants, which shall be liable to cover the transmission losses.

[23] DISCOs and KE as Last Resort Suppliers

- $E_{CDP\ i,h}$ is the energy injected (positive) or extracted (negative), at the CDPi in the hour h.
- $\forall i \in CDP\text{-}_{Transm}$ means all those CDPs of Demand, <u>at the commercial boundary with transmission network,</u> which have a negative balance. That is, in such CDP energy has been extracted from the transmission network, during the hour h.
- $\forall i \in CDP+_{Transm}$ means all those CDPs of Demand, <u>at the commercial boundary with transmission network,</u> which have a positive balance. That is, in such CDP energy has been injected to the transmission network, during the hour h
- $\forall i \in CDP+_{Distrib}$ means all those CDPs, <u>embedded in to the distribution network,</u> which have a positive balance, during hour *h*.
- $|.|$ means absolute value[24]

The uplift coefficient, to be applied to every market participant representing demand shall be calculated as:

$$Uplift_{TransLoss,h}(\%) = \frac{TransLoss_h\,[MWh]}{TotDem_h[MWh]} * 100$$

13.2.3. Assignment of Demand to Each Market Participant

For balancing purposes, the both the energy injected or extracted to/from the system shall be assigned to a specific market participant. In the cases that the CDP is the interface between a single Market Participant and the transmission network, this assignment is straightforward. However, if several CDPs are "nested" (which is the usual case in which a BPC or a generator are embedded in the distribution network) an initial adjustment shall be done.

13.2.3.1. Referring the metered values to the transmission network

If there are any CDP of a BPC or other eligible customer) located at distribution level (in 132 kV or 11 kV), it is necessary to perform appropriate balances and assignments. This is necessary to avoid double counting and/or to properly assign the losses produced in the distribution network[25].

It is necessary, therefore, to "refer" the metered values to the transmission network and, later on, perform the proper assignment of the metered energy. This "referral" shall be done only in the case CDPs with negative balance in the corresponding hour (demand), since no losses will be assigned to generators[26]:

In the case of BPCs (or other eligible consumers) connected at distribution level, the metered energy shall be increased to take into account the losses in the distribution network[27]. As the losses in the distribution network are not metered every hour, it is recommended to use a standard value, determined by NEPRA. In principle, it is recommended that this standard value be the equal to the technical losses, determined by NEPRA at the latest tariff determination, for the corresponding DISCO. These standard losses could be different, depending on the voltage level at which the BPC (or other eligible consumer) be located. Therefore:

$$E\_BPC_{assigned,h} = E\_BPC_{metered,h} * (1 + DistLoss_h)$$

[24] The values of the demand, for balancing purposes, are negative.
[25] The CDPs at which the DISCOs are metered are, usually, located at the interfaces with the transmission network. Therefore, if there are generators or BPCs "embedded" in such distribution network, it is necessary to perform certain calculations to properly assign the energy extracted to each market participant.
[26] As it is the normal practice in Pakistan
[27] Otherwise, these losses will be wrongly assigned to the DISCO.

Where:

- $E\_BPC_{assigned,h}$ is the energy assigned to the BPC, for such particular hour, referred to the transmission network.
- $E\_BPC_{metered,h}$ is the energy actually metered at the BPC's CDP, which has been obtained using the SMS system.
- $DistLoss_h$ is the standard distribution losses coefficient, for the corresponding DISCO, as per the latest tariff determination.

13.2.3.2. Assignment of the corresponding energy to each Market Participant

In those cases, in which there are one or more CDPs embedded in the distribution network, the energy metered at the CDP corresponding to the transmission network shall be divided among all these market participants, using following procedure:

- The energy assigned (injected) to the generators (CDPs with positive balance) will be assigned to them. In this case the metered and assigned values will be the same;
- The energy assigned (extracted) by the BPCs (or other eligible customer) will be assigned to such BPC, calculated using the procedure described in the previous sub-section; and
- The energy assigned to the DISCO[28] will be calculated as the metered value at the CDP, plus the energy produced by generators, embedded in the distribution network; minus the energy assigned to the BPCs embedded into the distribution network.

$$E\_Gen_{i,h} = E\_Metered_{i,h}$$

$$E\_BPC_{j,h} = E\_BPC_{assigned_{j,h}}$$

$$E\_DISCO_h = EDEM_{metered\ CDP\_final,h} - \sum_j E_{BPC\ j,h} + \sum_i E\_Gen_{i,h}$$

Where:

- $E\_Gen_{i,h}$ is the energy assigned to the generator *i*, which is connected to the distribution network, in hour h.
- $E\_BPC_{J,h}$ is the energy assigned to BPC j, which is connected to the distribution network, in hour h
- E_DISCO_h is the energy assigned to the DISCO, which is connected to the transmission network, in hour h
- $EDEM_{metered\ CDP\_final,h}$ is the energy actually metered at the corresponding CDP.

These assigned values, in the case of the DISCO or BPCs will be later on uplifted using the methodology described in *sub-section 13.2.2*.

13.2.4. Uplift of demand values to take into account the Transmission Losses

Finally, the demanded energy, assigned to Market Participants, will be uplifted to consider the losses in the transmission network.

$$E\_Gen\_final_{i,h} = E\_Gen_{i,h}$$

[28] Assuming that the CDP at the transmission level corresponds to a DISCO, which is usually the case.

$$E\_BPC\_final_{j,h} = E\_BPC_{j,h} * \left(1 + \frac{Uplift_{TransLoss,h}\ \%}{100}\right)$$

$$E\_DISCO\_final_{h} = E\_DISCO_{h} * \left(1 + \frac{Uplift_{TransLoss,h}\ \%}{100}\right)$$

13.2.5. Balancing Mechanism for Energy

The Balancing Mechanism for Energy will be performed in the way described in previous sections, but using, for each hour, the adjusted demand ($EDEM_{final,h}$) instead the metered (or calculated) one.

13.2.6. Yearly (or monthly) Reconciliation

At the end of the year, or the month if NEPRA decides to implement monthly caps, the MO will determine the actual amount of losses of NTDC, simply adding the total transmission losses of every hour of the period. This value will be transformed in a percentage of the total energy transmitted by the transmission network, dividing it by the total energy injected into such network. If this value is below the allowed cap nothing additional will be done. If it is above, NTDC shall purchase the additional energy.

If this is the case, the MO will invoice NTDC for such energy, utilizing for such purpose the average marginal price of the energy over the considered period. This average could be either an arithmetical average or an energy weighted average, using for such calculation the total energy injected into the transmission network every hour. The most appropriate method will be analysed and determined during the implementation phase.

The MO will determine the share of the previously determined amount among all market participants which represented demand on a pro-rata basis, considering the total energy demanded during the whole period (initially the whole year).

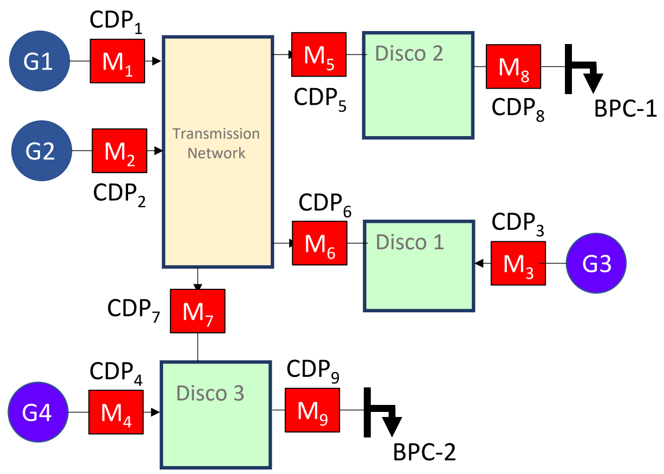
The MO will include the calculations and the resulting amounts (invoiced or discounted) in the last settlement statement of the year.

13.2.7. Calculation Example

The above described methodology can be better illustrated by the following example:

Suppose a small system with 4 generators (two of them connected at the distribution level), 3 DISCOs and 2 BPCs (both connected to the distribution network).

Following figure depicts the system along with the metering locations and the values registered by such meters at a particular hour h.



Metered Values		*NEPRA approved Losses*
M_1 = 120 MWh (injected)	M_6 = 50 MWh (extracted)	L_{D1} = 7%
M_2 = 90 MWh (injected)	M_7 = 84 MWh (extracted)	L_{D2} = 8%
M_3 = 12 MWh (injected)	M_8 = 10 MWh (extracted)	L_{D3} = 6%
M_4 = 21 MWh (injected)	M_9 = 15 MWh (extracted)	
M_5 = 70 MWh (extracted)		

Figure 12 – Example of the consideration of transmission losses for balancing purposes

13.2.7.1. Determination of the Energy Injected into the Transmission Network

The energy injected into the transmission network is calculated adding the metered generation at each CDP, connected to the transmission network, which has a positive balance during the corresponding hour.

In this case:

$$EG_{Tot,h} = E_{G1} + E_{G2} = E_{M1} + E_{M2} = 120 + 90 = 210\ MWh$$

Note: The generators G3 and G4 do not enter in this calculation, since they are not connected to the transmission network.

13.2.7.2. Determination of the Energy Extracted from the Transmission Network

The total energy extracted from the transmission network is calculated adding the metered values at each CDP, connected to the transmission network, which have a negative balance during the corresponding hour:

$$ED_{Tot,h} = E_{M5} + E_{M6} + E_{M7} = 70 + 50 + 84 = -204\ MWh$$

Note: As in the previous case, the BPCs BPC_1 and BPC_2 do not enter in this calculation, since they are not connected to the transmission network

13.2.7.3. Determination of Total Transmission Losses

Total system losses can be calculated adding the energy metered at each CDP connected to the transmission network (with their corresponding signs) In this example:

$$Tot_{Trans_{Loss}h} = (E_{M1} + E_{M2}) - (E_{M5} + E_{M6} + E_{M7}) = (120 + 90) - (70 + 50 + 84) = 6\ MWh$$

13.2.7.4. Total System Demand and Uplift factor

Total system demand is equal to the energy extracted from the transmission network, plus all generation that exists in the distribution network. In this case:

$$TotDem_h[MWh] = (|E_{M5}| + |E_{M6}| + |E_{M7}|) + (E_{G3} + E_{G4}) =$$
$$(70 + 50 + 84) + (12 + 21) = 237\ MWh$$

The uplift factor will be, therefore:

$$Uplift_{TransLoss,h}(\%) = \frac{TransLoss_h\ [MWh]}{TotDem_h[MWh]} * 100 = \frac{6.0}{237} * 100 = 2.53\%$$

13.2.7.5. Initial Assignment of the Energy Demanded to each Market Participant

To properly making the balance of each market participant it will be necessary, firstly, to refer the energies extracted by the market participants embedded into the distribution network to the corresponding CDPs located at the transmission network. These referrals will be done increasing the energy demanded by the BPCs embedded in distribution by the standard losses approved by NEPRA.

In this example:

$$ED_{BPC-1,h} = E_{M8} * (1 + L_{D2}) = 10 * (1 + 0.08) = 10.8\ MWh$$
$$ED_{BPC-2,h} = E_{M9} * (1 + L_{D3}) = 15 * (1 + 0.06) = 15.9\ MWh$$

The energy demanded form the system by each Market Participant, at each CDP belonging to the transmission network, which is "shared"[29] by several Market Participants, shall be done through balances of energy at each of these CDPs.

In this case:

$$ED_{Disco\ 1,h} = E_{M6} + E_{G3} = 500 + 12 = 62\ MWh\ (extracted)$$
$$ED_{Disco\ 2,h} = E_{M5} - ED_{BPC-1} = 70 - 10.8 = 59.2\ MWh\ (extracted)$$
$$ED_{Disco\ 3,h} = E_{M7} - ED_{BPC-2} + E_{G4} = 84 - 15.9 + 21 = 89.1\ MWh\ (extracted)$$
$$ED_{BPC-1,h} == -10.8\ MWh\ \ (extracted)$$
$$ED_{BPC-2,h} == -15.9\ MWh\ \ (extracted)$$

13.2.7.6. Determination of Final Energy Values (for each Market Participant)

The final values corresponding to each Market Participant, which will be used in the Energy Balancing Mechanism shall take into account the uplift on the demanded values to take into consideration the transmission losses. In this case, these values will be:

- For Market Participants with positive balance (generation point): The energy registered by the meter at the corresponding CDP
- For Market Participants with negative balance (demand): The energy calculated in the previous step, uplifted to take into account the system losses.

[29] A CDP at the transmission network which has "embedded" one or more CDPs at the distribution level.

In this case:

$$ED_{final_{Disco\ 1,h}} = ED_{Disco\ 1,h} * (1 + TotLoss_h\%) = 62.0 * (1 + 0.0253) = 63.57MWh\ (extract.)$$

$$ED_{final_{Disco\ 2,h}} = ED_{Disco\ 2,h} * \left(1 + Uplift_{TransLoss,h}\right) = 59.2 * (1 + 0.0253) = 60.70\ MWh$$

$$ED_{final_{Disco\ 2,h}} = ED_{Disco\ 3,h} * \left(1 + Uplift_{TransLoss,h}\right) = 89.1 * (1 + 0.0253) = 91.35\ MWh$$

$$ED_{final_{BPC-1,h}} = ED_{BPC-1,h} * \left(1 + Uplift_{TransLoss,h}\right) = 10.8 * (1 + 0.0253) = 11.07\ MWh$$

$$ED_{final_{BPC-2,h}} = ED_{BPC-2,h} * \left(1 + Uplift_{TransLoss,h}\right) = 15.9 * (1 + 0.0253) = 16.30\ MWh$$

$$E_{final_{G1,h}} = E_{M1} = 120.0\ MWh$$

$$E_{final_{G2,h}} = E_{M2} = 90.0\ MWh$$

$$E_{final_{G3,h}} = E_{M3} = 12.0\ MWh$$

$$E_{final_{G4,h}} = E_{M4} = 21.0\ MWh$$

As it can be easily confirmed, the amount of energy allocated to market participants which extracts energy from the system equals the energy allocated to those which injects energy. The BME and subsequent energy settlement, therefore, can be properly performed.

13.2.7.7. Transmission losses (in %)

The energy lost in the transmission network amounted 6 MW. In order to express it as a percentage, it has to be divided by the total energy transmitted through the transmission network (the energy which flowed through the network, not the total system energy).

In this case:

$$TotLoss_h(\%) = \frac{Tot_{Trans_{Loss}h}}{E\_Inj_{Tot,h}} = \frac{6.0}{120 + 90} * 100 = 2.94\%$$

For adjustment, same calculation as above will be used, but using total transmission losses (over the complete year) and total demand injected into the network, will be used to determine if the cap specified by NEPRA has been exceeded or not.

13.3. ALTERNATIVE APPROACH

An alternative approach to deal with the distribution losses could be that the DISCOs procure the losses on behalf of all consumers and recover the cost from them. This will require a separate calculation for the cost of losses and its incorporation in the wheeling tariffs. However, this approach seems more complex to apply than the proposed approached discussed above.

14. Functions of the Independent Auction Administrator

The Independent Auction Administrator has been introduced as independent body to provide different services primarily to DISCOs and also other participants in procuring new capacity to manage the transitions towards fully bilateral contract market. The Independent Auction Administrator (IAA) will be a state-owned company providing support to DISCOs in procurement on new capacity on competitive terms as per provisions of the applicable regulations. As per the recommendation in the approval of the CTBCM, this function can be assigned to AEDB and PPIB at the start of the market with necessary legal and regulatory adjustments. The future course of action will be decided as per conditions in the market.

The following sections describes the function of the IAA.

14.1. New Capacity Procurement

The Independent Auction Administrator (IAA) will provide services primarily to DISCOs for the new capacity procurement to cover the additional energy and capacity that each DISCOs needs to comply with its Capacity Obligation. The IAA will organize centralized competitive auctions for procuring the energy and capacity for aggregated need of all DISCOs. Once the auction process is completed, the actual procurement will be executed by each DISCO through signing the PPAs/EPAs with the awardees in proportion to their demand in the total procurement.

The rationale behind the combined procurement is that in individual procurements, the financially week DISCOs will be unable to find sellers to sign contracts with or will be exposed to very high-risk premiums. Therefore, in order to neutralize the individual DISCOs risks, the combined procurement mechanism is proposed for a transitory period until the risk profiles of all DISCOs is improved.

It is very important to emphasize that all procurements for regulated consumers either through IAA or bilateral by DISCOs as Last Resort Suppliers (after certain period when conditions are suitable) will be through competitive bidding. No costs should be passed to the end-consumer tariffs if competitive bidding is not followed unless the national policies establish something different.

The IAA will have the following main tasks regarding assisting in centralized power procurement of new capacity through contracts by DISCOs:

- Prepare and obtain the regulatory approval of the market-based contracts/PPAs / EPAs templates for the centralized auctions for procurement of new contracts (new generation) for DISCOs (in their role as Last Resort Suppliers), and coordination as applicable with relevant agencies on procedures and system to exchange data and clear allocation of rights and responsibilities of each one;
- Draft the standard bidding documents and submit as necessary for NEPRA review on compliance with regulation for competitive tariffs and ensure that costs of awarded contracts will be considered allowed power purchase costs of the DISCOs[30] to be recovered in regulated end consumer tariffs of each DISCO. Overall, the design of the auction and its procedures would need to comply with any regulatory requirement (NEPRA regulations or guidelines) to qualify as a competitive price and therefore allowed to pass through to regulated end-consumer tariffs.
- Calculation of the gap for each DISCO (demand forecast that is not already covered with contracts to meet Capacity Obligations) based on information provided by the DISCOs and in consultation

[30] As last resort suppliers

and consistency with demand forecast by each DISCOs and additional system long term load forecast provided by the Planner with assumptions and inputs as established in the Grid Code and other regulatory documents. The additional capacity requirements for the system will be established by the Planner and it will also prepare the least cost generation capacity expansion plan (IGCEP) as per provisions of the Grid Code and other regulatory documents.

- Prepare the Capacity Procurement Plan based on the calculated gap, taking into consideration energy policies of the Government, the Indicative Generation Capacity Expansion Plan prepared by the Planner and planned available transmission capacity as identified in NTDC Transmission Expansion Plan and complementary reports on transmission constraints and investments. This process will be undertaken as per provisions of the Procurement Regulations to be promulgated by NEPRA. The Capacity Procurement Plan will propose the quantities to be auctioned (e.g. capacity and/or energy) and whether the auction(s) will be differentiated by technology or technology neutral. Special auction may apply for strategic large hydro projects.
- Obtain the required regulatory approvals or clearance for the plan and auction documents as outlined in the procurement regulations
- Administer the competitive auctions for the approved Capacity Procurement Plan, finalizing it with reporting results and awarded bids, taking all regulatory approvals required according to the new capacity procurement regulations to be issued by NEPRA;
- If and as necessary, assist the DISCOs should any issue arise in the signing of the bilateral contract/ commercial PPAs/ EPAs with each generator that has been awarded in the auction. If the awarded bidder does not have a generation license, signing of the bilateral contracts will be conditional to obtaining the license from NEPRA till the licensing regime exists. This condition will end when the delicensing of generation companies is implemented as per provision of the Act.

14.2. CREDIT COVER

Credit covers will be required both for bilateral transaction and participation in the centrally administered markets by Market Operator. The IAA will assess the Financial Health of all DISCOs to assess their credit rating and their ability to provide credit cover. Additionally, IAA will assist financially weak DISCOs in arrangement of security covers. Some low performing DISCOs may not have the credit worthiness to obtain on their own the security cover required for contracts and for market participation. There will be a guarantee support scheme from the GoP to facilitate the eligible DISCOs their participation in the CTCBM. The IAA will be in charge of managing the required processes to get the guarantees granted to the eligible DISCOs. Eligibility will be approved by the MoE (PD) and will only apply to government owned DISCOs that are financially weak.

15. ADAPTATION OF POLICY AND REGULATORY FRAMEWORK

15.1. POLICY FRAMEWORK

Every country has certain priorities regarding their energy needs which are reflected in the respective policies that governs those sectors. These policies are adopted as per the changing priorities and circumstances. In order to transition the power sector towards competition, the current policy framework governing this sector will require certain adjustments to make the it aligned with the approved CTBCM Model. In this regard, an important action required is the formulation of a national level policy on market development. The promulgation of the National Electricity Policy (NEP) by the Federal Government pursuant to NEPRA Act is anticipated in near future which would provide guiding principles for Market Development in Pakistan.

In order to achieve consistency among the whole framework, other relevant GoP policies would also need to be reviewed and eventually amended if required. These policies address different segments of the sector such as generation, transmission and investment and the areas related to market design will be reviewed and amended as per requirements of the NEP and the approved market model. A gap analysis of the relevant policies shall be performed during the implementation phase to identity the changes that are required to achieve the objectives of the competitive market.

15.2. REVIEW OF LEGAL AND REGULATORY FRAMEWORK

The NEPRA Act (as amended 2018) gives an enabling framework for development of competitive market through creation of a licensing regime that is required for the operation of the competitive market. This regime introduced new licensees such as Market Operator, Electric Power Trader, System Operator and Electric Power Supplier. Moreover, under section 23A, the Act states that the Market Operator will centrally organized and administered the market and perform the settlement function. Similarly, the Act gives the basis for buying and selling of electric power services between multiple generators, traders, suppliers and BPCs through bilateral contracts.

International experience shows that electricity laws are enacted or adapted / modified in order to start the competitive electricity markets, however, in case of Pakistan, the law governing the sector (NEPRA Act.) has already been amended and the market model is designed in compliance to provisions of the Law. However, the current regulatory framework that include rules, regulations, codes and procedures, which have been designed for the current structure, will require modifications to address the challenges related to the competitive market operations.

Following are few indicative examples of the changes that will be required in the regulatory framework:

- The lack competition and choice are the reasons that generation prices are being regulated by NEPRA to balance the interests of consumers and investors. As new contracts for DISCOs (as Last Resort Suppliers) will be the result of a competitive procurement process (tender or auction), generation tariffs will become the result of competition. NEPRA has already issued the competitive bidding tariff regulations that provides a framework for competitive mode of procurement of generation assets. All such existing regulations will be reviewed, and new regulations may be issued by NEPRA to regulate or set guidelines for the competitive procurement process for new contracts for DISCOs, and to establish the standards and procedures for new power procurement costs to be passed through to the regulated tariffs

- The Balancing Mechanism costs resulting from competition for dispatch (SCED) and availability of generation will also be part of DISCOs power procurement costs, and the regulatory framework will need to be adjusted to reflect this in regulated electricity tariffs.
- Currently all generators selling to the DISCOs can only sell through regulated tariffs. In the future market, the regulatory framework should not create any barriers for generators, trader and Competitive Suppliers to negotiate conditions and prices for their bilateral contracts. The tariffs of generators selling to the DISCOs will be determined through competitive procurement process being regulated by NEPRA.
- The conceptual design of the competitive market model (CTBCM) is based on bilateral contracts between buyers and sellers and Balancing Mechanisms, which implies that different DISCOs may have different power purchase costs and the components of the costs will differ. One of the cost components will be the result of the allocation of the existing contracts to the DISCOs, another component will be the cost of new bilaterally contracted generation and a third component will be the result of participation in the balancing mechanisms. The end consumer tariff methodologies shall be adjusted to take into consideration all these cost components in future.
- Review and amend the Market Operator Rules to harmonize these with the approved CTBCM Model and the functions assigned to the Market Operator under NERPA Act (as amended 2018).

Under the amended NEPRA Act, promulgation of Rules is the competency of the Federal Government and all existing rules related to the wholesale market will be reviewed. Moreover, new Rules also need to be developed that are required for the completeness of the framework. Similarly, the existing regulation related to the competitive wholesale market will be reviewed by NEPRA to identify changes that are required to be done in the existing covenants and recognize the new regulatory documents in connection with the approved market model.

15.2.1. Codes in the CTBCM

For the implementation of CTBCM, the existing codes need to be revised and new commercial code for the Market Operator will be established that will govern the functions of the MO and define rights and obligations of the market participants and service providers.

15.2.1.1. New Market Code and Existing Commercial Code

A new code, the Market Code (Commercial Code for MO) shall be developed to set the objectives, principles, procedures, rights and obligations of the market participants and service provide and a comprehensive framework that will govern the functions of the Market Operator. Such Market Code will cover the details and requirements of settlement process including the market balancing pricing, the market settlement period and process to enable prior verification and comments by Participants (Preliminary Settlement document and final). It will also include provisions and procedures for calculation of energy and capacity for each Participant, ensuring Capacity Obligations, Balancing Mechanisms; contract information and contract register; market operation fee; market payment systems and credit covers.

The CPPA-G will develop a draft for such Market Code which will be submitted to NEPRA for review and approval. The Market Code will be complemented by market standard operation procedures covering detailed processes and formulas, and standard forms. The Code and the market procedures will be made public on the Market Operator website.

Additionally, the existing Commercial Code will be amended to reflect the provisions that will govern the functions of SPT as per approved market design, removing the clauses that relate to the function of the Market Operator. This amended code will be submitted to Commercial Code Review Panel (CCRP) for review and the recommendations of CCRP will be submitted to NEPRA for approval.

15.2.1.2. GRID CODE

The Grid Code will require amendments in order to incorporate and take into consideration matters in the market design relevant to the Grid Code (mainly operational planning and dispatch, generation availability commitment, and demand control), and to reflect applicable system security constraints and required operational planning studies and ancillary services, software, communication systems and SCADA. A gap analysis will be performed to identify the required areas and to make necessary adjustments.

It is recommended that the Grid Code be complemented with standard operational procedures with details for implementation, such as on operational planning, generation scheduling, demand control, availability testing, dispatch and real time operation. The Grid Code will all amendments and operational procedures should be made public on NTDC website and the System Operator website.

16. IMPLEMENTATION OF CENTRALIZED ECONOMIC DISPATCH

The **System Operator** will follow the Grid Code in implementing the operational planning (demand forecast, power system studies to determine system constraints, etc), generation scheduling and dispatch, scheduling of international interconnections, allocation of reserves and other ancillary services, and real time operation. Irrespective of the type of contracts and payment modes established in the contracts, the SO will dispatch the generators based on their variable generation costs (no fixed costs included). The Scheduling and Dispatch Code (SDC) code will be reviewed to incorporate the necessary elements of the market design. The results of the generation and import schedule planned (economic dispatch) for the next day will be published the previous day (in advance, the daily plan report) by the SO on its website and sent as electronic data to the MO. After the end of each day and as part of the daily operation report, the SO will publish on its website any change in the dispatch including the final agreed hourly exchange schedule (import) in each international interconnection.

> **Note**: The SO does not have a role in the balancing mechanisms, as these are trading arrangements administered by the MO. The SO has, instead, the critical role of the economic dispatch within system security constraints, ensuring transparency, adequate systems and software and compliance with the Grid Code.

Additionally, the SO will be responsible to manage the ancillary services through the existing fleet without any additional compensation from the market in the initial stage (ancillary services shall be paid through contracts by the demand).The rationale is that, in the initial stage of the market, almost all of the market will be supplied through the legacy PPAs and ancillary services are already a mandatory part of those PPAs. So, the cost of these services will be paid by the regulated consumers and will not be charged to other market participants. In exchange, the parties to the bilateral contracts will also provide ancillary services and will not charge the market for that. However, in future, when the free market share becomes significant, the compensation for ancillary services can be introduced, and the participants will pay separately for the ancillary services charges.

As the economic dispatch is based on variable cost of generation, a mechanism will be developed at the SO level to check the validity of information received from generator that are party to the bilateral contracts. If the information received is incorrect, then it will be replaced with the standard values being determined by the SO based on his own estimates. A detailed SOP will be developed to perform this verification process.

The main objective of the centralized economic dispatch is to ensure least cost generation in the entire system, however, in its implementation, there are some arbitrage opportunities for the retiring plants who have recovered their fixed costs and have very low efficiency. In order to avoid this, there are two options:

- To introduce efficiency caps in the policy
- To leave them on the market forces, meaning that when there is not any surplus capacity, these plants will be producing more energy and hence will become very expensive to operate.

The best option will be decided during the implementation phase.

17. Market Operator and Governance System

17.1. Requirements and Credibility

To avoid conflict of interest and to be perceived as a credible administrator that provides non-discriminatory market administration services, the Market Operator must be a company that does not have commercial interests in contracts or supplier business. The markets administered by the Market Operator affect the costs and revenues of Participants. Therefore, the Market Operator cannot be a party (or sign) in contracts or PPAs/EPAs, in particular as contracts may have imbalances with the clearance and settlement mechanisms administered by the same Market Operator.

The credibility of the market and the ability to attract participation depends significantly on the capabilities and credibility of the Market Operator. With that consideration, the credibility and performance of the Market Operator will be measured by the following requirements and results:

- The Market Operator is independent of commercial interests of Participants and is not involved in contracts/PPAs/EPAs as a party or signing the agreement,
- Accuracy, transparency and quality control in administering commercial information, capacity market and calculation of imbalance prices;
- Efficacy and timely administration of the settlement and payment systems, and credit cover to guarantee a sustainable and credit worthy market.
- Market Operator website that provides clear and useful information, regularly updated.
- Open consultations, and forums, committees and/or panels to interact with Participants, and for communication and capacity building with Participants, other stakeholders and the public in general.

17.2. Functions

The main functions and responsibilities of the Market Operator will include the following:

- Admission of Participants, including signing the Market Participation Agreement, and suspension and cancellation of Participants;
- As part of the admission process, registration of the Participant, including registration of settlement metering systems (to identify metered energy to be used to calculate imbalances) taking into consideration location of meters and activities of the participant (taking into consideration for example that a Participant that is an aggregator may represent more than one demand or power plant);
- Sign a Market Participation Agreement with each Participant establishing rights, responsibilities and obligations, including the obligation of the Participant to provide credit cove.;
- Calculation of energy imbalance prices, and determination of firm capacity, hourly imbalance prices;
- Calculation of energy and capacity imbalance quantities for each Participant;
- Calculation of monthly transmission use of system charges and market fee;

- Balancing Mechanism Settlement on a yearly basis (including transmission charges and market fee), and issuing payment instructions on behalf of Participants [and administration of market payment system].
- Administration of credit cover/collaterals for transactions in the Balancing Mechanism, transmission charges and market fee: determination of amount required, and call/use of the credit cover in case of payment not completed by market payment deadline.
- Administration of market payment system (weekly and monthly)
- Administration of the procedure to receive complaints or observations to settlement documents, and resolve the complaint;
- Administration of a dispute resolution mechanism for settlement complaints that have not been mutually agreed and resolved.
- Implement, update and maintain the Contract Register.
- Responsible for Information disclosure of market results (made public through its website)

17.3. Market Credit cover of Participants

A Participant Supplier or a BPC can potentially buy energy in the Energy Balancing Machining or Capacity in the Capacity Balancing Mechanism if part of its energy or capacity requirement is not covered by contracts. A Generator that has a selling commitment in a contract may potentially buy in the energy or capacity Balancing Mechanism to cover the contracted energy it does not generate or committed availability. A trader can also potentially become a buyer in the balancing mechanisms to meets its contractual obligations. Therefore, all Participants can be buyers in the Balancing Mechanisms. For the market to be perceived as credible by investors and BPCs, it is necessary to limit the payment risk in the shared administered Balancing Mechanisms: address the risk that a Participant refuses or is unable to pay in a timely manner for the imbalance charges. The Market Operator will set credit requirements to reduce the risk of non-payment and establish mechanisms to recover from a Participant the costs of any bad debts that occur despite the credit requirement.

- Typically, in a competitive wholesale electricity market, the level of credit cover required from a Participant depends on the outstanding or potentially outstanding payments in the settlement of the markets and charges administered by the Market Operator. In the proposed market design, the payments would include imbalance energy and capacity charges, transmission use of system charges and the market operator fee.
- Each Participant must provide and maintain a Credit Cover, as a cover for its payment risk. This cover may be a cash deposit in an interest-bearing escrow or trust account, or an irrevocable direct pay Letter of Credit, or other acceptable payment guarantees.

17.4. Market Settlement

The settlement procedures and payment system administered by the Market Operator will be weekly (provisional) and monthly (final). At the end of each week, the Metering Services Providers will submit metered energy and the System Operator will send to the Market Operator information about available capacity and dispatch on daily basis (informing the results of the previous day). With this information and the Contract Register, the Market Operator will calculate energy imbalances and capacity imbalances (if applicable) of each Participant:

- At the end of each week (possibly each day in the case the remote reading of settlement meters is enabled on all meters), the Market Operator will calculate the imbalances of each Participant and prepare the provisional weekly settlement document, covering energy and capacity imbalances (if capacity imbalance is applicable), inform Participants, and administer the payment system; this provisional weekly settlement document will be circulated to all Participants.
- At the end of each month, the Market Operator will receive the final monthly data (hourly energy, daily capacity, availability, etc.) and conciliate the final monthly settlement, taking into consideration payments made by or received in the weekly provisional settlement for imbalances, and including additionally monthly transmission use of system charges and market fee. The monthly settlement will also include any adjustment resulting from resolving complaints and disputes to previous settlement. The settlement document sent to each Participant will include all the detailed data required for the Participant to review and verify the settlement.
- The Market Operator will administer the market payment system based on bank account and monitor compliance with market payment obligations. This payment system will not include payments in contracts, which will be bilateral.

17.5. Market Governance System

The implementation and success of efficient and competitive electricity markets with multiple Participants, a mix of private and public ownership, and with the goal of attracting investors accepting market risk, has as an essential requirement which is transparency of market data. Disclosure of inputs, plans and results of the market demonstrate that the rules, codes and other regulations have been implemented consistently, and that the Market Operator is providing non-discriminatory services ensuring a level playing field for all Participants. This is a required condition in order to enable the development of effective competitive and fair prices.

Information disclosure of market results promotes competition and adequate investment. Information made public through the Market Operator's website will demonstrate to investors, consumers, other stakeholders and the public in general that the market is credible. Electricity market reform can fail due to lack of liquidity, transparency and effective competition. The Market Operator needs to administer trading and settlement environments and deliver services that attract participation, and therefore promotes competition. The administration of the market will affect investors, power companies and costs transferred to consumers. Lenders must consider that the exposure to the market is a predictable and a manageable risk.

The Market Operator needs to demonstrate and be perceived as credible and trustful administrator of the organized centrally administered market mechanisms and settlement systems. This is an essential requirement for the market environment to be considered attractive by Generators, Traders, potential BPCs and Suppliers. To address these concerns, the Markey Operator will administer a data platform on its website for Participants (including settlement documents), and an open data platform with information (data and reports) to the public, including among others demand (forecasted and actual) and Capacity Obligations, level of contracting (percentage covered by contracts and percentage covered by Balancing Mechanism), generation and availability, balancing prices (energy and capacity), and payment risk.

In addition to data platforms to build transparency and credibility of the market and settlement system, there will be governance arrangements based on international good practices, for the Market Operator's accountability and ensuring non-discrimination. The Board of the Market Operator will include members nominated and appointed as their representatives by the categories of Participants and Services Providers. The nomination will come through associations of market participants and service providers which should be established before the start of the CTBCM. The Board will also include at least two independent members representing consumers. The members of the Board must be independent and with relevant skills and expertise. The Market Operator and the Market will benefit from an experienced Board reflecting the mix of interests and knowledge of the different stakeholders.

The Market Operator will have a Governance system to ensure transparency and accountability. To benefit from expertise of power companies and the views and experience of consumers and Competitive Suppliers, the Market Operator will organize and maintain permanent panels or committees, and ad hoc working groups, chaired by the Market Operator and with staff of relevant Participants and services providers. In particular, there will be:

- a settlement working group to discuss and look for measures or decisions / agreements on issues in the settlement process (timeliness, quality and accuracy, different interpretations, etc) and payment system.
- a Market Review Panel to meet periodically and review the adequacy and effectiveness of the operation of the market and its rules/code, any issue on interpretation or non-compliance, and amendments to the rules/codes or procedures.

There will be annual (or every two years) operational audits by independent consultants to assess implementation, including compliance and behaviour of the Market Operator, the System Operator and Participants. The operational audit reports will include recommendations on improvements and will be submitted for comments by the Market Review Panel and published on the Market Operator website.

Additionally, the Market Operator will carry out capacity building to level the knowledge basis, facilitate integration to the market, attract new participants and the interest and credibility of investors.

17.6. IT INFRASTRUCTURE

Competitive market is all about transparency and data. The Market Operator must ensure that all participants have access to reliable and accurate data to provide level playing field. Also, it is very important that the MO establish processes that are automated to the extent feasible and free from human intervention especially the commercial metering data. The MO must be accurate and response quickly on the issues of the centrally administered market.

In order to achieve the transparency and efficiency, it is imperative that state of the art IT infrastructure is established at MO in order to perform its function in a more organized and automated manner. As stated above, the MO must establish transparency and data sharing portals in a organized manner so that participants are able to access data and make their analysis.

18. PARTICIPATION OF KE IN THE MARKET

As discussed earlier, KE has been operating as vertically integrated utility and has been granted generation, transmission and distribution licenses by NEPRA. Each of the license of KE has clauses for that mandates KE to participate in the competitive trading market. The transmission license of KE specifically states that in future, KE shall perform its function as per provision of the approved CTBCM model.

Therefore, with the introduction of the CTBCM, there are two basic aspects that are important to mention

- **Allocation of fixed Capacity and Energy from the legacy PPAs:** Similar to all other DISCOs, a portion from the legacy agreements will be commercially allocated to KE. However, the difference with all other DISCOs is that KE will be allocated a fixed share in quantity (MW and MWh) not in terms of percentage. KE will be allowed to have bilateral contracts and all future procurement of KE shall be subject to a least cost generation and transmission capacity expansion plan developed for the KE system.
- **Purchasing as Supplier form the Market:** KE will be registered with the Market Operator as Supplier (Last Resort) in order to purchase electricity from the market to meet the demand of its regulated consumers. However, it will have the opportunity to sell its surplus generation (if any) in the market.
- **KE status as integrated utility:** KE will remain as integrated utility and an appropriate mechanism will be devised during the implementation phase to enable bilateral trade in the KE served area.

Integration of KE in the Market: There can be multiple options for integration of KE in the Market. Some of these are discussed as under:

- **Option 1:** KE remains as integrated utility and trade in the market as import and export.
- **Option 2:** KE remains as integrated utility for certain period and trade in the market as import and export, however, a clear plan is established to integrate it into the market and one single market is established. This will require enhancement of the transmission network at the interconnection.
- **Option 3:** Two separate markets are established with clear boundaries for import and one market operator makes settlement in both markets.

However, the most suitable option will be decided during the implementation phase taking into account the provisions of the Act. and the concession agreements of KE.

19. CONSIDERATION ON TRANSITION TO COMPETITION

Transition from Vertical Integration or Single Buyer regime towards competition is not a simple process. To be successful, it requires careful analysis to properly design instruments to achieve full advantage of the competition, providing a levelized playing field for existing players as well as new entrants. The pace of the market development shall also be monitored in order to avoid any adverse impacts due to inflexibilities or previous commitments of the legacy structure. Some aspects that will require due consideration are indicated below:

1. **Tariff Structure:** In a Vertically Integrated Utility (VIU) or Single Buyer Models, normally the tariff structure is designed in such a manner that it comprises of all the system costs, including generation, transmission, distribution, ancillary services, etc., in a single tariff without being absolutely necessary[31] clear separation of each cost component. Despite the Regulator (and the Utilities) will have the information on these components, the methodologies applied give no special significance to such separation, since it is the total cost that needs to be reflected in the end consumer tariffs. This is particularly important in Pakistan since the end-user tariffs are heavily energized[32] despite that many of the involved costs are related with the capacity. When markets are opened and consumers are given choice to choose their suppliers, the structure needs to be adapted because now the consumers are no longer procuring from the host utility all the mentioned components. In competitive markets, different players provide different services i.e. the transmission and distribution companies provide the wire service to transport electricity, the System Operator is responsible for security and reliability of the system and the Market Operator is responsible for the commercial settlements in the market. Also, there will be players in the market with no physical assets. Therefore, it is mandatory to amend the tariff structure to establish clear bifurcation of the costs of different services, the determination of such costs and the charging mechanisms.

2. **Legacy Inflexibilities:** The legacy of the market shall also be taken into consideration while transitioning towards competition. The inflexibilities of the legacy structure may create certain additional costs with the introduction of the competition which shall be recognized and properly addressed. For example, the VIU or the Single Buyer may have contracted enough capacity on behalf of the consumers with inflexible terms and conditions for significant time in future, and with the introduction of competition, if the demand exits its portfolio at a very fast rate, it will create burden on the VIU or the Single Buyer, which it could be unable to support or, otherwise, they will be transferred only to those consumers which are not receiving its supply from Competitive Suppliers. The pace of the market shall be set as per the ground realties of the market and proper analysis shall be undertaken to avoid any adverse impacts.

3. **Cost of Losses:** In electricity system, losses are an inherent part of the electricity supply chain and shall be recognized as component of the total cost of supply. The total energy generated in the system shall be paid which is equal to the actual load and the losses in the system. Therefore, this shall be established as separate cost component and its determination and charging mechanisms shall be worked out.

4. **Providing a Level Playing Field:** In order to reap its benefits, competition shall be introduced on a level playing field. No player shall have priority rights or undue advantage over other market players. In Pakistan, end consumer tariffs of VIU (KE) and DISCOs, are not completely cost reflective. These tariffs incorporate relevant cross-subsidization to achieve other social and economic objectives. Such cross subsidization creates important issues for providing a level playing field when competition is introduced. Therefore, a careful analysis is required to understand all such cross-subsidization among different categories of consumers and to remove

[31] Although advisable

[32] The different cost components are referred to the energy consumed and not necessarily to the peak load

any inconsistency which may create undue incentives for some players in the market. However, the cross-subsidization shall not be confused with the incentives given to market players to foster competition.

5. **Removing arbitrage opportunities:** The basic principle of the competitive electricity market is that everybody pays for their consumption, and everybody is paid for their delivery. With the introduction of competition, some arbitrage opportunities may be created due to decisions taken in the past. Such arbitrage opportunities will be beneficial for only certain players while some others would be bearing the cost. Therefore, it is very critical to look for such loopholes in the design of the market and provide proper mechanisms to address these.
6. **Metering Systems:** The metering system should be suitable for the gradual market opening to more consumers. This is so, because the energy traded in the wholesale market is done on hourly basis[33] and not all the meters installed at end-customer boundaries are prepared for such kind of trading. Although it is not absolutely necessary that all the meters be changed to increase the eligibility base[34], appropriate procedures shall be put in place to properly account for the energies which are traded at different time periods[35].

[33] The balancing mechanism is performed in hourly (or sub-hourly) basis
[34] There is significant international experience in market opening without changing all the meters in the system
[35] I.e. creating standardized load profiles to transform the energy consumed by end-customers in monthly basis to energies demanded in hourly basis.

ANNEXURE-I: LIST OF FUTURE DELIVERABLES

Sr. No.	Deliverable
Codes	
1	Amendments in Grid Code
2	Commercial Code for SPT
3	Commercial Code for MO
4	Amendments in Distribution Code (Metering and Planning Code)
Agreements	
5	Draft Connection Agreements
6	Amendments in PPAAs
7	PSODA
8	Draft Templates of PPA
9	Preparation of Market based contracts templates by PPIB and AEDB
10	Market Participation Agreement
Policy/Rules and Regulations	
11	Concept Papers for development of Rules and Regulation
12	Procurement Regulations
13	Balancing Regulation (if needed)
14	Drafting of other Rules and Regulation
15	Amendments in policies
Methodologies/Mechanisms	
16	Methodology for calculating firm capacities
17	NPCC SOPs
18	Methodology for calculation of credit cover requirements for Balancing Mechanism
19	Mechanisms for treatment of late payments (may be part of the market code)
20	Mechanism for Credit Covers or Government Guarantees to be developed by PPIB and AEDB
21	Marginal Price Methodology
22	Firm Capacity Certification Mechanism
23	Mechanism for allocation of transmission and distribution losses
24	NTDC Losses Target Revision to monthly values
SOPs/Others	
18	Preparation of Bidding Documents by PPIB and AEDB
19	Metering SOPs
20	Procedures for preparation of preliminary and final settlement statements

ANNEXURE-II: CONSULTATION PROCESS AND STAKEHOLDERS COMMENTS

In compliance to the direction from NEPRA to prepare a Detailed CTBCM Implementation Roadmap in consultation with the stakeholders, CPPA-G organized a series of consultative sessions at different organizational levels from Dec 26, 2019 to Jan 4, 2020 and Jan 10, 2020 inviting participants from NEPRA, NTDC, NPCC, PPIB, AEDB, DISCOs, K-Electric, IPPs and independent consultants. During the consultative sessions, different aspects of the detailed design of CTBCM were deliberated upon with the participants of the consultative sessions. The sessions were very interactive, and opportunity was given to all participants to given comments and feedback on the proposed features of the CTBCM model. During the session, participants provided comments which were addressed by representatives of NEPRA and CPPA-G. A summary of the comments is presented below:

1. **Sovereign Guarantees:** It was argued that it is incorrect notion that sovereign guarantees issued in the power sector are having negative impact on the overall credit rating of the country and as such shall be removed or replaced by other types of guarantees. The participant was of the view that as these guarantees are not reflected on the Balance Sheet of Government of Pakistan (GoP), therefore, they have no impact on the credit rating of the country. It was argued that only the sovereign guarantees issued by the Ministry of Finance are reflected on the Balance Sheet of (GoP). The sovereign guarantees issued in power sector are a policy tool used by the government to reduce the overall risk and as such has no impact on the credit rating of the country. In this way, it shall be continued in future as well.

   Response:

   Other participants argued that these sovereign guarantees are accounted for as contingent liabilities by the credit rating agencies while evaluating the country risk of Pakistan. They argued that due to such kind of liabilities, the country risk of default becomes high and hence GoP borrowing becomes costlier. They argued that even if these are not reflected on the Balance Sheet of GoP as strategy, it is a known fact and the credit rating agencies considers these liabilities for the country risk profile evaluation.

   Conclusion:

   Participants agreed that sovereign guarantees are a burden for the country as well as the consumers and, therefore mechanisms shall be developed to improve the performance of the DISCOs so that investments can be arranged without the need for sovereign guarantees. It was discussed that it seems like with the removal of the sovereign guarantees, the prices will go higher, however, the competition will force the prices further down as observed in international markets and implementation of market reforms will reduce many market related risks and hence the returns demanded by the investors.

2. **Provincial Grid Company:** Participants asked about the functions and jurisdiction of the provincial grid companies whether NTDC will hand over its assets to such provincial grid companies in the respective provinces and how these will be treated in the CTBCM.

   Response:

   It was explained to the participants that NTDC will remain as the National Grid Company in the country and will own and operate its existing assets, and it will construct new lines as per its expansion plans prepared by NTDC and approved by NEPRA. The provincial grid companies will only be allowed to construct new lines as per regulatory process in their respective provinces to complement NTDC's role in the expansion of the network. NTDC will not hand over any of its assets to the provincial grid companies.

   Regarding the tariff of the provincial grid companies, it was explained that as Transmission is natural monopoly, so the rates and charges will be regulated by NEPRA. NEPRA will determine the use of network charge for all provincial grid companies which will be collected from the users of their network as per regulated procedures.

Conclusions:

Provincial Grid Companies will only complement NTDC in the expansion of the primary grid in the respective provinces and its use of network charge will be regulated by NEPRA.

3. **Transmission Network Unavailability:** It was asked that the transmission network unavailability risk for renewables is currently parked on the purchaser in the form of Non-Project Missed Volume (NPMV). How this risk will be covered in the CTBCM?

   Response:

   It was explained that the NPMV is offered to cover the transmission network unavailability risk for the investors under the current security package being offered by GoP to incentivize the penetration of renewables in the national grid.

   In future, the availability of the transmission network will be ensured through proper enforcement of the transmission performance standards of NEPRA. If the transmission company is performing as per the standards and some outages occur, then this risk can be borne by the investors. Also, as standard practice, the generators will make their due diligence before selecting a location in the transmission network and will properly asses all the risks. In any case, these aspects will be deliberated in detail during implementation phase. The existing RE based IPPs will have the same treatment as of today.

   Conclusion:

   In any case, whichever be the final decision regarding the NPMV, it should not be an unsolvable problem to implement the CTBCM. The existing RE based IPPs will have the same treatment as of today.

   Connection agreements subsequent to the Transmission Performance Standards will address the issues related to the transmission network availability.

4. **Creation of an Independent System Operator Model:** Participants enquired about the rationale behind separation of the System Operator function from the Transmission Network Owner (TNO) company and also the advantage of merging it with the Market Operator to create and Independent System Operator (ISO) model. Participants argued that as different models exist in the world where in some regions the System Operator and Market Operator are combined like US and Canada, while in other regions where the System Operator and Market Operator are two separate entities like EU and Turkey. Keeping in view this, what is the best model recommended for Pakistan?

   Response:

   It was explained to the participants that the rationale behind the separation of the System Operator (SO) function from the TNO is to be more focused on its strengthening as the SO has very important role to play in the market. However, the CTBCM can be properly implemented even if the SO function is housed in the TNO. In order to enhance confidence in the market, procedures will be established to enhance transparency through regular publishing of information related to system operations.

   Regarding the different institutional arrangements across different regions, it was explained to the participants that there is no standard practice and these arrangements are made based on the realities of the region and its legacy. In case of North American Markets, the ISO model has been successfully implemented as these markets are based on centralized economic dispatch.

In case of Pakistan, as the sector is already de-bundled and these different functions are performed by different entities. For the start of the market, it will be a distraction to change the institutional structure first and then implement the market. The ultimate goal for Pakistan could be the establishment of an ISO model where different inter-related functions are housed under one company to enhance coordinated planning and execution, that suits how the market is organized in Pakistan. However, this shall not be made a precondition to start CTBCM, and the market shall start with the current institutional structure in which different functions are performed by different entities.

Conclusion:

The ultimate goal could be the establishment of an ISO model; however, the market can be properly implemented with the existing institutional structure.

5. **Direct Procurement of DISCOs:** It was asked by the participants that what is the rationale behind combined procurement through IAA for all DISCOs in the initial stages of the market? Why it is not recommended that each DISCO individually procures Energy and Capacity for its own demand?

Response:

It was explained to the participants that transition from a single buyer model towards a fully bilateral contract markets needs maturity of different market players. Power procurement and management of the bilateral contracts is an intricate subject which requires cross disciplinary knowledge such as legal, regulatory, technical and commercial aspects need to be considered. There are two aspects that needs consideration while allowing the DISCOs to have bilateral contracts on their own.

1. **Technical Capacity:** CPPA-G has been managing the bilateral contracts for long period and has gained capacity and experience to negotiate terms and conditions with the IPPs. The DISCOs at this stage doesn't have the required capabilities and therefore, until the capacity building takes place, the procurement shall be combined through IAA for all DISCOs.
2. **Credit Rating of individual DISCOs:** Due to different credit rating of different DISCOs, the risk profile of each DISCO is different. Based on this, no investor will be willing to sell to the low performing ones or they might charge very high-risk premiums in selling to those lower performing DISCOs which will have negative impacts on its consumers. In order to neutralize this risk, the combined procurement is proposed to get an average price for the average risk of the whole market. Meanwhile, the government, as the owner of these DISCOs, is in the process of improving the performance of low performing DISCOs to make them credits worthy and then the procurement by individual DISCOs may take place.

Conclusion:

For initial stages of the markets, the procurement shall be done for the combined demand of all DISCOs through auctions run by IAA. Apart from the current initiatives, a plan shall be formulated by government to improve the performance of the low performing DISCOs and after the achievement of the required results, all DISCOs shall be allowed to have bilateral procurements individually.

6. **Force Majeure Events:** Participants asked about the mechanisms for treatment of Force Majeure Events in CTBCM?

Response

It was explained that the risk of Force Majeure will be addressed in the bilateral contracts being negotiated and signed by the parties. The standard templates prepared by AEDB and PPIB for procurement thorough auctions for the DISCOs will include provision on force majeure events and their compensation mechanisms.

Conclusion

This will be addressed in the bilateral contracts.

7. **Composition of the text of the high-level conceptual design report:** Some participants provided comments on the composition of the text of the high-level conceptual design of the report and highlighted that some tools like transparency and accountability are mentioned as objectives of the market model. They were of the view that the text may be rephrased to give more clarity.

   Response and Conclusion:

   It was explained to them that the objectives of the model highlight the critical aspects which will be addressed through different mechanisms. People can have different view about the arrangement of the text, but the overall concept and details are accurate to address different issues and it is complete in all aspects.

8. **Demand Projections, Aggregation and Supply Gap Assessment:** It was highlighted that the role of the IAA seems to be a planning agency from the text of the document which shall be clarified in the detailed design.

   Response and conclusion:

   CPPA-G agreed with the suggestion that this will be addressed in the detail design by giving more clarity to the role of the IAA and the role of the planner functions.

9. **Assignment of Existing Contracts:** It was argued by the participants that the legal assignment of the contracts signed or administered by CPPA-G to DISCOs seems more ambitious rather than realistic which shall be reconsidered.

   Response:

   It was explained to the participants that the idea behind such assignment was to put pressure on the payment discipline by DISCOs, however, based on the feedback received during EMP-2018 and through other consultations, the idea of legal assignment to DISCOs was replaced with only commercial allocation which will have no legal implications for the IPPs. The same has been reflected in the CTBCM approval by NEPRA. Later on, when the performance of the DISCOs be improved and there is confidence in the market, the legal bilateralization can be considered based on the realities of the market.

   Conclusion:

   All existing contracts will be managed by the Special Purpose Trader (SPT) and will only be commercially allocated to the DISCOs.

10. **Procurement of Power from Imports**: It was mentioned that imports like CASA are currently procured by CPPA-G. What will be the mechanism for procurement from Imports? Currently there is import from Iran in QESCO served area, which is also procured by CPPA-G, what would be the treatment of such kind of imports in CTBCM that only serve one DISCO? Also, how the power procured by the DISCOs from SPPs will be incorporated in the CTBCM?

Response:

Regarding import of power from neighboring countries, it was explained that the CTBCM will provide a transparent mechanism so that participants are able to import power as per import regulations from NEPRA and sell it in the market. The design of the CTBCM provides a complete framework for imports.

Regarding the import from Iran in QESCO served area, it was explained that initially, for the DISCOs there will be combined procurement for the demand of all DISCOs through IAA. However, if there are imports in an isolated area (not connected to the national grid being served by a DISCO), the possibility of allocating such imports to the individual DISCO shall be evaluated and ultimately decided by NEPRA.

Regarding the procurement from existing SPPs by the DISCOs, it was explained that these transactions are outside the wholesale boundary of the market and will be taken care by the SPT.

Conclusion:

All the aspects highlighted by the participants are covered under the market design of CTBCM.

11. **Metering Service Provider:** It was highlighted by the participants that the wire business of the DISCOs will be responsible for the metering service as well in the distribution network, so there is a dire need for automation of the metering service. Participants highlighted that AMR systems has been installed in MEPCO and HESCO areas and IESCO has also been planning to install these. It was emphasized the metering infrastructure shall be fully automated.

Response and Conclusion:

Participants agreed that this is very important for DISCOs, and all DISCOs shall implement the AMR system to improve the metering data collection.

12. **Capacity Obligation & New Generation Capacity Procurement:** It was argued by the participants that why there are capacity obligation on BPCs what they have to inform the Market Operator about their contracted capacities when they are able to watch their interests on their own?

Response:

It was explained that the capacity obligations are introduced to ensure the security of supply in the system and to make sure that each participant is contributing to it. As the market starts, some players may not behave rationally due to lack of understanding of the dynamics of the markets and commits mistakes which jeopardize the security of the whole system. In order to avoid such adventurism at the start of the market, capacity obligations are introduced for all participants including BPCs. Once the maturity in the market is enhanced and the participants start to understand the dynamics of the market, the capacity obligations with be reduced gradually to give rise to more short-term trading by the participants.

Also, the information on contracts is important for the provision of the last resort service by the DISCOs i.e. if the BPCs are not procuring through contracts, then the DISCOs must manage sufficient capacity to supply their load.

Conclusion:

Capacity Obligation shall be in place for all participants including BPCs at the start of the market and shall gradually be reduced depending upon the maturity of the market players.

13. **Mechanism for Pipeline Projects:** Participants enquired about the proposed mechanism for the procurement of the pipeline projects which will be procured in near future. It was asked that whether these will be procured under the existing framework or will these be procured under the proposed mechanism in CTBCM?

    Response and Conclusion:

    It was explained to the participants that all green field projects in future will be procured under the proposed mechanism of CTBCM. Regarding the projects in pipeline, if the projects have achieved significant milestones before the commencement of the CTBCM and are committed under the existing regime, then these will be assigned to the SPT and will be commercially allocated to the DISCOs as all other legacy PPAs. However, projects with no commitments from the GoP will be procured under the proposed mechanism after the commencement of the CTBCM.

14. **Mechanism to avoid arbitrage opportunities:** Participants argued due to adequate capacity already being contracted for the regulated consumers and the recession in demand, there are some arbitrage opportunities of the retiring plants to avoid capacity payments and to procure energy from the market and very low marginal prices.

    Response and Conclusion:

    It was explained that due to adequate capacity in the system, such kind of arbitrage opportunities do exist in markets. In order to avoid these, the policy makers and regulators introduce certain measures through policy and regulatory tools. The measures include clear policy on retiring plants whether to allow them or not and application of efficiency caps. Similar measure will be proposed for the CTBCM as well in order to provide a level playing field and that the costs are equally shared. It is important to mention here that once the market achieve equilibrium, such kind of opportunities are automatically wiped out.