3/4/2020

Fatima Energy
Limited
A Fatima Group Company

FEL/NEPRA/020420/1009
2 April 2020

ADG(Lic)
LA(M&E)
SA (Tech)

The Registrar,
National Electric Power Regulatory Authority ("NEPRA")
NEPRA Tower, Attaturk Avenue (East)
Sector G-5/1, Islamabad

Subject: **Detailed Design Report and Implementation Roadmap of Competitive Trading Bilateral Contract Market (CTBCM) Submitted by CPPA-G**

Reference: NEPRA letter no. NEPRA/ADG(Lic)/LAN-100/7979-23 dated 10 March 2020.

Dear Sir,

Pursuant to NEPRA letter no. NEPRA/ADG (Lic)/LAN-100/7979-23 dated 10 March 2020 vide which comments were invited on CTBCM reports submitted by CPPA-G.

We are pleased to submit comments attached to this letter for review of the honorable Authority. We are available for any further clarification required in this matter.

Kind regards,

For and on behalf of
FATIMA ENERGY LIMITED

For n.a.p.
- SA (Tech)
- ADG (Lic)
- LA (M&E)

Copy to
MF

06.04.20

CC:
- Chairman
- M (Lic)

CHAIRMAN
Dy No. 2632
Date: 02-04-2020

Fazal Ahmed Sheikh
CHIEF EXECUTIVE OFFICER

Enclosure: FEL comments on CTBCM reports submitted by CPPA-G.

Registrar

REGISTRAR
Dy. 5520
Date 06-04-20

	CTBCM Point	FEL Comment
	<u>NETWORK LOSSES:</u> 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). *(Ref: 13.2)*	a) Examples are available where only a small % as fixed cost in the form of wheeling charges were recovered from wheeler of power in India and losses were not charged for wheeling of power during the initial period. Similar practice was followed in other countries as well to maintain certain pool of wheeling participants. After certain maturity period, regime was shifted to include technical network losses for wheeling participants. b) Consideration shall be given to the fact that some of the participants may reduce overall system losses, example of UK market was shared to elaborate the point that participants contributing positively are given credit in performing wheeling obligation. c) Existing practice in wheeling regime should be continued for a period of at least five years so that private sector is encouraged to enter wheeling regime in line with the incentives given to new industries setting up plants in economic zones. Once the aforesaid period is over, actual technical losses associated with the transmission line voltage to which it is connected through wheeling, as per international practice, may be considered on case to case basis. d) Financial or administrative losses, if any, shall not be passed on to network users unjustifiably because it will discourage the competition by giving undue benefit to DISCOs. e) While losses form part of the costs of wheeling, burdening customers with unreasonable amounts of losses (e.g. due to inefficiencies) or for losses associated with the retail business should be avoided. The loss level included for wheeling should be clearly defined and reflect only reasonable losses. To provide accurate pricing signals and encourage optimal location of new facilities, grid impact should play a role. f) It should be investigated by NEPRA whether it is technically and administratively possible to apportion losses to bilateral contract participants based on their impact on the grid given their small number. If not, postage stamp may be applied until nodal pricing becomes available. g) Only technical losses should be applied as those are associated with the "wire" business.

	CROSS SUBSIDY: In Pakistan, end consumer tariffs of KE and DISCOs are not completely cost reflective. These tariffs incorporate relevant cross-subsidization to achieve other social and economic objectives. Such cross subsidization create 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 any inconsistency which may create undue incentive for some players in the market. *(Ref: 16)*	a) Cross subsidy is a policy decision by GoP. Recent amendment to the NEPRA Act has specifically removed proviso to Section 22 which provided for cross subsidization of open access customers. From this amendment, intention of legislature is very clear that as we move towards open market there is no room for cross subsidies. b) A number of power markets don't impose cross subsidies on open access customers regardless to the fact that these are being charged from regulated customers. c) In order to rationalize charging of cross subsidy, we need Pakistani consumer mix to establish subsidizing consumers and highlight the ones which are being subsidized. FEL shared that its target customers are actually getting subsidies (cross subsidy + GoP subsidy). FEL can save approximately PKR 2 billion per annum in form of cross subsidy and GoP subsidy. FEL would further contribute towards DISCO revenue by paying approximately PKR 600 million as use of system charges for wheeled energy. d) It is prudent to highlight that if FEL wheels its energy, in addition to saving forex upto USD 30 million per annum on account of using indigenous fuel, it would help enhance production, exports and government revenue in the form of taxes and increase in employment. FEL plant when allowed to supply cheaper electricity to BPCs has capacity to help produce steel more than 1.5 million tons per annum or cement more than 8 million tons per annum, which can raise taxes to the tune of PKR 15 billion and providing more than 5,000 jobs. Furthermore, by successfully wheeling power to export industry FEL helped maintain employment opportunity to ~10,000 people as well as assisted in competitive cost for exports. It was suggested that aforementioned points shall be considered while making policy decision on cross subsidy as it is not justified to burden unrelated costs to Wheeler or BPCs. e) Cross-subsidies are economically not preferable and should be avoided – instead, a direct subsidy may be applied. If it is politically decided to apply a cross-subsidy surcharge at all, it should not exceed a certain amount especially for BPCs, industrial and commercial customers in order not to prevent competition and deprive the economy of its benefits. f) In order to have positive effect, target customers have to be adequately defined and the cost of supply need to be thoroughly calculated. This will also enable the estimation of funds really needed to support vulnerable customers.

	CENTRALIZED SECURITY CONSTRAINED ECONOMIC DISPATCH: 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. *(Ref: 4.2.2)* 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. *(Ref: 4.3.1)* 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. *(Ref: 4.3.1)* However, generation costs shall be disclosed to the System Operator for proper implementation of the Security Constrained Economic Dispatch. *(Ref: 5.4)* 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	a) Grid Code foresees central despatch mechanism under System Operator for technical stability of the system. b) As per Grid Code every participant is obligated to follow instructions of System Operator, in any emergent situation primarily on technical grounds. Grid Code also foresees PSODA for operation of such plants. c) Furthermore, must-run plants will be centrally despatched but are out of the economic merit order. Therefore application of economic dispatch mechanism to bilateral contracts will not be judiciously possible. d) This will also raise taxation issues on part of generation companies. e) Issue of recovery of start-up and partial load will also arise. f) Central dispatch is required for system stability however economic central dispatch shall not be mandated as it has many transparency, operation and financial implications. g) Considering the aforementioned multi-dimensional issues, economic central dispatch seems to be more of a theoretical and academic discussion which can only be implemented once electricity treated as pure commodity and traded on market without intervention of GoP machinery. Furthermore, there shall be certain sample size of open market Generating Companies to make a successful marginal pricing mechanism. Implementation of economic merit dispatch regime may be deferred for a suitable period till the time sizeable pool of open market Generating Companies is available.

	weather conditions (beyond the control of the generation company). *(Ref: 8.2)*	
	<u>HYBRID BPC:</u> 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. *(Ref: 5.2)*	a) There are number of industries which have generation on other sources like gas, RLNG, coal and/or RFO and draws electricity from DISCOs intermittently. One example is Textile (export based industries) which are provided gas at subsidized rate and generation of electricity is cheaper than DISCO rate. They only shift load to DISCOs when gas is not available and DISCOs supply electricity as per consumer requirement. b) Some industries, hardcore manufacturing, keep DISCOs as backup due to unreliable quality of electricity supplied. DISCOs supply them electricity as and when required. c) However, in all cases, these customers keep their connection active by paying applicable charges of DISCOs. d) Placing these conditions on BPC is against the principles of competitive market and a condition which would fail competitive regime at the onset. e) Marginal pricing regime as proposed by CPPA is more of academic value considering the current market dynamics whereby price is regulated and determined by NEPRA on case to case basis. If this concept has to be implemented then gradual steps shall be taken to liberate the market which may include implementation of bilateral contracts thru wheeling without intervention of NEPRA/CPPA. Subsequently freedom may be given to CPPA to independently determine marginal prices for transaction for certain period of time to establish transparency/confidence for smooth execution of market. Nevertheless it is too early to go directly to marginal pricing mechanism. f) Having supply from the incumbent utility / the grid as back-up is a common principle worldwide. It ensures that industrial customers can operate appropriately. Therefore, BPCs should be allowed to be hybrid customers and maintain a retail supply contract against payment of reasonable charges. Charging BPCs for availability of back-up supply should be non-discriminatory. Costs associated with the back-up supply are usually to some extent included in connection charges, monthly charges or even in the energy charge. BPCs therefore may already contribute to these back-up costs. When thus calculating retail and wheeling charges double payment shall be avoided.

	<u>MERIT ORDER CRITERIA:</u> 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. *(Ref: 16)*	Recently even the uniform formula for merit order approved by NEPRA for private operators has been rejected by CPPA and DISCO therefore the merit order which is prime criteria for economic central dispatch has become controversial and should not be implemented as proposed by CPPA.
	<u>CAPACITY OBLIGATION:</u> 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. *(Ref: Appendix-II 12)*	If the bilateral contracts scheme becomes financially unviable because BPCs are charged above their cost of service for wheeling and stand-by, the development of competition can be endangered in the longer term and export-oriented industries may become non-competitive.
	<u>MINIMUM PLANNING CAPACITY RESERVE:</u> **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%	a) If generating company is subjected to share the burden of losses of national network then the Consumers (in particular BPCs) will end up paying for aggregate losses of Discos when they may only use the system/networks of one or a few Discos for wheeling purposes. At best those BPCs should be required to pay only their share of the Use of System charges of the Discos whose networks they use – and not to pay for the losses of the inefficient Discos particularly when they impose no requirements on those Discos networks. b) Arrangement between generating company and BPCs is based on bilateral contract whereby generating company has to ensure committed supply to the BPC. Any reserve or shortfall in power generation may require the generating company to adjust or purchase power from alternate sources as needed to fulfil terms of bilateral agreements. c) CPPA's request means that the full cost of power generation, even for inefficient and high cost plants, is recovered from consumers. By contrast, low-cost suppliers such as captive plants pay for those inefficiencies through

	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: $APR = PD*(1+PL)*(1+RM) = 14.6 * 1.03 * 1.16 =$ **17.44 MW**	higher wheeling charges. This reflects unequal treatment of market participants. Specifically, the bulk power purchaser (CPPA in future, or NTDC/WAPDA for existing PPAs) could include all its costs in its Revenue Requirement, and those costs would be approved by NEPRA – if NEPRA approved CPPA's petition on Wheeling Charges. However, other producers (e.g. Captive Power Plants) not only have to compete with other producers/suppliers on their price of electricity – and cannot enhance their Revenue Requirement indefinitely, the petition also requires Captive Power Plants to compensate CPPA/WAPDA/NTDC for costs incurred by the latter. *d)* This issue is of complex nature and requires further deliberations with extensive studies to reach to a workable solution. For the time being it can be maintained as status quo as rightly pointed out in the CTBCM report; *"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." (Ref: 5.6.2)*

Energy That Moves Life

Mr. Iftikhar Ali Khan,
Director – Registrar Office,
NEPRA Tower, Attaturk Avenue (East),
Sector G-5/1,
Islamabad.

Ref No. KE/BPR/NEPRA/2020/446
April 29, 2020

SUBJECT: **DETAILED DESIGN REPORT AND IMPLEMENTATION ROADMAP OF COMPETITIVE TRADING BILATERAL CONTRACTS MARKET (CTBCM) MODEL SUBMITTED BY CPPA-G**

Dear Sir,

This is with reference to letter No. NEPRA/ADG(Lic)/LAN-100/7979-23 dated March 10, 2020, received in this office on March 13, 2020 on the captioned subject.

In this regard, please find KE's comments on the Detailed Design of Competitive Trading Bilateral Contracts Market (CTBCM) model submitted by CPPA-G, enclosed as **Annexure – A** to this letter. Please note that the delay in filing of comments is due to the prevailing COVID-19 pandemic which was also communicated to NEPRA vide our e-mail dated March 25, 2020 and extension in this regard was allowed by NEPRA through e-mail dated April 24, 2020.

Further, considering the material implications of the CTBCM model on consumers and the sector at large, we request NEPRA to hold stakeholder consultative session and also provide an opportunity of hearing to ensure that interest of all stakeholders is balanced, thus enabling a smooth transition.

Sincerely,

Ayaz Jaffar Ahmed
Director – Finance & Regulations

Encl: Annexure – A

Cc: Registrar, NEPRA, Islamabad.

Annexure A

Comments on Detailed Design of CTBCM Model

NEPRA through its determination dated December 05, 2019 approved the high-level design of Competitive Trading Bilateral Contracts Market (CTBCM) Model and subsequently, CPPA-G submitted detailed design of the model.

The CTBCM model is a major change to Pakistan's power sector landscape and we appreciate the efforts of CPPA-G in this regard. However, to ensure a sustainable transition, it is important to take into account the possible implications for regulated consumers at the cost of a select group of high-end consumers and power sector entities along with legal, commercial and regulatory intricacies of the sector in its existing form.

Here, we would like to submit that filing of comments in respect of the subject matter is without prejudice to KE's exclusive rights of distribution in its service territory till 2023 as granted through KE's Distribution License dated July 21, 2003 and pending Constitutional Petition No. 8623/2018. Therefore, these comments are being filed, to place on record / apprise about KE's viewpoint in the instant subject for NEPRA's consideration, so as to ensure a sustainable transition of CPPA-G's market towards the proposed regime, with a view to ensure reliable and uninterrupted supply of power to all consumers at least possible cost, while balancing the interest of all stakeholders.

A. Evaluation of a Suitable Model for Pakistan's Power Sector

Given the various challenges that have put the operational and financial sustainability of the power sector at risk, it is imperative that a detailed and informed analysis drawing upon best international practices and recognizing the peculiarity of the local power sector is undertaken along with effective stakeholder consultation, prior to implementation of the proposed CTBCM model.

i. Key Power Sector Issues Unaddressed under the CTBCM Model

With surplus power capacity available in the country today, the model does not seek to address critical issues faced by Pakistan's power sector, including soaring levels of circular debt which has reached an alarming level of c. PKR 1.6 Trillion, lack of private participation in the T&D segment, lack of investment in T&D infrastructure, demand side management, governance issues in state-owned entities, and high Aggregate Technical & Commercial (AT&C) losses. Instead by offering incentives for generation business, the model seeks to aggravate the issue of capacity under-utilization by enabling addition of private generation projects for consumers who opt out of DISCOs.

It is imperative that a framework for resolving pressing issues of the power sector today is agreed and targeted regulatory/governance interventions are done to ensure that objectives of reliable supply of electricity at least possible cost for all consumers is achieved. It is therefore important that the National Energy Policy and National Electricity Plan are deliberated and formalized first and then the required interventions are made.

ii. Incentives for Generation Business at the Cost of T&D Business

The CTBCM model in its current form is skewed towards incentivizing generation business by allowing GENCOs / IPPs to sell power directly to Bulk Power Consumers (BPC) and majority of the risk is still parked with Distribution Companies (DISCOs) responsible for supply of power to the regulated consumers along with having to bear the risk of T&D losses in case where they are higher than NEPRA set benchmarks as well as deal with recovery issues since they will be disconnecting on the instructions of competitive suppliers / traders, while contribution margin of DISCOs would be reduced to wheeling charges only. In addition, the CTBCM model allows the same generator to charge different rates for BPCs and DISCOs (suppliers of last resort), which may result in price discrimination, thus allowing the generator to charge lower prices to blue-chip customers, at the cost of regulated customers of supplier of last resort.

iii. Stranded Costs

The CTBCM model does not adequately cover the long-term capacity commitments already entered into by the government on behalf of DISCOs, which may further exacerbate by allowing generators and competitive suppliers / traders to cherry pick good consumers of DISCOs, thus exposing DISCOs to the risk of idle capacity payments and stranded costs, which would only add to the issue of circular debt. In this regard, as per NTDC's Indicative Generation Capacity Expansion Plan 2047 (IGCEP), under the normal growth scenario and considering the committed projects only, there is a projected surplus of around 13,000 MW (excluding renewables) in 2025 against the nominal / despatchable capacity, which could further increase as a result of growth in distributed generation and regulations / policies incentivizing high-end consumers to go off-grid. Accordingly, with incentives for BPCs to procure power directly from the market, this would result in stranded costs as DISCOs would continue to incur certain fixed costs, including capacity charges, which would ultimately have to be borne by DISCOs, or the remaining regulated consumers resulting in increase in tariff for regulated consumers, or the Government of Pakistan (GoP) in the form of Tariff Differential Claims (TDC).

iv. Increase in T&D Losses

Under the CTBCM model, BPCs having load greater than 1 MW are allowed to participate in the open market and procure power directly from the market. The existing tariff regime in Pakistan is based on a cost-plus mechanism, wherein the allowed cost component includes T&D losses. Allowing BPCs to procure directly from the market would result in loss of high tariff consumers (mainly industrial), leaving DISCOs with low-paying consumers and high loss areas, thus increasing T&D losses and ultimately the cost of service.

The expected increase in T&D losses driven by BPCs procuring power directly from the market would not be an exception in context of the local power sector. As observed in case of Turkey, despite introduction of competition, the state-owned enterprises continued to incur high system losses[1]. Eventually, EMRA (Turkey's regulatory body) allowed this increase and raised the T&D loss targets[2]. Therefore, assuming a similar trend in Pakistan, NEPRA would have to compensate and adjust the T&D loss benchmarks allowed in DISCOs' tariff, which inadvertently would result in increased cost for regulated consumers or have to be borne by the GoP in the form of TDC, thus further increasing the circular debt.

Importantly, most of these concerns were raised by KE through its previous submissions on the subject matter including at the time of high-level design of the proposed CTBCM model. In response to KE's concerns, CPPA-G submitted that the proposed model is prepared for the design and implementation of the Wholesale Electricity Market (WEM) rather than reforming the powers sector. CPPA-G further submitted that the proposed model has been prepared after studying different models and implementation of this model will enable risk sharing among market participants and may help alleviate challenges faced by the power sector. However, no deliberation validating how the proposed model is suitable considering the current challenges of the power sector has been done by CPPA-G or NEPRA. Accordingly, it is important that detailed analysis on the effectiveness of the CTBCM model in context of the local power sector is undertaken and shared with stakeholders.

Considering the above challenges / issues, it is strongly recommended that prior to implementation of the model, reforms be introduced in the T&D segment along with measures to improve governance and required investments in the T&D segment, which would thereafter bring operational efficiency / improvements in DISCOs. Further, going forward, it is recommended that cost of service study should be done to identify and account for necessary

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[1] The World Bank (2015). *Turkey's Energy Transition: Milestones and Challenges* Report. (Report No. ACS14951). Retrieved from: http://documents.worldbank.org/curated/en/249831468189270397/pdf/ACS14951-REVISED-Box393232B-PUBLIC-EnergyVeryFinalEN.pdf

[2] Nezvat Onat, "Electricity Theft Problem and Effects of Privatization Policies on Distribution Losses of Turkey". Celal Bayar University Journal of Science, Volume 14, Issue No. 2 (2018): 163-176. Retrieved from: http://static.dergipark.org.tr/article-download/a284/93b2/4ae0/5b35495c50ccf.pdf?

costs to ensure full recovery of costs incurred by DISCOs, which otherwise would materially impact the financial sustainability of DISCOs and the sector at large.

Moreover, with continuous addition on the generation side, particularly renewables, to ensure security of supply along with sustainability of the sector and keeping in view the fact that their capacity limits that how much renewable power can be integrated with the grid, it is important that new renewable projects are committed by DISCOs for their consumer base, instead of allowing renewable projects to serve the interest of few consumers only.

B. Comments on the Detailed Design of CTBCM Model

Considering the material implications that the proposed model may have on consumers and power sector entities, in addition to focused sectoral reforms to overcome the existing challenges of the sector prior to implementation of the CTBCM model, following issues / comments must be taken into consideration by NEPRA, to ensure that interest of all stakeholders is balanced, thus enabling a smooth transition of CPPA-G's market towards the proposed regime.

i. Cross-Subsidization

Under the GoP's existing policy for tariff structure, high-end consumers including BPCs cross-subsidize the low-end consumers. By allowing BPCs to procure power directly from the market, BPCs will be able to avoid cross-subsidy payments. This not only defeats the cross-subsidization policy of the Government, but also impairs the competitive landscape for DISCOs, which would be obligated to supply power to regulated consumers, and whose tariff Terms and Conditions will be determined by NEPRA and accordingly, DISCOs cannot commercially set their tariff to compete. This will eventually have to be either taken up by the GoP or the regulated consumers or borne by DISCOs. Accordingly, before opening up of the markets, it is important to assess how these costs associated with GoP's social objectives will be allocated.

Assessing the Indian market, when markets were open, recognizing the issue of cross-subsidy and its material implications on DISCOs and regulated consumers, a cross-subsidy surcharge was included in addition to wheeling and network charges. Accordingly, prior to implementation of the model, it is imperative that these social and policy costs are fully accounted for, such that the interest of all stakeholders is balanced, which otherwise could seriously jeopardize the sustainability of DISCOs and have an adverse impact on the regulated consumers.

Further, it is suggested that a cost of service study should be done to identify and account for necessary costs to ensure their full recovery by the Transmission Licensees or DISCOs.

ii. Tariff Differential Claims & DISCOs' Reliance on Government

Under the existing set up, TDC to be paid to DISCOs by the GoP are netted off against the cost of power purchased from the CPPA-G/NTDC. However, the competitive market envisages bilateral contracts between DISCOs and GENCO/IPPs, which will require direct payments by DISCOs to GENCOs / IPPs. Given that subsidy receivables in respect of regulated consumers may continue to pile up along with additional costs for DISCOs in the form of credit cover required under the CTBCM model, this will have serious implications on liquidity of DISCOs and their ability to make direct payments to GENCOs / IPPs, ultimately putting the market and sector sustainability at risk.

Here, it is pertinent to mention that as state-owned distribution companies would continue to remain under government control, their obligations would eventually have to be taken up by the GoP, thus could potentially add to the issue of circular debt.

As a result, prior to implementation of the model, mechanism for clearance of outstanding subsidy receivables of DISCOs should be formulated. Further, focus should be on restructuring/ privatizing the state-owned distribution companies to mitigate DISCOs' reliance on GoP and to make them financially self-sufficient.

iii. Lack of Certainty for Lenders due to shift from 'Take or Pay' Mechanism, Future Capacity Commitments by DISCOs & Fuel Supply Commitments

Under the existing model, there is no clarity on how security shall be provided to financers of debt / lenders, particularly for large size projects, in the absence of guaranteed off-take. Further, as BPCs will be allowed to procure directly from the market, there is no clarity on how long-term commitments will be made by DISCOs considering the uncertainty regarding BPCs, as the same may have significant implications for demand-side planning.

Moreover, considering that IPPs have contracts on 'Take or Pay' basis with fuel suppliers, accordingly, the model needs to provide clarity on how removing 'Take or Pay' will be accounted for in case of these supply contracts, whilst ensuring security of fuel supply in the future.

iv. Execution of Bilateral Contracts by DISCOs

The CTBCM model envisages procurement of capacity by Independent Auction Administrator (IAA) on behalf of DISCOs and that DISCOs would enter into bilateral contracts. Given the current financial standing of DISCOs and the requirement of credit cover to enter into bilateral contracts, their privatization should be considered prior to opening up of the market, which otherwise would continue to rely on government support (GoP being the ultimate owner of state-owned distribution companies), and the same may defeat the overall purpose of the CTBCM.

Accordingly, it is suggested that privatization of state-owned distribution companies should be undertaken, and when privatized, they may be required to retain the existing supply quota for certain number of years (e.g. 5 years) so that they can then make their own plans for future procurement of power.

v. Additional Costs including Credit Cover & Taxes

The CTBCM model requires credit covers both for bilateral transaction as well as participation in the centrally administered markets by the Market Operator (Balancing Mechanism), with assistance from IAA in case of weak performing DISCOs which would involve a guarantee support scheme from the GoP to facilitate these DISCOs for their participation in the CTCBM. This will have two implications; (i) DISCOs would have to bear additional costs which will then have to be allowed in their tariff for regulated consumers, as owing to delays or non-release of TDC from the GoP, DISCOs already have to bear the cost of additional working capital, and (ii) given that majority of the DISCOs are in losses, they may not be able to raise credit cover on their own financial standing, which would result in continued involvement / dependence on the GoP, ultimately defeating one of the key objectives of CTBCM which is to reduce government dependence.

In addition to cost of credit cover, the settlement of imbalances through marginal pricing as suggested by CTBCM model will have tax implications such that there are different taxes for electricity generated and sold, and electricity purchased and sold (trading).

Currently, there is no discussion/deliberation on taxes/duties which may increase as a result of more parties within the value chain, eventually resulting in increased cost to be passed on to the regulated consumers. It is therefore important to provide necessary clarification on taxation along with a mechanism such that the interest of all stakeholders is balanced.

vi. Possible Arbitrage Opportunities

The main objective of the centralized economic despatch as envisaged under this model is to ensure least cost generation in the entire system. However, as also recognized by CPPA-G in its detailed design, there are possible arbitrage opportunities for the retiring plants who have recovered their fixed costs and have very low efficiency, as these plants can enter into bilateral contracts and later procure power from the market at lower marginal prices, thus resulting in arbitrage gains.

Although the model recognizes the possibility of such arbitrage opportunities, however, no mechanism is provided to eliminate the same. Accordingly, the market model must address this issue and NEPRA, as a regulator should also take into account the possibility of market distortion through arbitrage opportunities as a consequence of CTBCM model. Therefore, to ensure that no such market exploitation takes place, NEPRA must enforce strict regulatory checks with disclosure requirements for power generation and purchase costs of such suppliers to check against any abnormal profits.

vii. Risk-free and Higher Margins for Generators

The CTBCM model in its current form allows for opportunistic use by the Generators. As an example, assuming a bilateral contract is executed between Generator X and Buyer Y at an agreed price of P_x. Subsequently, if the energy price of Generator X (P_x) is higher than the marginal price or the clearing price of the market (P_m), Generator X will not be despatched and the demand requirement of Buyer Y will be met through the market, at the market clearing price of P_m, while Generator X will receive the rate bilaterally agreed between the parties, which is P_x. As a result, Generator X will make a higher margin ($P_x - P_m$), without having to take any additional risk.

The CTBCM model does not provide any check or monitoring against such practices, which could unarguably compromise the sustainability of the market and sector at large. Accordingly, NEPRA as well as the policy makers must take the same into consideration to safeguard any possible market exploitation.

viii. Risk of Possible Tacit Collusion

Under the existing tariff framework, NEPRA allows variation in cost of power purchased from IPPs to be passed through to consumers. We understand that the market structure under CTBCM similarly proposes that the cost be passed through to the consumers in case when DISCOs purchase directly from GENCO/IPPs in an open market in the absence of a bilateral contract / PPA. However, the model does not specify any controls in place to ensure that generators and suppliers would not possibly collude, which would otherwise lead to increase in power purchase cost for consumers.

Tacit collusion in open electricity markets has precedents even in developed markets, such as California, UK, Spain, where generators / suppliers have managed to get away with collusion for years after deregulation. Such collusion was also observed in Germany where energy giants; E.ON, RWE, EnBW and Vattenfall (c. 80% share of the total electricity market) operated like a cartel for years; led by E.On which 'substantially influenced' electricity prices, hence defeating the very purpose of bringing competition through open electricity markets[3].

Accordingly, a mechanism must be put in place by CPPA-G which defines a ruling price or price cap which all the eligible participants need to follow along with strict regulatory checks.

ix. Price Volatility Risk

Further to additional costs through taxation, credit cover, etc. market participants will also be exposed to the risk of price volatility due to option of selling in spot market and removal of caps on tariff. This is due to the fact that predictability of prices in the market is not fully achieved because of uncertainties in production costs, any unexpected failure, sudden drop in demand etc. Further, local markets would take considerable time before introduction of instruments to hedge this risk, and therefore till such time, market participants would be exposed to price volatility risk.

[3] DW Staff, "Report: German Energy Firms Colluded to Manipulate Markets", DW, November 05, 2007. https://www.dw.com/en/report-german-energy-firms-colluded-to-manipulate-markets/a-2871019

With regard to price volatility in open electricity market, in summer of 2000, in California, prices increased from $30-35/MWh to as much as $750/MWh, and even in winter with low demand due to seasonal impact, because of issues such as unanticipated outages, transmission congestion and possible exploitation of the regulatory mechanism, the prices remained in the range of $260 to $400/MWh, having severe adverse implications for distribution companies as well as consumers, eventually leading to state intervention[4].

Accordingly, to mitigate any price fluctuations, which otherwise can eventually have adverse implications for the market, a mechanism may be devised in consultation with stakeholders.

x. Capacity of Renewable Power Plants

Within the detailed design, it has been proposed that a firm capacity factor will be applied to renewable power plants, thus allowing them to enter into bilateral contracts. In this regard, as submitted in the detailed design, we understand that details of methodologies adopted for calculating firm capacities of renewables have been shared in IE-MSM report, which is currently awaiting NEPRA's approval. Accordingly, we request that the same should also be shared with stakeholders for deliberation and consultation.

Further, as per the model, firm capacity for renewables is proposed to be allowed based on 'most loaded hours' which works on the contribution of each type of technology to the security of the system during the most loaded hours. However, considering the intermittent nature of renewables and their varying generation profiles, which may even differ on the basis of plant location (e.g. plant in south may have a different profile as compared to a plant in north), firm capacity based on application of the same factor for similar renewable plants is not viable.

Here, it is also important to note that due to the intermittent nature of renewable plants, this would require greater flexibility on the part of other generators in the system, which is likely to result in increased wear and tear on conventional generators, thus resulting in higher O&M costs along with the need to schedule more frequent maintenance outages.

Since the model obligates suppliers to ensure that they have enough contracted capacity, considering the intermittent nature of renewables, there should be a cap on the maximum share of renewable capacity out of the total capacity contracted, to avoid any sudden imbalances.

xi. Capacity Pricing in Balancing Mechanism

Under the existing form, capacity price, which will be used in the Capacity Balancing Mechanism will be the intersection of the demand and supply curves, thus possibly resulting in exponential returns for generators having capacity price below the intersection point establishing the capacity price. Further, it is to be noted that determination of capacity price through demand-supply intersection during critical hours would also include renewables which have an intermittent nature associated to them, thus resulting in conventional plants to remain available to meet the overall demand, for which in some cases minimum fuel inventory levels may also be required.

Accordingly, it is recommended that instead of the capacity pricing based on demand-supply intersection, every generator should receive the capacity price it bids in the market.

xii. Capacity of Competitive Suppliers

The model in its existing form does not include any criteria for entry of a competitive supplier, which is critical to ensure sustainability of the sector. In this regard, learnings from the UK market can be drawn upon where in an attempt to encourage competition, 'Supplier in a Box' (SIAB) model was introduced to

[4] Vladlena Sabodash, John Kwoka (2009). *Price Spikes in Electricity Markets: "Business by Usual Methods" or Strategic Withholding?* Presentation for the 7th Annual International Organization Conference, Northeastern University.
Retrieved from: https://editorialexpress.com/cgi-bin/conference/download.cgi?db_name=IIOC2009&paper_id=384

ease out entry barriers in the market. However, as a fallout, in 2018, 30% of suppliers entered through SIAB in the UK market failed due to inadequate checks on entry of suppliers to boost competition in the market[5]. In case, where these suppliers are not able to meet their obligations, eventually the burden will have to be passed on to DISCOs (suppliers of last resort) which could have material commercial and financial implications, while also putting the sustainability of the sector at risk.

Further, under the NEPRA Act and also envisaged in the CTBCM model, disconnection of power supply upon payment default is to be made by network business (DISCOs), which would ultimately involve additional cost for DISCOs and the same may not be adequately compensated through wheeling charges.

It is therefore important that regulations include well defined criteria, developed in consultation with stakeholders, for grant of license to competitive suppliers.

xiii. Credit Risk

Under the existing framework, the only criterion applied to eligible consumers is load greater than 1MW. However, to ensure timely payments to generators or competitive suppliers/traders and ensure sustainability, a minimum credit worthiness criterion should be set, including the capacity of BPCs to be able to correctly forecast their demand requirement and become a market participant.

xiv. GoP Support for Nuclear / Hydel Projects

As per NTDC's IGCEP, over 11,000 MW of nuclear and hydel projects have already been committed till 2030. Due to their size and strategic significance, these projects are built in support from the GoP, however, the model does not clarify whether the government will continue to play its role in hydel and nuclear projects. Accordingly, the CTBCM model must clearly articulate as to how hydel and nuclear plants will be dealt in this plan as the same are built with support of the GoP.

Summary

A summary of issues within the existing CTBCM model along with their possible implications and proposed recommendations is given below:

Issues	Possible Implications	Proposed Recommendations
Cross-Subsidization	• Existing tariff regime in Pakistan includes cross-subsidization – high-end consumers cross-subsidize low-end consumers • Non-inclusion of cross-subsidy surcharge may seriously jeopardize the sustainability of DISCOs and have an adverse impact on the regulated consumers	• Inclusion of cross subsidy surcharge for consumers opting for open markets as also done in India • Change in existing tariff regime and move towards cost of service model with gradual elimination of cross-subsidization
Tariff Differential Claims & DISCOs' Reliance on Government	• Further accumulation of subsidy could exacerbate liquidity issues of DISCOs • Being GoP owned, state-owned DISCOs would continue to rely on GoP support	• Mechanism to clear outstanding subsidy receivables of DISCOs prior to implementation of the CTBCM model • Privatization of state-owned DISCOs which would result in operational improvements along with making DISCOs financially self-sufficient

[5] Rahmatallah Poudineh, "Liberalized retail electricity markets: What we have learned after two decades of experience?". The Oxford University for Energy Studies, 2019. Retrieved from: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/12/Liberalized-retail-electricity-markets-EL-38.pdf

Issues	Possible Implications	Proposed Recommendations
Lack of certainty for lenders due to shift from 'Take or Pay' Mechanism, Future Capacity Commitments by DISCOs & Fuel Supply Commitments	• Uncertainty for lenders / financers in the absence of guaranteed off-take • Uncertainty regarding BPCs could have material implications for DISCOs in terms of demand planning and future capacity commitments • No clarity on already executed fuel contracts on 'Take or Pay' basis which may impact future fuel supply	• Market model should recognize and devise a mechanism in consultation with all stakeholders, including policy makers to ensure long-term security of supply
Execution of Bilateral Contracts by DISCOs	• Existing governance and structural issues within DISCOs impact their ability to participate in the market, which could also potentially put the sustainability of the sector at risk	• Privatization of DISCOs to make them financially self-sufficient prior to implementation of the CTBCM model
Additional Costs including Credit Cover & Taxes	• Requirement for credit cover to participate in balancing mechanism would result in additional burden on DISCOs • Government dependence to continue in case of weak DISCOs as they may not be able to arrange credit cover on their own • Increased cost and complexities due to taxation as a result of more participants in the value chain	• Privatization of DISCOs to make them financially self-sufficient • Provide necessary clarification on taxation along with a mechanism such that the interest of all stakeholders is balanced
Possible Arbitrage Opportunities	• Retiring plants having recovered their fixed costs and very low efficiency may enter into bilateral contracts and later procure power from market at lower marginal prices	• Market model must address this issue and NEPRA should also take into account the possibility of market distortion through arbitrage opportunities
Risk-free and Higher Margins for Generators	• Opportunistic use by Generators to earn higher margins (bilaterally agreed price being higher than the market clearing price) without taking any additional risk	• NEPRA and policy makers should devise a mechanism to avoid any such market exploitation
Risk of Possible Tacit Collusion	• Increased cost due to possible tacit collusion of generators and suppliers to charge higher prices and gain a larger market share	• A mechanism by CPPA-G defining a ruling price or price cap which all the eligible participants need to follow • Strict regulatory checks and monitoring
Price Volatility Risk	• Financial losses for market participants and adverse implications for consumers	• Mechanism to protect market participants from price volatility e.g. introduction of price caps
Capacity of Renewable Power Plants	• Intermittent in nature • Varying generation profiles due to various external factors, including geographical location can have adverse implications from planning perspective • Requirement of greater flexibility of conventional generators – resulting in greater wear and tear of conventional generators and thus higher O&M costs	• Cannot be considered as part of base load supply • A maximum cap should be placed on renewable capacity out of the total contracted capacity to avoid sudden imbalances

Annexure A

Issues	Possible Implications	Proposed Recommendations
Capacity Pricing in Balancing Mechanism	• Possibility of exponential returns for generators having capacity price below the intersection point establishing the capacity price	• Each generator should receive the capacity price it bids in the market
Capacity of Competitive Suppliers	• Failure of competitive suppliers to fulfill their obligations would transfer the burden on to DISCOs as supplier of last resort	• Regulations to include well defined criteria, in consultation with stakeholders, for grant of license to competitive suppliers
Credit Risk	• No criteria to ascertain the credit worthiness of BPCs participating in the market – increases the credit risk and may have adverse implications for sector sustainability, including planning issues	• In addition to requirement of 1MW, a minimum credit worthiness criteria should be included for BPCs for them to be eligible to participate in the market
GoP Support for Nuclear / Hydel Projects	• Critical to ensure security of supply and generation mix	• Model must include how hydel and nuclear projects will be dealt with under CTBCM, as the same are built with GoP's support

In addition to the comments provided herein, KE further requests NEPRA to allow submission of additional comments as well as an opportunity of hearing for further discussions and deliberations in the instant matter.

No.42 (10)/EF&E/PD&SI/2020
Government of Pakistan
Ministry of Planning, Development & Special Initiative
Energy Wing
****

No.42 (10)/EF&E/PD&SI/2020 Islamabad the 5th May, 2020

Subject: **Detailed Design Report and Implementation Roadmap of Competitive Trading Bilateral Contract Market (CTBCM) Submitted by CPPA-G**

Please refer NEPRA letter No. NEPRA/ADG(Lic)/LAN-100/7979-23 of dated March 10, 2020 on the above subject.

2. The comments of Planning Commission, Ministry of Planning, Development & Special Initiative on the subject are enclosed.

(Aftab Ahmad Awan)
Deputy Chief
051-9220620

Mr. Iftikhar Ali Khan,
Director, NEPRA,
Islamabad

For information & n/a pl.
ADG (Lic)
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8/5/20

cc. Chairman
- VC/M (M&E)
- M (T)
- M (CA)
- M (Lic)

COMMENTS ON DETAILED DESIGNED REPORT AND IMPLEMENTATION ROADMAP FOR COMPETITIVE TRADING BILATERAL CONTRACT MARKET

Capacity obligations:

- It is proposed in the report that capacity obligations are a very important feature of CTBCM. It is observed that historically capacity obligations have been the root cause of higher tariff and circular debt issue in our power sector. It is suggested to look for alternative arrangements and future contracts (PPAs) should be on the take and pay/on an auction basis.

- Firm capacity certificates would be provided to generators. It is not informed who would issue these certificates and what would be the duration of these certificates. Network services providers both transmission and distribution to ensure network up-gradation under capacity obligations, otherwise, severe penalties would be imposed. Presently NTDC is sufficiently investing to expand its network and can obtain financing from the market on the basis of its balance sheet. However, DISCO's particularly those with the weak financial position and having adverse consumer mix that is up to 80% or so domestic consumers. Secondly, under CTBCM bulk consumers would come in the market that means a further weakening of DISCOs consumer base. Under this scenario, how would DISCOs invest in system up-gradation?

- Load following generation plants to be rewarded. This means special/separate tariffs for those plants. Tariff methodology for this may be developed before the commencement of the market.

Balancing:

- DISCOs with adverse consumer mix and also having low recovery will always remain in positive imbalance, reason being that they had contracted capacity and energy keeping in view their and load based on total consumers and annual growth. However, they carry out forced outages/load shedding on low recovery feeders. Thus, they would not be able to utilize their full contracted capacity and energy.

- Allocation criteria in a market environment where bulk consumers would be allowed to make contracts with generators, the DISCOs would be left with domestic consumers. Thus, their load factor would be low which would adversely the effect their payment capacity.

- Under economic dispatch, inefficient plants must not be despatched. The criteria may not only be least-cost generation as it favours the inefficient plants of GENCO's. These plants have efficiency as low as 23% and still are dispatched as they are run on cheap domestic gas. Whereas high-efficiency plants having an efficiency of above 55% are not dispatched because of expensive imported LNG. Similarly, there have been curtailments on wind generation due to lower demand.

- Settlement proposed payment is on a weekly basis whereas end consumers pay on a monthly basis how it would be maintained. The monthly statement also includes any previous adjustment resulting from resolving complaints and dispute. However, timeline for resolving the dispute is not mentioned which is essential, otherwise, riders would pile up and create another circular debt like situation.

Sovereign guarantees:

- Weak DISCOs and new suppliers with weak financial position would get funds on higher rates which in turn would be reflected in high consumer end tariff.
- The weak financial position of DISCOs forces the government to intervene so as to maintain the average price all over the country. In 0rder to end this DISCOs has to improve performance for which timeframe has to be fixed which should not be later than the commencement of Market. This is going to be the challenge as over-the-years their performance is not improving.

A review of the detailed design of the Competitive Trading Bilateral Contract Market (CTBCM)

ALI ZAIN BANATWALA

Consultant to Planning Commission (Energy Wing)

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1. CTBCM design in the context of centralized and decentralized markets

The primary task in bulk electricity generation and transmission is physical control of the system.

The ultimate authority for physical control is assigned to a system operator (SO) that is responsible for managing the transmission system. Control has three components – energy, transmission and reserves. Each component has an important time dimension that differentiates between forward planning and real-time operations.

While the SO has sole authority in real-time operations, different market designs assign different degrees of authority over forward planning.

In highly centralized systems, the SO optimizes the allocation of generation and transmission, whereas in decentralized systems the allocation is done by markets for energy and transmission.

The forward markets for energy and transmission are best interpreted as financial markets. The purely financial aspect is especially strong in the case of bilateral contracts, since often these are structured as "contracts for differences" in which the parties insure each other against differences between the real-time price and their agreed-on price, and physical differences are settled at the real-time price.

Decentralized markets

Bilateral contracts and balancing mechanisms are features of *decentralized* markets. The arrangements for trading electricity in Great Britain, known as the British Electricity Trading and Transmission Arrangements (BETTA), feature a forward bilateral market and a Balancing Mechanism (for energy). One of the main purposes of the Balancing Mechanism is to deal with transmission congestion.

> Market participants in BETTA perform bilateral electricity trades in the forward markets. Such trades are continued until "gate closure", which is the time boundary between forward planning and real-time operations. Gate Closure (GC) is typically set at one hour before the relevant delivery period. At GC, the forward bilateral market stops; contract positions of the participants submitted to the SO constitute the "Final Physical Notification" or FPN. During the remaining hour, i.e. during real-time operations, the SO runs the Balancing Mechanism in which it accepts offers and bids of generators to increase or to decrease output, acting as a sole counterparty to these trades.

Centralized markets

Power pools on the other hand are examples of *centralized* markets. Pools describe a system in which participation is mandatory and the "market" includes substantial intervention into unit commitment and scheduling. Pools fully integrate energy, transmission and reserve markets by way of a centralized optimization of unit schedules. Pools are typically carried over from the operational procedures of vertically integrated utilities that entirely managed their own generation and transmission systems to serve their native loads, for which they had regulated monopolies.

Competitive Trading Bilateral Contract Market (CTBCM)

The CTBCM detailed design document states in section 1.1 (page 9) that "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." As such on page 19 it is stated that the CTBCM is "designed as a bilateral contract market with balancing mechanisms."

However, page 43 states that "the Generators will be dispatched by System Operator as per procedures defined in the Grid Code for Security Constrained Economic Dispatch (SCED)." Furthermore, section 8.2 (page 41) states "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."

Therefore, one may conclude that the proposed CTBCM design can be categorized as a centralized market with elements of decentralized markets.

2. Assessment of CTBCM's main organizational features

3.1. Scheduling and settlement of energy volumes

Centralized scheduling is appropriate considering the large volume of existing PPAs that need to be grandfathered into the competitive wholesale market. These PPAs would be assigned *Generation-following* contracts, where the imbalance risk will be fully borne by the DISCOs. As stated in section 8.3 (page 41), "the design of the existing PPAs in Pakistan (pre-CTBCM) can be assimilated to this type of market contract design." As these power plants are currently already being centrally scheduled (by NPCC[1]), the new market design will have a minimal impact on existing PPAs from an energy scheduling and settlement perspective.

An important caveat is that in order to obtain an accurate result from a SCED algorithm, generator cost curves (also known as heat-rate curves) are required. However, none of the PPAs signed prior to the 2015 Power Policy required the IPPs to submit their heat-rate curves. This means that unless the remaining power plants are required to submit accurate heat-rate curves, the SCED will operate on the heat-rate curves of only nine power plants

Furthermore, dynamic models of power plant controllers such as Automatic Voltage Regulators (AVR) and turbine governors which are a requisite for ancillary services such as automatic generation control (AGC) for load-frequency control (LFC) are also required by the SO.

Section 16 (page 89) of the detailed design states that "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 SCED algorithm requires accurate heat-rate (cost) curves for accurate scheduling. If heat-rate curves from only nine power plants (signed under the 2015 Power Policy) are available, the SCED results will not be accurate. This risks a sub-optimal dispatch and higher costs for consumers.**

[1] National Power Control Centre (NPCC) is the current System Operator

- **Detailed SOPs are required to perform not just the verification process of heat-rate curves, but also verification of dynamic models of power plant controllers that are required for programming automatic control signals such as AGC for provision of real-time system control and stability.**

3.2. Cost recovery of merchant (non-PPA) generators

Cost recovery of legacy PPA contracts is not a problem as fuel costs for those power plants are passed through to consumers.

On the other hand, the proposed design for energy scheduling and settlement may not enable full cost recovery for merchant power plants that contract with competitive suppliers or bulk power consumers.

Bilateral contracts signed by merchant power plants will most likely be of the *load-following*[2] type (where the imbalance risk is assigned to the generator) or the *financial*[3] type (where the imbalance risk is shared between the counterparties).

However, market participants are not allowed to self-schedule and the generator's physical schedule would be determined by the SO (in the SCED run). Therefore, the resulting imbalance (between the contract schedule and the physical schedule) would be settled by the Market Operator (MO) at the System Marginal Price (SMP).

The reason why full cost recovery may not be possible is that the SCED algorithm only takes into account the incremental energy cost (USD/MWh), whereas there are as two additional components in a generator's offer to sell energy, i.e. the start-up cost (USD/start), incremental energy cost and the no-load cost (USD/h). Furthermore, by not operating at optimal schedule (which would have been the case had the generator been self-scheduled), the generator is not maximizing its profit potential.

Therefore, in US ISO/RTO markets such as PJM, generators with SCED-determined schedules receive uplift payments[4] with two components – "make-whole payments" that include fixed costs (i.e. start-up and no-load costs) that occur when a resource's revenue cannot cover its total offer costs, and "lost opportunity costs" that occur when a resource's dispatch set-point is not profit maximizing.

As per the CTBCM design, bilateral contracts will be settled at the contract price, whereas imbalances between the contracted schedule and the SO-determined schedule will be settled by the MO at the System Marginal Price (SMP). Therefore, a generator with a lower marginal cost than the SMP would theoretically recover at least it's variable (fuel) cost.

However, if the low-cost generator is constrained-off due to transmission congestion, the generator would have to purchase some or all of the volume sold bilaterally back at the SMP, which would be higher if the aforementioned generator is not the marginal cost generator. In this case, the generator will make a loss. A worked example is provided in Appendix A.

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[2] CTBCM detailed design document, section 8.4, page 47

[3] ibid. section 8.6, page 50

[4] https://www.pjm.com/-/media/committees-groups/task-forces/epfstf/20180129/20180129-item-07b-lmp-calculation-and-uplift.ashx#page=25&zoom=auto,-84,538

CTBCM contains no uplift mechanism for "make-whole payments" or "lost opportunity costs" which are needed for cost recovery when power plants are not self-scheduled. Furthermore, there is no mechanism to compensate constrained-off generators for the potential loss incurred by having to purchase energy at a higher SMP than the bilateral contract price.

- **Inclusion of uplift payments to merchant power plants for "make-whole payments" and "lost opportunity costs" should be considered.**

3.3. Pricing and allocation of transmission losses and congestion costs

In a restructured power system, the transmission network is where generators compete to supply bulk power consumers and distribution companies. Thus, transmission pricing should be a reasonable economic indicator used by the market to make decisions on resource allocation, network expansion and system reinforcement.

It is important to note that transmission pricing refers to both operational costs and fixed costs such as recovery of capital investment (or embedded transmission costs). Fixed costs are much larger than operational costs and generally not considered relevant in market design. As such the pricing and cost recovery methodology for fixed costs are not addressed in this document.

Crucially, the pricing scheme and cost recovery for transmission capacity allocation in any market structure should be fair and practical. In this regard, there are two questions that are applicable –

1. What is the pricing mechanism for operating costs such as losses and congestion?

   The most common and simplest approach to transmission pricing is the "postage-stamp" method based on average system costs. This is the methodology currently employed in Pakistan. One limitation of this approach is that when energy is transmitted across several utility systems, it can suffer from a "pancaking problem". Other commonly used methods include the contract path method and the MW-km[5] method which is a flow-based pricing scheme. The main drawback of these approaches is that they do not consider transmission congestion.

   The fairest way to allocate transmission congestion costs and losses is with nodal pricing, i.e. by applying locational marginal prices (LMP) to each entry/exit point in the network. With nodal prices, congestion costs can be fairly allocated, and the congestion component can be hedged by market participants that hold physical or financial transmission rights.

   Locational marginal price (LMP) = System Marginal Price (SMP) +
   Congestion Component (CLMP) +
   Marginal Loss Component (MLMP)

   It is important to note that nodal pricing can also be applied to decentralized markets. Examples of decentralized markets that use nodal pricing include New Zealand and Chile.

   The CTBCM market design proposes centralized scheduling without nodal prices (even though nodal prices as the shadow costs of constraints are a direct output of the SCED).

[5] In the MW-km scheme, power flow and the distance between injection and withdrawal locations reflect transmission charges.

Instead, a single system-wide zonal price is applied across the network and congestion costs are assumed to be recovered with a uniform uplift charge.

The pricing methodology for transmission losses is explained in section 13.2 on the proposed approach to losses (page 76), which states that "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)". However, section 19 (page 95) on the consideration on transition to competition states that the cost of losses will be priced "as a separate cost component and its determination and charging mechanisms shall be worked out."

- **A nodal pricing scheme that uses locational marginal prices should be considered for fair allocation of operational costs such as losses and congestion. This will provide the right incentivizes for generators to be built in import-constrained zones and to avoid export-constrained zones. The wholesale price charged to domestic customers or the final retail prices can continue to be rationalized with a tariff differential subsidy.**

2. Which users are these costs recovered from?

US ISOs/RTOs allocate losses and congestion charges in the locational marginal price. The LMP is applied to every node in the network. Consumers (or loads) pay the LMP at the exit node where they take delivery. Similarly, generators are paid the LMP at the entry node where they inject power into the network.

National Grid ESO, Britain's SO, charges losses and congestion equally (50-50 split) to consumers and generators alike. Losses are calculated using Transmission Loss Multipliers (TLM). TLMs are zone specific, and there are 14 geographic zones.

The CTBCM design proposes to recover costs incurred from transmission losses and congestion from consumers. Section 13.2 (page 76) states that "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)". As allocation of congestion charges is not explicitly mentioned, it is assumed that congestion charges will also be entirely allocated to consumers.

- **Part recovery from generators for costs incurred due to transmission losses and congestion should be considered to give relief to consumers.**

3.4 Procurement and scheduling of Operating Reserves[6]

A System Operator can most efficiently operate a power system by ensuring fair and open access and full compensation to all providers of ancillary services. In particular,

- **Any resource capable of providing operating reserve services should be permitted to do so, and these resources should be compensated based on the net benefits they provide to the system. This includes not just power plants, but also energy storage**

[6] Operating Reserve is defined by the North American Electric Reliability Corporation (NERC) as "that capability above firm demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection." NERC further states that operating reserve "consists of spinning and non-spinning reserve". Operating reserves are also known as ancillary services.

systems and demand side management. In order to lower costs and enhance transparency in procurement, Operating Reserves should be tendered.

In decentralized markets such as Great Britain, generators are required to self-schedule. National Grid ESO "procures Balancing Services to balance demand and supply and to ensure the security of electricity supply". The list of Balancing Services includes Frequency Response Services, Reserve Services, Reactive Power Services and Restoration Services.

Centralized markets such as the US ISO/RTO markets co-optimize energy, transmission and ancillary services, albeit in different ways:

- PJM supports a coupled co-optimization[7] for energy and reserve in forward markets together with continuous real-time adjustments on the basis of real-time conditions.
- ISO-NE supports a decoupled co-optimization[8] for energy and Operating Reserve in forward markets, a coupled co-optimization for energy and Operating Reserve in real time, and a decoupled co-optimization for energy and Regulation in real time.
- ERCOT supports an integrated co-optimization[9] of energy and reserve in a day-ahead market and a coupled co-optimization of energy and reserve in real time.
- MISO, NYISO, CAISO energy regions support an integrated co-optimization of energy and reserve in both day-ahead and real-time markets.

PJM's scheduling of energy and reserve for each operating day D is handled by means of a forward Day-Ahead Energy Market (DAEM), a Real-Time Energy Market (RTEM), a forward Regulation Market, a forward Synchronized Reserve Market, a forward Day-Ahead Scheduling Reserve Market (DASRM), and an hourly re-scheduling process.

PJM determines market clearing prices (in USD/MWh) for "Regulation" and "Synchronized Reserve" as locational (zonal) prices based on supply offers, self-scheduled reserve, zone reliability requirements, and the opportunity costs incurred by marginal cleared supply offers for having to supply reserve rather than energy.

Scheduling of Operating Reserves in CTBCM

The CTBCM detailed design document states on page 50 that "generation is scheduled and dispatched by SO (security constrained economic dispatch based on variable generation costs and hydro optimization or water management), independent of contract commitments".

Therefore, the SCED used by the SO (NPCC) will be required to co-optimize energy, transmission and reserves.

The optimization algorithm would need to take into account:

a) Generator constraints such as ramp rates and minimum generation levels
b) Transmission constraints (for N-1 contingency compliance)
c) Contractual constraints such as "take-or-pay" agreements for RLNG power plants
d) Hydropower cascade water levels (from a water optimization model)
e) HVDC constraints (from the Lahore-Matiari embedded HVDC line)

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[7] Energy schedules and reserve levels are optimized separately, but with coupled constraints

[8] Separate parallel optimizations for energy and reserve without the imposition of coupled constraints

[9] Energy and reserve prices and scheduled dispatch levels are determined simultaneously as the solution to an optimization problem with a single cost function subject to a single set of constraints

- **A detailed analysis of the security constrained economic dispatch (SCED) methodology is required in order to ensure that a robust and reliable algorithm is selected which caters to the unique constraints of Pakistan's power system including the embedded HVDC line.**

3.5 Allocation of costs related to the use of Operating Reserves

National Grid ESO's Transmission Licence allows the SO to derive revenue in respect of the Balancing Services activity through the Balancing Services Use of System (BSUoS) charges. BSUoS charges are calculated and settled in accordance with the Statement of Balancing Use of System Charging Methodology.

- BSUoS charges are paid by all users of the transmission system, i.e. by both generators and consumers and are allocated equally in a 50/50 split.

On the other hand, US ISOs/RTOs assign reserve requirements to Load-Serving Entities (LSEs) on the basis of their relative shares of these loads. LSEs are free to provide their own reserves, to secure bilateral contracts for these reserves, or to purchase reserves in reserve markets centrally organized by the ISO/RTO.

- All seven ISOs/RTOs allocate the costs of operating reserve to wholesale buyers of energy.

Cost recovery of Operating Reserves in CTBCM

The market design of CTBCM proposes to recover costs related to Operating Reserves from consumers as a uniform uplift charge.

Section 16, page 89 states that "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."

It is also stated 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."

- **Part recovery from generators for costs related to Operating Reserves should be considered to give relief to consumers.**

Appendix A: Worked example of cost recovery for merchant generators

Market participants: generators G1, G2 and G3 and bulk power consumers BPC1 and BPC2

- G1 and G2 are located in zone A (e.g. Sindh)
- G2, BPC1 and BPC2 are located in zone B (e.g. Punjab)

<u>Generator operating costs</u>

- G1 (30 USD/MWh)
- G2 (40 USD/MWh)
- G3 (50 USD/MWh)

<u>Bilateral contracts for delivery in hour H</u>

- G1 has sold 200 MWh to BPC1 at 30 USD/MWh
- G2 has sold 50 MWh to BPC2 at 40 USD/MWh

The SCED determines that zone B is an import constrained zone in hour H (as per N-1 contingency compliance criteria). Transmission capacity between zones A and B is limited to 100 MW.

<u>Physical dispatch by SO in hour H</u>

- G1: 100 MW (part-load)
- G2: 50 MW (full load)
- G3: 100 MW (with start-up prior to hour H)

The SMP calculation proposed by the CTBCM does not take into account the marginal cost of G3 since G3 was only dispatched due to a system constraint. Therefore, the System Marginal Price in hour H is set by G2 (i.e. 40 USD/MWh).

Settlement for generator G1	**NETTA (UK)**	**CTBCM**
Cash IN from BPC1 (for bilateral contract)	200 MWh x 30 USD/MWh = USD 6,000	200 MWh x 30 USD/MWh = USD 6,000
Cash OUT to MO (imbalance)	100 MWh x 20 USD/MWh[10] = USD -2,000	100 MWh x 40 USD/MWh (SMP) = USD -4,000
Net cashflow	USD 4,000	USD 2,000
Full cost recovery	Yes	No

[10] The re-dispatch offer price is lower than the operating cost as the difference takes into account "make-whole payments" such as the shutdown cost, the next start-up cost and the cost of operating at a lower efficiency due to part-load operation as well as "lost opportunity costs".

Appendix B: A comparison of essential features of electricity market design

	Centralized markets: USA ISOs/RTOs (CAISO, PJM, etc.)	Decentralized markets: UK (BETTA)	Proposed CTBCM market design
Scheduling of generators and loads	• Market participants are not allowed to self-schedule based on their bilateral contracts. • Scheduling is done by the SO	• Market participants are required to self-schedule based on their bilateral contracts. • Any schedule changes due to redispatch by the SO (after Gate Closure) are settled at the bid or offer prices provided by the generator (or demand)	• Market participants are not allowed to self-schedule based on their bilateral contracts. • Scheduling is done by the SO
Settlement of energy volumes	• Energy generated (or consumed) is settled at each node (or hub[11]) using the locational marginal price (LMP). • LMP = System Marginal Price (SMP) + Congestion Component (CLMP) + Marginal Loss Component (MLMP)	• Market participants settle contracts bilaterally. • The imbalances between contracted and actual volumes are settled against the System Buy Price (SBP) and the System Sell Price (SSP) set by the balancing mechanism	• Market participants settle contracts bilaterally. • The imbalances between contracted and actual volumes are settled against the system marginal price (SMP), set by the SCED
Energy uplift payments	• Costs not included in LMP such as generator start-up and no-load costs, as well as demand response (DR) shutdown costs • Uplift = Make-Whole Payments + Lost Opportunity Cost	• Uplift payments not needed as market participants bilaterally contract taking into account all their costs in their bids/offers.	• Energy uplift payments not considered. Therefore, cost recovery for merchant power plants may not be adequate
Transmission capacity allocation	• Transmission capacity is allocated by the SO as part of the SCED optimization	• All market transactions up to 1 hour before delivery are carried out as if there was unlimited transmission capacity to support the corresponding flows.	• Transmission capacity is allocated by the SO as part of the SCED optimization
Transmission congestion management	• Energy, transmission and reserves are co-optimized by the SO as part of the Day-Ahead SCED run.	• In case the schedules resulting from the FPN are infeasible because of transmission capacity	• Energy, transmission and reserves are co-optimized by the SO

[11] Hub: an average price across a collection of nodes in a given geographical area

		limitations, the SO accepts the balancing offers to increase output from generators in the import-constrained area and balancing bids to reduce output from generators in the export-constrained area.	
Allocation of transmission congestion costs among market participants	• The Congestion Component (CLMP) represents the price of congestion for binding constraints. • Consumers pay the congestion price and Generators are paid the congestion price. • The CLMP is calculated by the SCED algorithm.	• Generators whose offers are accepted are paid the price of their offer for each accepted MWh. • Generators whose bids are accepted pay to the SO the price of their bid for each reduced MWh, while keeping the original contract position fully honoured. • Payments to generators for re-dispatch are recovered in equal share from consumers and generators as the BSUoS[12] charge.	• Congestion costs are to be socialized across consumers only as uplift payments • Congestion costs not paid by generators
Allocation of transmission losses among market participants	• Transmission losses are priced according to marginal loss factors which are calculated at a bus and represent the percentage increase in system losses caused by a small increase in power injection or withdrawal. • Consumers pay the loss price and Generators are paid the loss price.	• Transmission losses are allocated by scaling the metered MWh volume of each BSUoS user. • These scaling factors are called Transmission Loss Multipliers (TLMs). • The TLM calculation uses a parameter called the (G/D) split, which divides transmission losses between generators (45%) and demand users (55%).	• Transmission losses are to be socialized across consumers only as uplift payments • Transmission losses not paid by generators
Hedging of congestion costs by	• Firm transmission rights are purchased rights that can hedge congestion	• As re-dispatch costs are allocated on a "pay-as-bid" basis, hedging of	• Without LMP, costs incurred due to congestion cannot be

[12] Balancing Services Use of System (BSUoS) charges recover the System Operator's costs of operating the transmission system (to ensure that electricity is balanced on the system)

market participants	charges on constrained transmission paths. • Financial transmission rights (FTR[13]) are financial entitlements to the Day-Ahead LMP Congestion Component, i.e. the holder of the FTR is awarded a share of the congestion charges collected for that hour between the receipt and delivery points.	congestion costs is not required.	offset with physical or financial transmission rights
Procurement of Operating Reserves (also known as Ancillary Services or Balancing Services[14] in the UK)	• The ISOs/RTOs exhibit significant differences in their procurement and settlement practices for operating reserve. • All seven "co-optimize" energy and reserve, but in different ways, e.g. PJM's scheduling of energy and reserve for each operating day D is handled by means of a forward Day-Ahead Energy Market (DAEM), a Real-Time Energy Market (RTEM), a forward Regulation Market, a forward Synchronized Reserve Market, a forward Day-Ahead Scheduling Re- serve Market (DASRM), and an hourly re-scheduling process.	• National Grid ESO procures Balancing Services to balance demand and supply and to ensure the security of electricity supply. • Assets can be contracted under two services in the same time period if the requirements of each service are not conflicting	• "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" – section 16, page 89
Allocation of Operating Reserve costs among market participants	• All seven ISOs/RTOs allocate the costs of operating reserve to wholesale buyers of energy. • Specifically, entities servicing loads, i.e. Load-Serving Entities (LSEs), are assigned reserve requirements on the	• The Transmission Licence allows the SO to derive revenue in respect of the Balancing Services activity through the Balancing Services Use of System (BSUoS) charges • BSUoS charges are paid by users of the transmission system,	• "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

[13] https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/ftr
[14] https://www.nationalgrideso.com/balancing-services

4+6 = 10

	basis of their relative shares of these loads. • LSEs are free to provide their own reserves, to secure bilateral contracts for these reserves, or to purchase reserves in reserve markets centrally organized by the ISO/RTO. • The market clearing prices (USD/MWh) determined by PJM for Regulation and Synchronized Reserve are locational (zonal) prices based on supply offers, self-scheduled reserve, zone reliability requirements, and the opportunity costs incurred by marginal cleared supply offers for having to supply reserve rather than energy	i.e. by both generators and consumers • BSUoS charges are calculated and settled in accordance with the Statement of Balancing Use of System Charging Methodology	charge the market for that." – section 16, page 89

The Case for Alternative Electricity Market Exchange in Pakistan

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The Competitive Trading Bilateral Contract Model (CTBCM) is a highly intimidating, if not misleading, title. A new electricity governance regime is being introduced. The name is so intimidating that most people tend to stay away from it. All that CTBCM is offering is facilitation and institutionalizing large consumer choice, wheeling and competitive tariff-based bidding for new investments. One would like to do more to be able to have a functioning and truly competitive market based on tools and systems as applied in many regions and countries.

The system, proposed by the Central Power Purchasing Agency-Guarantee (CPPA-G) and approved by Nepra, does not seem to offer even a beginning in that respect. We would make a case for an alternative market exchange system as per standard practice in international markets.

Proposed CTBCM

The CTBCM system has essentially the following roles or functions. Simply speaking, existing power purchase agreements (PPAs) are transferred from a single buyer – CPPA-G – to several buyers, essentially distribution companies (DISCOs) and possibly large buyers. Capacity auction for new investments would be introduced based on competitive tariff bidding instead of regulatory pricing for new electricity investments. Roles of organizations would remain almost the same in the intervening period, which may be quite long as the life of existing PPAs is quite long. Only recently more than 10,000 megawatts have been added. The Private Power and Infrastructure Board (PPIB) will continue to promote and facilitate investments but as an auctioneer.

CPPA-G will continue to do what it is doing now. It will have a new section. It will be facilitating the conversion of current PPAs into bilateral mode.NEPRA will stop issuing tariffs and will oversee tariff-based competitive bidding undertaken by the PPIB. NTDC will continue to be a transmission company with possibilities of competition in transmission. National Power Control Centre (NPCC) would be an independent system operator with more independence. New market players would be introduced like wholesale traders? Wheeling would be promoted. Direct buying by large consumers would be promoted.

Taking Government Out of Market

The purported objective is to do away with “take or pay” liabilities, sovereign guarantees and government role in the electricity sector. However, the proposed mechanism may not be able to lead to this destination in the foreseeable future. If nothing else, competitive bidding would be introduced, but in the meantime Nepra is issuing tariffs at a rather fast pace. From single buyers to multi-buyers need not be such a compelling regime. It is working in India where electricity boards are buying and provisions for trading among large buyers and sellers are already there under wheeling arrangements in both the countries. If there are government-controlled DISCOs, what difference does it make, whether it is CPPA-G or a distribution company. Establishment of market exchanges has a much greater potential than CTBCM.

End of Uniform Pricing?

The most important aspect or consequence of CTBCM will be differentiated tariffs of DISCOs as opposed to the uniform pricing to which Pakistan's economic system is largely wedded.In federations or even otherwise, electricity prices do vary across states, provinces and regions. Thequestion is:being we ready for such transformation and are we preparing for it.I am not sure if people understand the implications of IPP-DISCO bilateral contracting as proposed in CTBCM. The issue should have been discussed by high-level policymakers than simply limited to the electricity or energy sector.

Towards a spot market exchange?

In a country having a history of corruption and collusion, bilateral contracts without market exchange would be a recipe for catastrophe. CTBCM can be amended to have a hybrid configuration. It is said that a major obstacle to having a market exchange is the longer-term PPAs. The solution may be a virtual market exchange with the following mechanism: PPA prices are taken as hedged prices and market players, as proposed in CTBCM, remain as these are. The difference is, however, that market players buy and sell in a day-ahead market. Daily market clearing prices are obtained and billed to buyers. Money is credited into the IPPs and wholesalers' account. Reconciliation is done monthly between PPA dues and market clearing prices. CPPA-G either receives or pays the residual.

There may be 25 DISCO buyer units and about 70 generators and 10 wholesalers. Derivative products such as forward prices and capacity auctions can also be introduced to guide new investments and capacity. IPPs may be encouraged under an accounting settlement mechanism to convert to market exchange. A secondary market may be introduced for the underutilized capacity. It is a transition instrument, converts PPAs into market exchange and inducts new investments through market products like capacity or forward prices. Alternatively, a small market exchange may be established wherein underutilized capacity and energy may be traded, like India's IEX. Roughly, the same may be done for the gas market.

Dealing with existing PPAs and other issues

There are some 56 power plants of 35,000MW, some PPAs are to expire shortly, some have entered into PPA in the last few years, some have and some have not retired their debt. It may be possible to develop and negotiate mechanism and financial arrangements for transferring PPAs into market domain. A policy would be required. It should be possible to acquire some liquidity for the market exchange over a period of two years or so. Following can be done in concrete terms;

1. Privatize GENCOs on selling assets basis and based on take and pay terms and being members of the exchange whenever it materializes.
2. Privatize RLNGCC plants on the same basis and possibly some hydros as well eventually
3. Allow IPPs completing their 25-30 years PPAs to compete in the exchange

4. Convert IPPs to market exchange, those IPPs to market exchange which have paid their debt. Continue paying the agreed amounts under PPAs under a price settlement agreement; the difference between market price and PPA price to be settled. If market price is higher, CPPAG/GoP gets the difference; if market price is lower, IPP is paid by CPPAG.
5. In the final round, deal with other IPPs which have yet to retire their debts completely. Same mechanism would apply for price settlement as in point 4 above.

6.All new PPAs to be under take or pay and market exchange rates basis. PPIB auctions or solicited acquisition through a CAPACITY market basis ala practice in the U.K.
7.As a complementary operation, convert DISCOs to wire-only. This can be done before or after privatization. The current CTBCM proposal of converting existing contracts to bilateral s with DISCOs becomes redundant. IPPs and other market players would then sell electricity directly to all consumers, irrespective of size. Alternatively, DISCOs continue to operate under existing arrangements but procure their need through the exchange.
8. NPCC (National Power Control Center) continues to work as a system operator planning and managing dispatches. The responsibility of making IGCEP is to be shifted from NTDC to NPCC.
9. NTDC to perform its core function with open and equal access mandate and a fixed tariff system.
10. For a considerable period of time, a hybrid and transition regime is to prevail. In his period NEPRA's role become even more significant. Eventually, NEPRA may have an oversight function to see to t that markets are working transparently.
11. PPIB-AEDB to continue performing facilitating role and transitional management, especially, with respect to sovereign guarantees and the associated negotiations.
12.A competitive fuel market is to be organized to assure a frictionless market regime in electricity sector-to-G fuel contracts are to be avoided and existing arrangement to be converted, if feasible. Qatar LNG may be sold at spot market prices and the deficit recouped as equalization charge from all user sectors. Preferably, a new local well-head gas formula may be introduced linking local gas price to spot LNG or some kind of average of several and relevant gas market hub prices.

Central Electricity Regulatory Commission (CERC) in India has announced similar proposals to bring all the electricity generated under one pooled market. There is an intimidating misnomer that the market has to be very big in order to have market exchanges. Most large and small countries in Europe are members of one exchange or the other. There is an EU directive that most countries should have their own hubs and exchanges.

Will Market Deliver?

Will the market be able to function transparently? Will it be able to attract investment? Will it be captured by the elite or mafia? Will it be able to facilitate poorer segments' access to energy? The alternative is government and bureaucracy. Demo models can be run and there may be a phased approach, starting with a market of 10,000MW.
Expertise can be hired. There are exchange-operating companies in Europe, which have the software, knowhow and experience to run energy exchanges. They would be happy to have a business opportunity. Training activities can be initiated remotely even now on their software.Concluding, market exchange is too important an institution to be ignored outright. Pakistan's market is no small as the capacity of 35,000MW will double in less than two decades.

Bilateral DISCO contracting is a move in reverse direction when the world has long moved into pooled markets. Bilateral DISCO-IPP contracts would be shifting sector management from a larger stronger system to weaker DISCO organizations involving many risks. Competitive pooled markets are the order of the day. One is not sure if Nepra has given sufficient thought to its determinations in his respect. Adequate consultation has not been made on all the available options and a prescription is being implemented as a fait accompli without considering and evaluating options. Higher national bodies such as the Senate Standing Committee on Power and others should be consulted on the larger social and economic impacts. The issue is too big to be left to technicians alone.

Philipines: From vertically integrated regulated system to Spot Market Exchange

The NPC's(WAPDA of Philipines) financial performance seriously worsened during the late 1990s. It was adversely affected by high debt payment and power purchase obligations. The deterioration was the result of several factors: ***the impact of the Asian financial crisis of 1997–1998, the subsequent depreciation of the peso, the high cost of take-or-pay power purchases from IPPs, and government reluctance to increase retail power prices.*** The government response was embodied in the EPIRA and called for radical reorganization and reform in the power supply industry. The plan involved (i) disaggregation of the industry into generation, transmission, distribution, and supply segments; (ii) introduction of competition in the generation and supply subsectors; (iii) introduction of a WESM; (iv) creation of the PSALM to manage the privatization of generation assets and transmission operations (but not of the ownership of the transmission facilities); (v) introduction of open access to distribution networks, and (vi) independent regulation

The MMS, financed and implemented with project support, formed the core of the WESM. Establishing the WESM was meant to enable distribution utilities and electricity suppliers to purchase bulk electricity directly from the generating entities or to buy it on the spot market. The WESM would make it possible for generated power to be dispatched on the basis of prices bid into the market, with the lowest priced electricity dispatched first. A well-functioning WESM with nodal pricing would provide the economic signals needed to encourage efficient investment in new generation capacity.

The evaluation found that the MMS has been highly effective. It has fulfilled its primary function of automatically enabling competitive market forces to help determine the amount, mix, and cost characteristics of generating plants to meet demand. Increased competition has led to the dispatch of power from the most efficient, and cost-effective power plants first, with the highest cost and least efficient plants being dispatched and providing energy to the market last. The MMS was scheduled to operate until 2012 but is still in service and not expected to be replaced until 2017.

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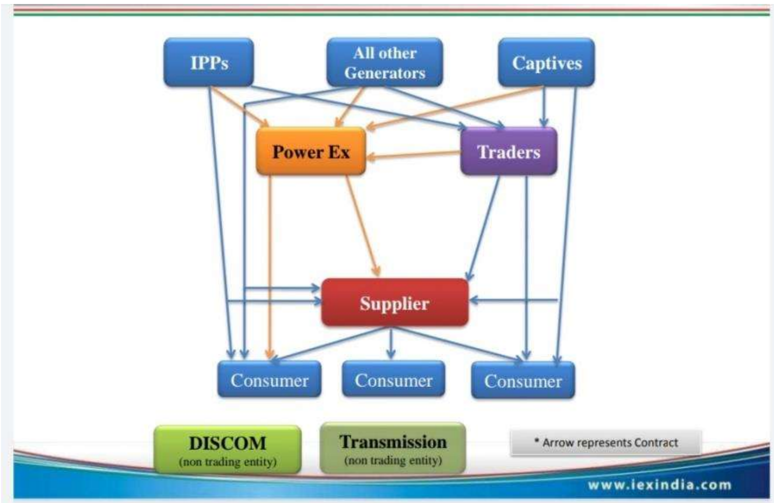
Extract from ADB Evaluation Report



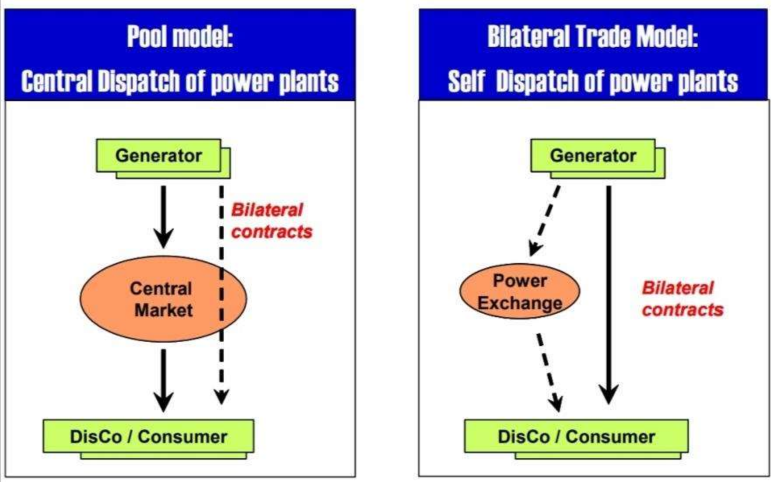


Figure 2. Pool model and Bilateral Trade model

Table 1 Overview of existing wholesale power markets in developing countries

Country	Year of market establishment	Type of market design established	Market size at establishment (yearly energy demand in TWh)
Nicaragua	1998	Cost-based	2.0
Bolivia	1992	Cost-based	2.3
Guatemala	1998	Cost based	4.3
Ecuador	1996	Cost based	9.1
Dominican Republic	2001	Cost based	9.7
Chile	1982	Cost-based	11.9
Peru	1993	Cost-based	14.5
Colombia	1994	Centralized bid-based	40.8
Philippines	2001	Centralized bid-based	45.2
Romania	2000	Centralized bid-based	49.6
Argentina	1992	Cost-based	53.4
Czech Republic	2001	Centralized bid-based	69.9
Poland	1999	Cost based	130.0
Turkey	2013	Centralized bid-based	228.3
Brazil	1998	Bid-based power pool centralized	317.0
India	2003	Partially centralized bid based	614.4
Russian Federation	2011	Bid-based	996.8

	EEX	ICE	GME	NASDAQ OMX	OMIP	OPCOM	PXE
Regions	BE, FR, GE, GR, IT, NE, NO, PH, RO, SP, SW, UK	BE, FR, GE, IT, NE, NO, SP, UK	IT	BE, FR, GE, IT, NE, NO, SP, UK	FR, GE, PT, SP	RO	CZ, HU, PO, SV, RO
Products	F, Opt, SP	F	Fo	F, Opt	F, Fo, Opt, SW	F	F
Delivery	F, Ph	F	F	F	F, Ph	F	F, Ph
Load Shape	B, P, OP	B, P	B, P	B	B, P	B, P, OP	B, P
Maturities	ID, D, WE, W, M, Q, Y	M, Q, Y	M, Q, Y	D, WE, W, M, Q, Y	W, M, Q, Y	D, W, M, Q, S, Y	M, Q, Y
Max. Maturity	Cal 22	Cal 20	Cal 17	Cal 19	Cal 20	Cal 17	Cal 19
Volume 2015 (1) [TWh]	2 537	171	517	1 496	170	30 (2)	22

Regions: BE (Belgium), CZ (Czech Republic), FR (France), IT (Italy), GE (Germany), GR (Greece), HU (Hungary), NE (Netherlands), NO (Nordic - Norway/Sweden/Finland/Denmark), Ph (Phelix - Germany/Austria), PO (Poland), PT (Portugal), RO (Romania), SP (Spain), SV (Slovakia), SW (Switzerland), UK (United Kingdom)

Delivery: F (Financial), Ph (Physical)

Products: F (Futures), Fo (Forward), Opt (Options), SW (Swaps), SP (Spreads)

Load Shape: B (Base), OP (Off-Peak), P (Peak)

Maturities: D (Daily), ID (Intradaily), M (Monthly), Q (Quarter), S (Semester), W (Weekly), WE (Weekend), Y (Yearly)

(1) Rounded to the neared integer. Includes OTC trading.

(2) Data from 2014 (only bilateral forward contracts)

NATIONAL TRANSMISSION & DESPATCH CO. LTD

General Manager (Technical)

No. GMT/NTDC / 1165-68/T-35 Dated 18 .05.2020

Mr. Iftikhar Ali Khan,
Director, Registrar Office NEPRA
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G-5/1, Islamabad.

Sub: **Detailed Design Report and Implementation Roadmap of Competitive Trading Bilateral Contract Market (CTBCM) Submitted by CPPA-G**

Ref: NEPRA letter No. NEPRA/ADG (Lic)/LAN-100/7979-23 dated 10.03.2020

With reference to above referred letter, the comments of the following formations of NTDC on subjected matter are enclosed.

1. GM (Power System Planning) - Annex-A
2. GM (System Operator) NPCC - Annex-B

This is for your information please.

Farooq Rashid
Engr. Farooq Rashid 18/05/20
Chief Engineer (C&M) NTDC
For General Manager (Technical) NTDC

DA/As Above

CC:

1. Deputy Managing Director (P&E) NTDC, 154-WAPDA House Lahore.
2. PS to MD NTDC, 414-WAPDA House Lahore.
3. Master File.

(ANNEX-A)

Power System Planning Comments on CTBCM Detailed Design

1. Page-15, Article 2.3 "Trading Agreements in the CPPA-G Market": The CPPA-G as an agent of DISCOs & KE for procuring power on their behalf, is not required to do forecasting function as Power System Planning department of NTDC is already performing this function as per Grid Code and prevailing practice. Duplication of any activity may raise conflicts.

2. Page-22, Article-4.2.2 "The System Operator: To comply with the Act, the System Planning function shall also be made part of the System Operator" and that System Operator will also be separated from NTDC, then in such situation who will own, prepare & update the combined Grid Code for NTDC and System Operator.

3. Page-23 Article 2.3 (Para 1), "Trading Agreements in the CPPA-G Market: NTDC as transmission services provider will ensure adequate economic transmission under the Planner function". It actually relates to Chief Engineer (Operational Planning) working under the System Operator.

4. Page-23, Article 2.4.2 (Para 2): "The planning procedures and standards will be in accordance with the Grid Code, guaranteeing predictability and transparency." The word "guaranteeing" need to be either removed or replaced with another suitable word in view of the on ground situations like litigations, land acquisition, ROW of ways etc., the construction of transmission lines and/or grid stations are delayed, thus in such a scenario NTDC cannot guarantee predictability according to the grid code or devised plans.

5. Page-22, Article 2.4.2 (Para 5): Clear time lines may be mentioned when the System Operator would start acting as a separate entity/company. Additionally, it has been mentioned that the System Planner shall also be made a part of the System Operator. It needs clarification, whether by "System Planner" shall be doing medium/long term planning or short term operational planning.

6. Page-19, Article 3 (Para 1): "In a competitive electricity market allowing the participation of wholesale buyers and sellers and bilateral contracts, each participant may have more than one bilateral contract". In this scenario, clear procedure should be delineated as how the impact of the Market Clearing Price and the Marginal Cost will be distributed amongst the different consumers in the grid because the marginal cost may increase because of any one consumer and without clearing defined procedures, the rest of the consumers will have to bear the burden. The consumers include, bulk consumers, individual consumers or DISCOs in case of transactions across CDPs.

7. Page-14, Article 2.2 (Para 2), Strict measures are required to be taken to discourage the formation of cartels that could resort to collusion and artificially hedge the Market Clearing Prices and the Marginal Costs. In this regard, the application of international practices in the local environment, need to be considered.

8. General Comment: Please consider recommendations given, during 3-day workshop held in LUMS in Dec. on the direction of NEPRA, pertaining to "Bilateral Contract Market" for inclusion in the CTBCM model.

(ANNEX-B)

NPCC Comments on CTBCM Detailed Design

NPCC has reviewed the Detailed CTBCM design. Until now, all preparation of SO for implementation of CTBCM was based on the high level CTBCM design approved by NEPRA. The implementation roadmap for NPCC as well as internal restructuring process was being carried out on the basis of high level design as well as the 17 action points prepared by CPPA-G. This included strengthening of IT department for maintenance of NPCC website, using software tools for operation planning, and digitization of current data exchange between NPCC and CPPA-G. However, in the detailed design, several other functions, that are currently carried out by CPPA-G (Market Operator), have been shifted toSystem Operator. This would require drastic changes, not only in the functioning of NPCC, but also in its organizational structure.

It is the view of this office that implementation of CTBCM be made incrementally rather than overhauling/disrupting current process flows at the initial stage. A brief overview is as follows:

Firm Capacity Certification

The prime responsibility of calculation of firm capacities as well as development of methodology of its calculation has been given to System Operator in the detailed design.However, the design of market and its functions are the mandate of Market Operator, and all relevant methodologies have been developed by MO. Therefore, given its experience and exposure, MO should design the methodology for calculation of Firm Capacity Certificates.

Further, the detailed design does not clarify what information would be required for calculation of firm capacity certificates and how this information would be acquired. Therefore, a detailed description of data requirements for this certification may be shared as soon as possible. A prerequisite for calculation of firm capacity is Annual Dependable Capacity (ADC) Test. It is mentioned in Section 12.1 that dependable capacity tests will be monitored by System Operator. However presently, CPPA is responsible for ADC and COD test activities and therefore, has good experience for conducting and monitoring these tests. In NPCC opinion, it is redundant to develop a new team for this purpose rather than using already experienced crew. Therefore, these tests must be performed in future market model by Market Operator.

Section 12.1 further states that firm capacity of hydro will be determined by simulation and optimization models. It is important to point out that water releases and inflow forecasting is not under control of System Operator in Pakistan, rather IRSA is responsible for hydel network monitoring and releases from large reservoirs. It is independent decision of IRSA to change water release from reservoirs based on demand of provinces. Therefore, it is not possible to use simulation for calculation of firm capacity of hydro power plants as no verified data/forecast is available for these calculations.

It is also mentioned that firm capacity for new thermal generation will be calculated on typical availability for similar technologies. However, it is not mentioned that how the new power plants are categorized for these calculations and who will be responsible for determining these categories.

In current PPAs, every power plant has forced and scheduled outage allowances which are calculated not only on basis of their forced outages and scheduled outages but also on basis of difference between actual availabilities and actual energies delivered. As actual energy delivered by power plants is accessed and verified by MO,it is not pertinent for System Operator to calculate these allowances.

In view of above detailed description, it is concluded that,

1. Methodology for calculation of Firm Capacity Certificate must be developed by MO.
2. Firm capacity must be calculated by the issuing authority i.e. Market Operator, being Contract Registrar.
3. Detailed data requirements for firm capacity certification are not shared in this report but in NPCC point of view, it requires large amount of data gathering and verification. This process is already carried out by CPPA and has developed an experienced force for this purpose for the last many years by dealing with different power plants. Therefore, MO must be responsible for this certification.
4. If System Operatoris made responsible for these tasks, a large number of skilled manpower would be required for collection and verification of data, calculation of firm

capacities, and handling disputes and arbitrage, of each individual plant. For training and development of such force, lot of time is required which will not only create hurdle for timely implementation of market but also requires much more financial resources, whichfrom NPCC point of view is not a viable option.

Merit Order

The detailed design proposes that all generators contracted under CTBCM regime would declare the variable costs to SO, and SO will prepare the Merit Order for dispatch of plants. At present, Merit Order is prepared by CPPA-G, being a commercial activity. For this purpose all relevant data regarding heat rates, fuel prices, O&M costs etc. are collected, checked and analyzed by CPPA-G. The final Merit Order is then submitted through a committee to Convener (GMSO) and is implemented for power despatch in real time operations.

In case Merit Order is prepared by SO and all related functions such as Heat Rate Test, ADC Test as well as financial checks and analysis are also carried out by NPCC, then it could cause conflict of interest as preparation and implementation of merit order is to be done by the same formation i.e. System Operator.

It is worth mentioning here that CPPA-G (future SPT) will continue to prepare the Merit Order for already committed plants as per respective PPAs. Thus, it will be a duplicity of operations if half the Merit Order is prepared by one formation i.e. SPT and half by the other i.e. System Operator.

Lastly, surveillance of market against monopoly and cartelization is function of MO. MO will implement several checks on costs declared by power plants and set generic technology-wise allowable ranges for heat rates and fuel costs. It is therefore strongly argued that Merit Order be prepared by SPT/MO as per current practice so that,

1. There is a single entity for preparation of Merit Order for whole generation pool
2. Effective market surveillance be carried out at time of its preparation.
3. The prepared Merit Order be approved by multi-tiered committee as per current practice.
4. Commercial Activities remain attached with MO whereas NPCC carries out technical activities only.

Calculation of Marginal Cost

In Section 11.3 it is mentioned that hourly energy imbalance price is calculated on basis of following information provided by System Operator,

- **Variable Generation Cost**
  - It has already been discussed that variable costs of plants (Merit Order) must be collected by CPPA-G.
- **Results Of Economic Dispatch (Daily Log Report),**
  - System Operator is responsible for spot MW despatch instructions to power plants whereas actual energy delivered by power plants is neither available with nor verified by System Operator. The design states that hourly energy figures from CDPs are used for calculation of marginal pricing. So, Daily Log Report (DLR) of NPCC cannot be used for calculation of Marginal Price.
- **Real time operation for that particular hour**
  - System Operator already provides all technical demand and dispatch data to CPPA-G including dispatch instructions, startup/shutdown events, forced outages etc. and will continue to do so.

The report does not clearly specify as to who will calculate the actual Marginal Price based on the above mentioned information. However, being a commercial activity, it is logically assumed that the calculations would be carried out by Market Operator as CPPA-G has already developed the methodology and software.

It is mentioned in Section 11.2 that "must despatch generation" is considered with variable cost zero but it is seen that no legal definition is present in Pakistan about definition of must despatch generation. If it is present in any legal document then that definition may be shared to avoid any confusions or ambiguity dealing this type of generation.

It is also given in section 11.2 that forced generation will not play any part in determining the marginal pricing of system. Therefore, this point requires clarification that who will pay the high cost of generation running in heavily constrained areas in system, as the marginal price of system at a particular time will be lower than generation running on costly fuel to cater system constraints.

It is mentioned in section 11.2 that opportunity cost of water storages will be considered as variable generation cost for purpose of optimization of water value model. But it is important to consider that there are indent restrictions in Pakistan for water releases from reservoirs. Therefore,hydro model must be developed keeping in view indent constraints of IRSA. It is also important to determine how opportunity cost of water storage will be calculated as it is not clarified in this report.

It is therefore recommended that,

1. The report is ambiguous as to who will be responsible for calculation of BME.NPCC recommends that BME price be calculated by MO as it is a commercial activity.
2. BME pricing which is calculated on basis of energy figures from CDP points must be calculated by CPPA as noenergy data from power plants is available in NPCC.
3. NPCC shall provide the relevant technical data regarding network constraints, take or pay fuel requirements, startup/shutdown events etc.
4. All the above mentioned points regarding hydro and system constraints must be considered in development of methodology for BME pricing.

Network Tripping

Since tripping of network equipment, both on primary (500/220 kV) and secondary system (132/66 kV) cannot be overruled in the daily system operations, therefore supply failure of either generator or consumer (due to network failure) will also create imbalance of energy in real time operations but would also affect the calculation of firm capacity of power plants for BMC. The detailed design is silent as to how trippings will be dealt with. In this regard, NPCC comments are as follows:

- Tripping of network equipment (transmission lines, circuit breakers, transformers) occur frequently in the system due to rain, fog, voltage fluctuations overloading, temporary faults caused by vegetation and human activities (kite flying, low line clearance areas etc.). A considerable portion of imbalances will be created due to trippings and methodology must be prepared in advance rather than considering them as a minute detail to be clarified later.

- It is unclear whether the market participants would pay the cost of imbalances due to trippings as system risk, or whether the respective Grid Company would bear the burden.
- Verification of tripping events cannot be carried out through SMS energy meters as these require instantaneous system parameters. In absence of SCADA, it would be impossible to determine the exact tripping times and thus create problems for exact calculation of imbalances.
- Each tripping event requires thorough investigation to determine if it was caused due to primary network, secondary network or internal fault of generator/demand participant. This is used for calculation of performance standards SAIFI/SAIDI. It must be clarified as to which entity (SO, NEPRA, MO, DISCOs, NTDC) would investigate the tripping while maintain transparency and neutrality in absence of SCADA.

It is therefore requested that,

1. A thorough methodology for handling network trippings be developed.
2. Allowable SAIFI/SAIDI limits for primary network should be defined, asspecified for distribution network.
3. The neutral entity for analysis of tripping events be mentioned.
4. It must also be determined as to how post-event analysis will be carried out in absence of SCADA.
5. A proper grievance redressal system must also be brought in place.

Miscellaneous

- All above mentioned functions have a high probability for arbitration and disputes since System Operator would become a gigantic central authority for calculation of firm capacity certificates, preparation of merit order, determination of hourly marginal price, conducting technical tests and audits, and justifying all its actions as a single entity to maintain transparency. This would require considerable investment in capacity buildingand manpower, not only in technical cadre but also finance and legal sector.
- Since PPA/EPAs of power plants would be signed with individual demand participants, there must be some form of agreement with System Operator regarding technical parameters in form of Connection Code or PSODA. The detailed design must specify the mode of this agreement.
- The design must also clarify the status of annual maintenance scheduling of power plants.
- The report segregates generation pool into dispatchable/non dispatchable plants. The said terminology is highly misleading as all plants available in the system are at the disposal of SO for dispatch. The plants, whether renewable or conventional, provide their availability to SO and it is the prerogative of SO to dispatch them economically keeping in view system constraints.
- As Contract Registrar, it the responsibility of MO to ensure that all demand participants have procured ample capacity to serve their peak consumption. In section 12.2.3, it has been erroneously attributed to System Operator.
- NPCC is managing its core task of power system operation, despatch and control with immense difficulties due to lack of essential tools and information. The hardship of NPCC is compounded with ever extending system and addition of variety of plants each having peculiar problems to deal with. The proposed restructuring on such a large scale is beyond the existing capacity of NPCC, hence it is requested that the international consultants supporting the restructuring of Market Operator be asked to carry out restructuring of SO.

hafiz.faizan@nepra.org.pk

Subject: FW: Comments of Omni Group on CTBCM Detailed Design Report and Implementation Roadmap

From: Gul Hassan Bhutto <bhutto.gulhassan@omnigroup.com.pk>
Sent: Tuesday, March 24, 2020 1:09 AM
To: registrar@nepra.org.pk; office@nepra.org.pk; info@nepra.org.pk; Imtiaz Hussain Baloch <ihussain@nepra.org.pk>
Subject: Stakeholders Comments Date Extension | CTBCM Detailed Design Report and Implementation Roadmap, March 24, 2020

Dear Sir, Registrar Nepra !
We have received NEPRA's notice on March 16, 2020 to our group 8 regulated companies (Dadu Energy, Thatta Power, Shikapur Power, Omni Power, TASML, ASML, BSML, CSML etc) asking to provide comments in the matter of "Detailed Design Report and Implementation Roadmap of the competitive trading and bilateral, contract market (CTBCM) model submitted by CPPAG in compliance of the directions given in the determination of the Authority dated December 5, 2019 for authority's approval and implementation,

We, being the group of 8 generation regulated stakeholders and affected parties are reviewing and working on CTBCM designed report and implementation roadmap, In our preliminary review the proposed model is seen as limited and isolated design based on "single-buyer plus" market development, which is none where implemented neither in any developing nor developed countries in world. We do not see any change in existing and newly proposed design model, once considering effect of NEPRA's wheeling of power regulations 2015 already in place. The pre-existing PPAs/EPAs deemed commercial allocation to Discos and retail supply envisaged to be retained as public sector entities regulated business (future unknown period of time),

We fully understand that CTBCM implementation has long impacts on the consumers, power sector and economy of Pakistan, so considering this issue of national importance, which required thorough deliberations across all stakeholder including the private sector, affected, interested parties and consumers. We are reviewing such a simplistic and assumptive CTBCM Detailed Design Report of CPPAG and comparing it with regionally and globally established wholesale electricity markets of the other developing countries with similar, bigger or comparative market size to Pakistan (having annual energy consumption 120 TWh). In our very basic review of global markets, which are decades old designed,established and operating models based on "centralized bid-based or partial bid-based or bid-based or cost-based" models deployed in developing countries with their annual energy consumption, Chile (11.9TWh), Philippine(45TWh), Argentina (53TWh), Poland (130TWh), Turkey(228TWh), Brazil (317 TWh), India (614 TWh), Russia Federation(996 TWh) and one of other developed european countries global biggest electricity market (3,300 TWh) etc.

As desired by authority, we have not been able to submit, our detailed comments on CTBCM model, as the workplace routines have been disrupted across Pakistan due to Corona Virus. In view of the prevailing situation of Covid-19 and subsequent lockdown in declared in all provinces including Sindh where our head quarters is located. We would request NEPRA to extend the deadline for submission of stakeholders comments on CTBCM model and revised comments submission date linked and scheduled within 7 days from normalization of business activities across the Pakistan.

The proposed and submitted CTBCM detailed design of Electricity Market would affect all private and public power sector entities of Pakistan. Hence, it is also important to note that CPPAG had not held any private stakeholder consultation session on the matter until NEPRA's solicitation of comments. Therefore, along with extension of deadline for submission of stakeholder comments, we would request NEPRA to advise CPPA-G to conduct stakeholder consultation to ensure all concerns have been addressed in the structure appropriately.

Thank you,

Kind regards,
Bhutto

Gul Hassan Bhutto
Senior GM Engineering & Operations
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WELT KONNECT

No: WKPL/NPERA/CTBCM/2020-01

Date: - 20th May 2020

P.S to Chairman,
NEPRA Tower Attaturk Avenue (East),
Sector G-5/1,
Islamabad.

ADG(Lic)

Subject: - **COMMENTS ON IMPLEMENTATION ROAD MAP (IRM) AND DETAILED DESIGN REPORT OF THE COMPETITIVE TRADE BILATERAL CONTRACTS MARKET (CTBCM)**

1) I would like to present my highest compliments to the honorable Chairman of the National Electric Power Regulatory Authority (NEPRA), Mr. Tauseef H. Farooqi and the respected Board Members of the Authority for requesting comments on the Implementation Road Map (IRM) and Detailed Design Report (DDR) of the CTBCM through publication dated 10.03.2020.

2) Please find enclosed comments/observations on the IRM (Annexure-I) and DDR (Annexure-II) respectively prepared after due scrutiny of the published documents during the COVID pandemic.

3) The efforts of the teams of the National Transmission and Dispatch Company (NTDC), the Central Power Purchase Authority (CPPA-G) along with the Consultants in preparation of the IRM and DDR for development of the CTBCM are duly appreciated. All comments given in writing are for constructive purposes only and are not meant to undermine in any way the good work which has been done by the respected teams.

4) We remain available for any further support that may be required for betterment of future energy/power planning.

CHAIRMAN
Dy No. 3260
Date: 29.05.2020

Thanks & Regards,

Habil Ahmed Khan
(Director Operations)

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Annexure - 1

Comments on the Implementation Road Map (IRM) of CTBCM

S.No	Comments	Para No.	Page No.
1.	If activities regarding detail design of CTBCM Model, training and capacity building were already in progress at the time of approval by NEPRA then what purpose would inviting comments to review the DDR and IRM of the CTBCM serve?		9
2.	The timelines provided for implementation of the structural changes proposed by the CTBCM seem overly optimistic and would require revision to bring them in line with ground realities and operational challenges of the energy sector	3	9
3.	The referenced Gantt Chart representing the activities to be performed by each Group/Stakeholder for implementation of the CTBCM is missing.	4	10
4.	It is pertinent to note that from the concept phase to Detailed Design Report to Implementation Road Map for the CTBCM, provincial governments have not been taken on board nor given representation on the team at CPPAG in charge of transition to CTBCM.	--	--
5.	The National Electric Policy (NEP) and other such documents which are part of the legislative requirements on the incumbent Government, must be produced and articulated irrespective of the transition towards CTBCM.	(table point 2)	11
6.	Critical progress is being delayed (since 2015) on the behest of such transitional work which may cost Pakistan dearly over the course of the next few years as energy demand surges with development of the CPEC and related infrastructure and manufacturing capacity of the country.	--	--
7.	If the Authority has already granted approval of the Implementation Road Map submitted with the CTBCM model, whereby the actions mentioned therein have already become regulatory directions for participating entities, then what is the purpose of inviting these comments by stakeholders through advertisement in the national papers?	3	17
8.	Terms of Reference (TORs) for the Implementation Roadmap of the CTBCM referenced to be provided in Chapter 3: Monitoring and Coordination, are missing.	4	17
9.	Adjustment of existing rules while development of new ones for the market structure is a specialized and sensitive subject, with each minute decision having far reaching consequences on the growth and development of the Economy of Pakistan (the average citizen, BPC and stakeholders), requiring experts, while the stipulated timelines for such work seems optimistic.	1	18

10.	The draft National Electricity Policy (NEP) is stated to be ready by April 2020, the review of the IRM cannot be complete without examination of the NEP.	5	18
11.	Review and amendment of existing GoP (Power) Policies by March 2021 seems optimistic.	7	18
12.	Joint Working Groups (JWGs) are being proposed only now for identifying the gaps in the existing policies, whereby critical analysis which should have predated the IRM of the CTBCM has been left unperformed, rendering the way forward uncertain.	8	18
13.	Although the NEPRA (Amended) Act 2018 is already in place, the regulatory framework comprising rules, regulations, codes and procedures need to be modified/developed for the CTBCM market to avoid challenges due to gaps, which seems rather untenable given the timeline and lack of critical analysis.	5	19
14.	Review of all the Policies, Rules, Regulation and Codes as envisaged in the Road Map requires massive efforts from the Joint Working Groups (JWG's) with exceptional coordination and analytical abilities, committing to the CTBCM before such scrutiny seems precarious.	--	18 – 22
15.	Bifurcation of the CPPAG into SPT and MO, requires careful consideration of the methodology for allocation of legacy contracts, a process which may have serious financial repercussions. While the creation of the SPT may adversely affect development of strategic projects in Pakistan.	3	22
16.	It is unclear under which section of the NEPRA Act (amended) 2018 shall the entity SPT be registered.	2	25
17.	NTDC under the current regulatory framework (in particular the Grid Code), is required to prepare the IGCEP (based on least cost generation) and the Transmission Expansion Plan (TEP) on annual basis for onward submission to NEPRA, the practice has only recently been taken up.	5	26
18.	Whereas the regression-based econometric long-term forecast at the system level with consolidation of the medium-term PMS based forecast of DISCOs, performed by NTDC, a highly critical task for an accurate Demand Forecast upon which the entire energy structure stands, is found requiring immediate overhauling and strengthening for effective decision making at the top.	5	26
19.	Plexos being a tool used for financial/economic modeling, is only as good as its user (defined algorithms/models), it is incapable of gauging/forecasting demand which is a different subject altogether or taking into view ground realities important for strategic decision making.	6	26
20.	It is necessary to ensure data security while designing systems such as the Secured Metering System (SMS) project.	2	27

21.	NTDC lacks capacity to draft Connection Agreements (and their implementation as required of it under the Grid Code) maintaining the balance required by all stakeholders for successful execution of Generation/Transmission Projects.	5	27
22.	The Data Institutionalization Project (DIP) should be carried out irrespective of the CTBCM project.	1	28
23.	Data security must be considered while development of a website by NTDC for sharing of sensitive information regarding power dispersal patterns across Pakistan with relevant stakeholders.	2	28
24.	Details are required to ascertain effectiveness and efficiency of the model that has been developed by NPCC for operational planning purposes intended to improve dispatch and processes.	7	28
25.	The details of the *state of the art tool* acquired by NPCC referenced in the IRM are missing.	1	29
26.	There is admission in the IRM that *NPCC lacks the capability to have an accurate demand and VRE generation forecasts which are the critical inputs to the unit commitment model,* which are absolutely critical for the good governance of any robust Power Infrastructure. This deficiency requires immediate redress irrespective of the CTBCM. Whereas the deadline kept for revamping of the system (by May 2021) seems challenging to say the least.	2	29
27.	Details are required of the Central Data Exchange Portal (CDXP) for which CPPA-G is facilitating NPCC, in automating core NPCC processes including dispatch instructions, plant availability, day-ahead dispatch, compliance to the dispatch instructions, etc.	3	29
28.	It is stated in the IRM that as per *initial discussions with NTDC IT team, it is agreed that the data storage and retrieval function of SO will be managed by the ERP data center of NTDC,* in today's day and age, better more efficient and independent IT solutions can be adopted	4	29
29.	Details of the functionality of the Market Monitoring System (MMS) to be developed by NPCC as per the Grid Code are required.	5	29
30.	It is unclear which entity shall be responsible to develop the SO website and whether data security protocols are adopted.	6	29
31.	Many improvements and upgradations in these departments especially NPCC, are unrelated to the CTBCM and should be pursued irrespective of the market design.	--	--
32.	It is stated that *DISCOs are required to have a dedicated interface to operate in the capacity of Electric Power Supplier and as such staff having specialized knowledge and competency to inter alia administer the bilateral contracts portfolio and perform short and medium-term demand forecasting would be inevitable,* the later	2	31

	should already be part of the activities performed by DISCOs and that too proficiently.		
33.	It is stated that the Association of DISCOs has been *long foreseen but not yet implemented*, firstly it is unclear which organ of the legislative or executive pillar of the state of Pakistan had foreseen such a development. Secondly it is further stated that *DISCOs will form their association by following the standard process...collaborate in the areas of mutual interest, watch their interest, and have their voice heard at the relevant platforms and forums.*, the standard process which they are to follow to form such an Association is left undefined. The urge/need to have their voice heard is rather surprising, being state owned entities are they not already a part of the state machinery. Thirdly it is stated that *This association will also enable DISCOs to have a combined representation in the Boards of different service providers and market participants, if required.*, creating a conflict of interest. Knowing the dynamics of Pakistan such a measure is likely to lead to managerial/operational complexity.	4	31
34.	It is stated that a concept paper shall be prepared and circulated by CPPAG for approval of NEPRA to define eligibility criteria of board positions for such associations however no details are provided. It is necessary to see such structure upfront to see the impact it may have on operations.	4	31
35.	Financial Health Assessment of DISCOs is an activity which should be carried out irrespective of any structural changes, it is part of the current regulatory regime, any good governance structure and should be undertaken by the Accountant General of Pakistan on a regular basis.	5	31
36.	Keeping in view the functionality of CPPAG, it seems odd to task it with the development of TORs for such an activity (Financial Health Assessment of DISCOs) in collaboration with AEDB/PPIB and hire a consultant.	6	31
37.	The *liaison mechanism* to be established for arrangement of Credit Cover/Guarantees through the MoE(PD) by the coordination of PPIB/AEDB (as IAA) is undefined and left open.	7	31
38.	Knowing that most DISCOs are low performing, would this not be another route leading to the same destination of Government Guarantees for Power Procurement, and if yes, it would be ill advised to create such uncertainty in the market which may lead to adverse unintended consequences.	7	31
39.	The allocation methodology and factors for the commercial distribution of PPAs/EPAs amongst the DISCOs by CPPAG (with *participation* of DISCOs), which is a critical aspect of the CTBCM	2	32

	is left undefined. Lack of clarity on the subject or even a minute error in allocation can lead to volatility in the Market/Economy.		
40.	It is necessary to see the composition of the Distribution Code Review Panel (DCRP) to gauge the effectiveness of the body. Whereas it is also pertinent to review the TORs/direction given to the DCRP for the suggested amendments.	7	32
41.	If the primary objective is to achieve procurement of power in the future through auctions, such is possible within the current regulatory framework through the PPIB/AEDB subject to all basic prerequisites being met.	1	33
42.	If the DISCOs proficiently perform their duties and responsibilities envisaged under the CTBCM, the role of IAA (AEDB/PPIB) will be limited to hosting auctions and strictly speaking not that of a Demand Aggregator (especially as each DISCO shall be free to pursue direct procurement under bilateral contracts).	1	33
43.	It is unclear how AEDB/PPIB entities established under their own Acts, will seek registration with NEPRA for performing the IAA functions, which may lead to legal complexity.	6	33
44.	The constitution and composition of the WG of the AEDB/PPIB (as also other WGs) for transition to the IAA needs to be provided in more detail.	9	33
45.	The functions of an auction house (IAA), if so required, could be handled by other entities.	3	34
46.	The process of drafting and approval of New Market Contracts to be prepared by IAA in collaboration of CPPAG (after assessment of the existing Security Package and Concession Agreements) is unclear.	3	34
47.	The mechanism to be adopted by PPIB/AEDB (IAA) for arrangement of guarantees/credit covers against exposure to imbalances for respective DISCOs and new capacity procurements is left undefined. Details are required to identify the effectiveness of such a mechanism.	4	34
48.	Capacity building can and should be conducted independent of the CTBCM implementation.	1	35
49.	In addition to LUMS, other renown universities, engineering & technical institutes such as GIKI, NUST, should have been involved in the policy dialogue for shaping of the structure.	1	35
50.	It would have been more apt if the Electricity Market Program (EMP) training would have been led by a public sector entity with open invitation to all stake holders.	3	35
51.	It would be prudent to confirm eligibility criteria of appointments/selections to the MIGs from the EMT (Electricity Market Team) leading eventually to the MIDs of the DISCOs.	4	35

52.	While all transitional aspects are being articulated the document seems to be silent on the process of the Auctions, which is one of the central themes to the development of the Structure.	--	--
53.	The structure creates an operational vulnerability for low performing & remote market participants (such as PESCO, QESCO etc and Power Producers) with resource rich jurisdictions but low consumption and low potential for sale.	--	--
54.	This may lead to serious problems for development of Strategic Projects in Pakistan as complex commercial interests may not always align with national strategic priorities.	--	--
55.	It is stated that *the methodology for the discovery of the marginal prices would be finalized...*it is unclear when such discovery would be conceivable. This being one of the most critical aspects of the Market requires special attention to address cost escalation concerns of all stakeholders.	2	36
56.	Treatment of losses in the current system is quite similar if not identical to what is being proposed.	5	36
57.	*Firm Capacity factor* is a familiar concept already in use whereas the proposed Methodology for its calculation in the system may be deployed now.	1	37
58.	Details of the Integrated Energy-Market Simulation Model are required for evaluation of the effectiveness of the underlying algorithms and iterative processes.	2	37
59.	If the ***main objective*** is to reduce government liabilities by eliminating sovereign guarantees, it is achievable within the current regime without need of much complex restructuring.	3	37
60.	If the ***goal*** is to attract investors for investment, such pull already exists, there are a number of projects pending approvals for investment today.	4	37
61.	Please elaborate on the *other changes* mentioned in the IRM.	5	37
62.	The statement *there lies a need to further refine the modalities associated with the features and intricacies of the market design after internal deliberation,* is admission of underlying problems in the structure.	6	37
63.	The statement *finalization of the elements of the detailed design would also contribute to designing the institutional structure of the Market Operator* is further implication of the gaps that exist in conception of the Market Structure.	6	37
64.	The above mentioned ***Main Objective + Goal*** can be achieved with minimal intervention today.	--	37
65.	It is stated that *to commercially allocate the existing PPAs/EPAs, it is necessary to define what share (percentage) of each PPA/EPA will be allocated to each one of the existing ten (10) ex-WAPDA DISCOs and KE.* Whereas the allocation factors that are to be used	5	38

	for such purposes are yet to be calculated, during the implementation phase, based on mechanisms which are yet unclear, adding to the uncertainty around the execution of the transition, with the potential of creating grievances against the federation for unjust or biased allocations.		
66.	Using the above mentioned commercial allocation of existing PPAs/EPAs for settlement of imbalances is tantamount to creating a problem and then solving it.	6	38
67.	It is imperative that the calculation methodology of the *Allocation Factors* be clearly articulated and spelled out for a more thorough examination of the environment that may be created by the implementation of such a structure.	6	38
68.	It is stated that the main feature of the CTBCM is to create a bilateral contracts market enabling trade between multiple buyers and sellers, however the problem is that even with such a structure (multi-buyer market) in place, there shall in essence still be one buyer, the State of Pakistan, as all DISCOs are state owned. An alternate route leading to a multi-buyer market would be through privatization.	--	--
69.	The existing PPA/EPAs contrary to what is stated offer a balanced approach to structuring contracts between generators and buyers, however violations of contract and circumventions of law/systems is a different subject altogether requiring to be addressed separately.	8	38
70.	Another ***main objective*** of elimination of the take or pay clause in contracts, may be achieved within the current framework. Additionally, while this clause seems to be abolished, it shall be replaced with a more complex system of capacity certificates, which shall more or less serve the same purpose in the envisaged market, and may ultimately end up with a higher aggregate cost. If the outcome is similar to (or worse than), take or pay why make such changes to begin with.	2	39
71.	*The principle difference in the legacy contracts and the new market contracts is that these are supply contracts under which generators have obligations to supply but not necessarily produce whereas the buyers have obligation to pay but not necessarily to consume,* in essence this is very similar to the system of capacity payments.	3	39
72.	Will such balancing mechanisms not add a layer of complexity to operations where the participants over the entire country will be struggling to keep pace with and track such changes.	3	39
73.	The allocation of legacy contracts, development of new bilateral contracts registered in the Contract Register, first creates imbalances which are then resolved by the balancing mechanisms which in turn requires each participant to sign a	6	39

	Market Participation Agreement (MPA) creating an obligation to abide by the balancing mechanisms, to pay or get paid for the imbalances, all of which is analogous to creating a problem and then solving it.		
74.	Market Data Institutionalization or simply Data Institutionalization should be performed irrespective of the CTBCM. Latest ERP/IT solutions can be used for synchronization of data across the sector in all concerned entities.	--	39-40
75.	The functionality and effectiveness of the SDDP tool of CPPAG for making financial projections/forecasts is untested and requires further investigation. Further it is unclear how investors have had access to and expressed willingness to use such an unknown untested system for making investment decisions in Pakistan.	2	40
76.	The MO in addition to the settlement function shall perform the Application Integration Architecture (AIA) work in consultation of NTDC and NPCC to work as middleware for data exchange/institutionalization using a modular system, it is unclear whether such a modular approach towards IT upgradation would be pragmatic or even necessary. It may be more effective to provide an architecture which provides real time integration while giving autonomy to each involved entity in their ambit of operations.	7	40
77.	The creation of Associations for Generators/ Transmission Companies/ Bulk Power Consumers seems self-detrimental and contradictory to the purpose of establishing the CTBCM for a free market.	--	40-41
78.	This initiative favors the larger corporations & groups with the rest at risk of being over shadowed.	--	40-41
79.	The *designated process* for establishment of such associations and mechanisms for being given representation/seats on the Boards of different Service Providers and Market Participants is left undefined, with clear potential for conflict of interest.	1	41
80.	Governance structure of the Transmission Sector companies is undefined.	3	41
81.	It is pertinent to point out that NTDC shall represent the Transmission Sector on the board of the MO and other entities till quorum of the Association of Transmission Companies is complete.	5	41
82.	It is stated *to smoothly start the market without disruptions*...clarification is requested on the type of disruptions foreseen.	3	42
83.	A number of questions come to mind on review of the IRM, with regards to the absence of critical policies, rules and regulations such as the NEP (National Electric Policy), the alignment of	--	42

	existing policies, and drafting of new rules, for implementation of the structure.		
84.	It is unclear if any commercial banks have been taken on board to discuss viability of commercial financing of PPA/EPAs to be made directly with better performing DISCOs.	3	43
85.	With government guarantees envisaged to remain in play the requirement of such massive restructuring is diminished.	7	43
86.	The transition is likely to create a lot of turbulence while the pilot phase needs to be articulated in detail.	15	43
87.	The composition and eligibility criteria of the Grid Code (GC) and Commercial Code Review Committees/Panels (CCRC) needs review.	13	47
88.	Lack of diversity in consultative workshops organized for private sector groups/market participants, raises questions on the effectiveness and impartiality of such forums.	-	48
89.	It is unclear as to how the DISCOs (especially financially weaker ones) shall arrange guarantees for new procurement and credit covers for exposure in the balance markets.	2	48
90.	DISCOs currently lack the capacity to structure, negotiate, execute and manage such bilateral contracts.	1	49
91.	The integration of Karachi Electric (KE) a Vertically Integrated Utility (VIU) into the CTBCM market lacks a clear road map, process or methodology. All options presented need further detailed investigation.	7	49
92.	The requirement on DISCOs to establish MIGs for the management of bilateral contracts, demand forecasting and planning, Arrangement of Guarantees/Credit Covers, Connection Agreements administration, registration and dealing with the MO as market participant, seems rather challenging in the current environment and condition of DISCOs.	5	52
93.	Criteria for assessment of financial health of DISCOs is unclear and should be managed by the Auditor General Office of Pakistan or Financial Consultancy Firms rather than CPPAG.	6	53
94.	It is pertinent to point out that the Association of DISCOs is the 4th Association envisaged to be created in Pakistan under CTBCM.	7	53
95.	Registration of AEDB/PPIB with NEPRA as Licensee under the NEPRA Act creates a conflict of Law, as these entities have been established under (their own) Acts themselves.	4	54
96.	Contrary to what is stated, the CTBCM adds several layers of risk on the generators and other participants creating an inherent upward pressure on prices whereby potentially making power more expensive in the system.	7	54

97.	The impact of Sovereign Guarantees on the credit worthiness of Pakistan needs to be investigated to come to a firm cost of such Guarantees and see what benefit, if any, may partially be derived from the CTBCM	6-7	54
98.	It is critical to note the market shall still be state-owned.	7	54
99.	The regulatory framework necessary for such CTBCM is undefined.	3	55
100.	While operational roles are defined, legal clarity is required on separation of powers/roles, as initially both the SO and TNO licenses are stated to be issued to NTDC.	2	56
101.	The inherent conflict of interest between the Supplier Business and Wire Business which each DISCO shall face till segregation occurs, has the potential to cause problems as the Suppliers may distort the market while the BPCs may feel discouraged.	--	
102.	The binding requirement on a BPC as per S.22 of the NEPRA Act 2018, of a one-year notice prior to leaving any DISCO shall add further financial burden to the private sector in Pakistan already facing several challenges.	5	59
103.	BPCs have largely been neglected while developing the CTBCM model. Not taking them into confidence has deprived the study of critical insights into the financial difficulties and operational challenges being faced by them in Pakistan due to the Power Sector.	--	59
104.	The Integrated Electricity Market Simulation Model (IE-MSM) Report is requested to be made public.	--	59
105.	There are legitimate concerns regarding the complexity of the MO settlement process and determination of the (hourly) marginal prices which demands further clarity/analysis of the subject. Algorithms for automation of the process need to be carefully scrutinized to identify any potential manipulations, disruptions or loopholes in the future, especially in terms of the ability to predict market behavior, which may be used by (or favor) one interest group over the other.	8	60
106.	The example of the telecom sector does not fare well, as in the energy sector almost all entities are state owned save KE.	9	60
107.	The notice period or frequency of entry/exit of a BPC from the market (to join a DISCO) needs to be defined.	11	60
108.	**Variable Cost (VC)** based merit dispatch order to be used by the SO needs further analysis.		

109.	The risk of Non-Project Missed Volume (NPMV) due to non-availability of the Transmission Network is parked with the Purchaser, its treatment in the future market is unclear and needs deliberation. If it is shifted towards the Generators it will result in higher risks in turn leading to higher costs	3	64
110.	It is pertinent to see weaknesses in management of the 132kV network by DISCOs and how it may be improved. Further it would be prudent to see the positive impact that the Independent Transmission Companies (ITC's) could have for such purposes.	2	65
111.	SCADA systems should be adopted in NTDC regardless of the CTBCM.	6	71
112.	It is requested that the draft NEP be shared.	7	73
113.	Although KE agreed to form an MIG along with DISCOs and also be part of the association of DISCOs, the modalities are yet to be articulated and confirmed.	5	75
114.	The output of the Working Group of CPPAG and KE is requested to evaluate the prospects of a single market across Pakistan.	3	76
115.	Bringing KE onto the Central Economic Dispatch to reap benefits of least cost dispatch by the SO(NPCC) while abandoning its own dispatch mechanisms needs to be reviewed in light of the contractual obligations of KE.	5	76
116.	It is pertinent to appreciate the procurement of power by KE without involvement of Sovereign Guarantees and without any CTBCM. The same could be replicated all over Pakistan.	7-8	76
117.	Security packages cannot be revised before finalization and approval of the revised/new power policies.	4	77

Annexure - 2			
Comments on Detailed Design Report (DDR) – CTBCM			
S.No	Comments	Para No.	Page No.
1.	As (iterated before and) stated in the DDR, the DISCOs have the right to contract/procure power directly from generators free of any legal constraints in the current set up, save CPPAG shall remain the exclusive broker for these DISCOs/KE. Whereas contract design, mechanisms for calculation & clearances of imbalances, with a competent human resource can be provided in the current regulatory framework.	1	13
2.	The statement that the *Market Operator typically is responsible for administering settlement and payment systems for centrally administered markets (imbalances and spot markets), not for bilateral contracts,* raises questions as to the suitability to have one for bilateral markets in Pakistan	7	13
3.	The extra burden (as implied by the language used) of the third role assigned to CPPAG to facilitate the transition from the current regime, would have been better taken up by the MoE (PD) under a committee of the legislative assemblies.	2	14
4.	It may be interesting to study the option of allowing DISCOs to directly contract EPAs/PPAs within the current regime with lesser complex modifications to the system (while also clearing any conflict of interest)	3	14
5.	Price manipulation is restricted in the current system as tariffs are determined by NEPRA. While manipulation of the system by a few IPPs is a separate subject better to be addressed in isolation	4	14
6.	Investors are ready to invest today (without the CTBCM) but are being held back by, not waiting for, the restructuring exercise.	4	14
7.	Poor demand forecasting is one of the more real and serious issues requiring immediate attention in Pakistan.	1	15
8.	Contrary to what is stated NEPRA conducts a very thorough scrutiny, public hearings + negotiations before determination of tariffs (for various technologies) often forcing companies to file appeals to make projects viable for execution.	3	15
9.	The reason why generation prices have not be determined by (or procurement done through) the market under the competitive bidding process prescribed by the NEPRAs Competitive Bidding Regulations (2017) is due to a limited understanding of the bidding process/requirements in terms of the technical, procedural and administrative functions which need to be fulfilled (and not CTBCM).	3	15

10.	It is a misconception that competitive bidding and CTBCM are correlated or one cannot be conducted without the other.	--	--
11.	Smaller power plants are already in bilateral contracts with DISCOs, if the purpose is to work on such arrangements, the practice can be scaled to include larger plants.	7	15
12.	Succession of EPAs/PPAs signed by WAPDA or NTDC to CPPAG for clarity and legal compliance in the system, should take place irrespective of the CTBCM.	3	16
13.	It is pertinent to note that monthly Fuel Price Adjustment of DISCOs and KE is carried out by NEPRA based on the monthly energy procurement data shared by CPPAG, an activity which is not part of the current commercial code.	3	16
14.	The importance and difference between non-coincidental demand peak and coincidental demand peak of DISCOs is linked to proper planning (demand forecasting and pattern recognition) and management of the sector.	--	17
15.	The average monthly transfer price calculations based on a sharing principle (for transactions/settlements today) has the subtle advantage of supporting weaker DISCOs (while potentially also subsidizing larger ones).	4	17
16.	Finishing the price sharing mechanism/principle may have the undesired effect of opening up price differentials (in territories/jurisdiction of each DISCO) across the country, creating market segregation, which may adversely impact economic development in some areas while incentivizing others.	2	18
17.	The market imbalances (in terms of energy & capacity) created by CTBCM operational systems and contract designs are then resolved by balancing mechanisms, which is tantamount to first creating a problem and then finding a solution (an expensive one at that).	1	19
18.	The explicit allocation of losses to market participants/stakeholders should and can be done today without CTBCM, which may also be used to gauge performances of entities.	2	19
19.	Security of supply for buyer and performance/availability obligations on sellers is prevalent in the current system.	4	19
20.	It is pertinent to note that *The CTBCM is designed as a bilateral contract market with balancing mechanisms*, it is however unclear whether an analysis has been conducted on what kind of market design (with customization to suit local conditions) would be most suitable for Pakistan and why.	7	19
21.	It is admitted that almost all service providers shall remain the same, meaning changes are rather commercial/financial in nature which may have far reaching political and administrative effects.	6	21

22.	Hedging of prices based on portfolio of contracts, as a derivate (financial) market as the CTBCM structure develops may have the undesired effect of complicating the system through speculation and raising costs.	7	21
23.	By making mandatory for small generation companies selling to BPCs to become market participants, captive power business models or wheeling arrangements shall practically cease to exist.	5	24
24.	The competitive supplier regime intended to be initiated from BPCs and introduced to commercial and other consumers as the market matures, has the potential of driving prices higher as in a few years NEPRA shall lose control of consumer tariffs.	2	25
25.	The capacity requirements imposed on Market Participants under the CTBCM is similar to the capacity arrangements today, different only in nomenclature but similar in essence.	4	25
26.	Transaction of data from metering service providers to suppliers can lead to operational and administrative complexities.	5	25
27.	It is critical to note that generation in AJK and other jurisdictions not covered under the NEPRA Act shall not be assimilated in the Market and shall become a Participant through or by virtue of becoming a Trader (example of Neelum Jhelum HPP has been sited), hence hanging by a thread in the overall scheme.	5	26
28.	Majority of the targets listed are either in practice or can be achieved with slight modifications in the current regime, save the balancing mechanisms which would not be needed.	1	27
29.	The often irrational or peculiar behavior of consumers in Pakistan can lead to over subscription (over-sizing) or under subscription (under-sizing) of capacity certificates to meet their capacity obligations under the CTBCM, driving prices and demand estimates high or low, due to lack of know how or educated decision making.	8	27
30.	Coupled with severe penalties for (capacity) violations can potentially lead to acute volatility in the designed market.	3	28
31.	The basic underlying problem is lack of detailed demand analysis/forecast, no linkage/integration with national economic objectives, which must be corrected on war footing for things to improve.	5	28
32.	The ability of BPCs to provide 5 years advance forecast of capacity seems limited and can lead to unexpected results in the Market structure being proposed.	6	28
33.	Modification of existing PPA/EPAs (and PPAAs) of DISCOs + KE in light of the amended commercial code (requires further investigation) such that they are administered by the SPT as if they are bilateral contracts signed among the DISCOs, may have been a better place to begin prior to making the decision to transition completely. This temporary transitional arrangement	11	30

	would have provided strategic practical insight of the underlying challenges of the system.		
34.	The impact of usage of contracts as financial instruments for hedging of prices needs further investigation through market simulation & modelling (while VRE & Hydro projects are inherently hedged, this may be more applicable to fossil fuel based projects/instruments).	4	31
35.	With contract prices hidden (except for existing PPA/EPAs) and registration of only generation prices (variable costs) with MO for Security Constrained Economic Dispatch (SCED) there is need to simulate impact of manipulated/ inaccurate information dispersal.	6	31
36.	Initially collective procurement by IAA followed by signing of bilateral contracts with each DISCO shall render complex the administration and management of such arrangements.	3	32
37.	On the other hand dispatch of efficient power plants as per SCED even if not contracted (or partially contracted) under the BME mechanism, subject to being a Participant or represented by a Trader/Supplier, may undermine the need for having auctions/contracts (under heavy regulations meeting which has an associated cost) to begin with.	2	33
38.	While the concept of BMC is relatively simple on paper, its actual/physical impact and financial implication are not. It has the potential to burden demand participants while confusing others. The delay in its initiation by 2 years after CTBCM may not help resolve the inevitable volatility/complexity it shall induce in the market; tantamount to creating a problem then solving it.	12/1	33/34
39.	It is stated that in the BME prices for generation will result from competition to dispatch under SCED, with (fixed & variable) costs contractually aligned; it is unclear what kind of competition is expected with prices/costs fixed, while resulting in undue pressure on generation (discouraging investment through diminishing returns with uncertain dispatch).	4	34
40.	The requirement of credit covers by the MO for payment of imbalances under the Centralized Payment System (of the Centrally Administered Markets – BME & BMC) shall further create a barrier to entry by burdening Participants who may find it difficult to furnish such guarantees. Whereas banks/financial institutions would benefit and be content with such requirements.	7	34
41.	The security cover mechanism requiring coverage of each participant for each transaction shall make operations more cumbersome, complex and costlier than the current regime of security covers/sovereign guarantees. Macro analysis of the arrangements is required to ascertain and comprehend the aggregate costs of such a system to Pakistan. The existing security measures largely cover the exchanges under question.	--	34/35

42.	The culture of non-payment in Pakistan which may be a serious impediment is self-acknowledged.	9	34
43.	It is pertinent to note that the Physical Product / Energy is not controllable through contractual arrangements. In other words, the mechanism of dispatch shall work in isolation of the market, which may contribute to the risks outlined above.	3	36
44.	It is admitted that the capacity *trading product is created by the capacity obligations imposed on demand participants in the market design,* similar to creating a problem and then solving it.	8	36
45.	Consumers including (BPCs/eligible consumers) may contract lower capacities than actually required while utilizing higher capacities frequently around the year except the stressed monitoring period during which Market calculations are conducted.	--	39
46.	The standard practice of having demand pay for losses is prevalent even today (up to the levels allowed by NEPRA).	1	41
47.	It is acknowledged that different contracts in the CTBCM may lead to different prices.	2	41
48.	Generation Following Supply Contracts (GFSCs) pose the inherent risk that under SCED the generator may receive partial (or no) dispatch making its sustenance extremely difficult.	7	41
49.	It is pertinent to note that GFSCs with provision of capacity obligations coupled with the restriction of only one buyer, it becomes similar to the existing EPAs/PPAs also in regards to the single buyer model (although the current practice of CPPAG in essence is in representation of multiple buyers).	9-11/1	41/42
50.	It is pertinent to look into the peculiar case where Generation and Demand have mutually exclusive/different profiles, both or each may find itself making settlements (getting paid or paying) in the BME at the system (marginal) prices.	--	43/44
51.	The effect of (take or pay) fuel commitment as fixed price on capacity prices needs further examination as cost of take or provisions is not taken into account for the capacity price.	Footnote /6	44/45
52.	It is admitted that in Pakistan take or pay energy clauses played the role of (some kind of) capacity payments to ensure minimum availability, similar to what the CTBCM aims to achieve, while the structure becomes more complex (and expensive) the functionality remains the same.	5	45
53.	Even in Load Following Supply Contracts (LFSCs), with multiple Generators, it is inherently assumed that Generation and Load profiles shall overlap (at least partially), which may not be the case due to the SCED, hence depending on the Contract details, both the Buyer & Seller may be exposed to the BME market.	--	47/48
54.	The function of Financial Supply Contract With Fixed Quantities (FSCFQ) disconnecting actual generation from dispatched	5	50

	generation/physical quantities is similar to the methodology of LFSCs, only difference is the exact quantity of energy/units contracts instead of percentages (hence both may result in similar scenarios).		
55.	In FSCFQ the Generator faces the risk of not being dispatched and having to settle the contracted quantity of energy at the BME price which may be higher than the contractual price hence causing losses.	4	51
56.	With a fool proof fully automated system there should be little or no concern about transparent economic dispatch for efficiency of such contracts, as the algorithm should be making these decisions. The concern implies existence of gaps in the system.	8	51
57.	The option to sell excess energy in the BME Market needs to be checked as there is potential for misuse.	7	52
58.	The requirement of Demand Participants who have contracted energy-only generation to separately meet capacity obligations through procurement under Capacity Only Contracts (CoC) shall burden VRE development under CTBCM.	4	53
59.	Contracts selected by DISCOs in the CTBCM shall only remain under the purview and approval of NEPRA until they are licensed as suppliers where after they shall be free of such scrutiny	2	56
60.	The selection of the Contract type for allocation of (percentage of Energy and Capacity from) existing PPAs/EPAs to DISCOs, if left unchecked, can have the undesired outcome of market segregation with tariff differentials based on varying costs of generation for each, due to inconsistent/different demand profiles, making it a highly sensitive subject.	7	56
61.	The uniform per unit generation costs charged to DISCOs and KE under the Energy and Capacity Transfer Charges (ECTC) applied to energy demanded by each and proportionally to the peak demand of each, are in essence subtle balancing strengths of Pakistan whereby disadvantaged/under developed areas are supported through sharing of costs. DISCOs with lower load factors shall (pay proportionally more for capacity than for energy and therefore) have higher generation costs and vice versa.	8/1	56/57
62.	The figures depicting changes in Averages Generation Prices from 2017/18 to 2024/25, confirms that: (i) Overall costs for energy & capacity increase for all DISCOs; which shall in turn make almost everything else more expensive in the economy, leading to higher costs of living and doing business, hence further burdening economic growth and development in Pakistan.	3	57

	(ii) Cost differentials between DISCOs are observed to be amplified which shall put pressure on NEPRA for maintaining price uniformity eventually leading to Market segregation in the Country. (iii) Potential for increased provincial grievances, divisive economic growth.		
63.	Leaving sensitive matters to be decided during the implementation phase of the CTBCM seems to be a common theme thought out, which may have the effect of leaving little or no time for reconsideration.	4	57
64.	Methodology for allocation of Contracts left to be decided during implementation phase. It would be better to indulge in and address difficult subjects now than leave them for later.	4	57
65.	Formulae for calculation of Energy (& Capacity) Balancing Prices under SCED needs to be shared.	8	58
66.	Templates of the Market Participation Agreement (MPA) and all other basic Agreements/Contracts to be used in the CTBCM (assuming basic drafts exist) should be immediately provided for scrutiny.	9	58
67.	As stated CTBCM shall inherently remain imbalanced due to Bilateral Contracts being implemented on a shared network with varying actual generation & demand, requiring balancing to operate.	1	59
68.	It is unclear how the CTBCM being based on bilateral contracts may provide price signals as to the lack of adequate reserves or surplus generation, its functionality is distinct from exchanges.	5	59
69.	Methodology for calculation of marginal prices is not provided.	5	59
70.	While import of energy shall be registered through a Participant as Generator, the contract shall be outside the market, with energy schedule coordinated between the relevant cross border system operator and SO treated as committed energy at least a day in advance and imbalances calculated accordingly, it would be prudent to further delve into the calculations and impact of such transactions/arrangements. Similar arrangement is envisioned for exports with Participant being treated as a Demand.	8/5	59/61
71.	Will the energy balancing price considerations (i. must run shall have zero variable cost ii. forced generation for system security constraints shall not be taken into account iii. for hydro with reservoirs opportunity cost of water value shall be used) not keep it unrealistically low, giving arbitrage opportunity to certain players.	6-9	62

72.	Details of the water value model are not provided.	9	62
73.	Details of the software and model to be used by SO for generation scheduling and dispatch are not provided.	10	62
74.	It is stated that the detailed methodology shall be developed by MO and approved by NEPRA, it is critical that it be articulated and shared now for scrutiny of its impact on the market (and related transactions).	12	62
75.	The CTBCM seems to discourage Generation as a whole, as dispatch shall remain uncertain, while it is plausible that the Generator will end up with negative balances owing to different contract designs and generation/demand patterns (paying marginal costs for settlement, which may be higher than his own variable generation cost owing to difference in generation and demand profiles, while ideally in the market negative imbalances should only be created if the variable generation cost in the system is lower than the generators variable cost).	--	63/64
76.	There is risk that generators with a high variable cost may not get dispatch under SCED, however it may have contracted energy (or capacity) quantities with Consumers/Demand that may end up being accommodated by the Market at lower rates, while the Generator continues to make a hefty profit despite paying the marginal cost to the Market for the imbalance quantity.	--	63/64
77.	The methodology to be used for calculation of Firm Capacity of VRE projects is left undefined.	12	65
78.	The methodology for calculation of the critical hours for capacity balancing purposes (of capacity provided by generators and taken by demand) is left to be developed by the SO and approved by NEPRA, details are requested for analysis. During initial development these hours have been disclosed to be those in which demand is highest (as opposed to when reserves are lowest).	6/12	66
79.	It is unclear which entity has been given the role of Central Planner for the sector, pertaining work which is critical to future growth and development.	2	70
80.	It is pertinent to note that in addition to procuring Capacity to meets its obligation under the CTBCM, each market participant shall also need to provide appropriate guarantees to cover its expected position in the Balancing Mechanism for Capacity.	8	73
81.	May lead to a scenario where certain participants may find it more beneficial not to sell their capacities and wait for the BMC to be awarded balance payments/amounts.	--	74
82.	Non adjustment of transmission losses recovered from consumers not purchasing from DISCOs from the total amount to	8	75

	be paid by the DISCOs for such losses is an error in the system which should be rectified irrespective of the CTBCM.		
83.	The proposed solution, of uplifting the metered energy of Demand Participants to include a percentage of transmission losses, while if such losses are above the cap prescribed by NEPRA for the period, the difference shall be returned on pro-rata basis to the demand participants, is similar to what is happening today, with the difference that losses are jointly shared amongst all Demand Participants (DISCOs + KE) with the subtle variance that a portion of such amounts are explicitly charged as part of the Variable UoSC (which in the current system is applied to generators selling directly to BPCs, which are almost non-existent while almost 100% of energy is delivered to DISCOs + KE and these losses are made part of the calculation of energy bought).	2-3	76
84.	Basically Variable UoSC would be finished and Fixed UoSC shall continue to be applied explicitly (rather than implicitly) to all demand participants as is the practice today.	5	76
85.	It is acknowledged that the proposed approach to handling losses is similar (technically identical) to the current practice in Pakistan.	7	76
86.	It is pertinent to note that as losses in the Distribution Networks are not metered every hour, standard values given by NEPRA shall be used to uplift the demand in the DISCOs to account for losses. Advanced hourly metering at DISCO level should be adopted prior to implementation of the CTBCM.	10	78
87.	The uplift of demand of a BPC embedded in the Distribution Network first by the Distribution Losses followed by the Transmission Losses presents a case of Double Jeopardy, resulting in an advantage for BPCs directly connected to the Transmission Network.	--	80
88.	Reconciliation may be performed annually (initially) or monthly (later) depending on NERPAs decision on the period.	2	80
89.	Method for calculation of the Average Marginal Price of Energy to be used for working out the amount NTDC may have to pay the MO for the % transmission losses (energy) higher than that allowed by NEPRA, is left to be decided during the implementation phase.	3	80
90.	The system of centralized competitive auctions where the PPAs/EPAs are to be signed by each DISCO for their demand, would expose weaker DISCOs to high-risk premiums, as sellers/generators would need to account for such risks, in addition to factoring in the location (whether it is in the vicinity of such a DISCO) or the magnitude/capacity of the project which may be important in calculation of such costs/premiums.	3	84

91.	The methodology for execution of the Capacity Procurement Plan (CPP), to be prepared by the IAA (taking into consideration IGCEP, TEP, other constraints & investment) under the provisions of the Procurement Regulations to be promulgated by NEPRA, needs to be carefully scrutinized. As factors such as quantity to be auctioned, capacity/energy or both, technology neutral/technology specific, scale capped or open, can have a significant impact on the outcome.	2	85
92.	Special auction for accommodation of large scale hydro power projects within the auction system is also left undefined.	2	85
93.	The IAA would not be the most suitable to assess the financial health of DISCOs. Being state owned relatively large distribution entities the DISCOs are obliged to conduct financial audits/analysis on regular basis to assess their operations, while the Government or more specifically the Ministry of Energy Power Division must be vigilantly monitoring and gauging the performance of each entity, it is alarming that they would require the services of a Board (IAA) working solely on promotion of renewable energy since inception, to perform such analysis. It would be better if the Ministry of Finance or a similar arm of the state/government such as the Auditor General of Pakistan well versed with financial systems was to perform such analysis, if such audits are not already being carried out.	6	85
94.	The Guarantee Support Scheme (GSS) envisioned to be provided by the GoP to support financially weak DISCOs meet their credit requirements to participate in the CTBCM, administered by the IAA, requires more detailed explanation for analysis. The GSS is in essence similar to Government guarantees being currently provided.	6	85
95.	If the objective was to initiate procurement of Power through DISCOs through competitive processes where possible, providing government guarantee covers where applicable, this could be achieved under the prevailing system without massive restructuring.	--	85
96.	Given the process for transition towards CTBCM has been active since several years, a diligent in depth Gap Analysis of the Policies should have been performed by now.	2	86
97.	It would have been preferable to solicit comments of stakeholders on the IRM & DDR prior to approval.	4	86
98.	Contrary to what is stated, most public and private power projects are developed through involvement of bidding processes in one form or the other, while raw sites are awarded through a qualification process to the most deserving/competitive companies.	5	86

	Whereas tariff determination for projects has been conducted by NEPRA under thorough and rigorous processes of the cost plus mechanism or FITs (feed in tariffs). As stated earlier Auctions can be conducted within the current regulatory framework provided all prerequisites are met.		
99.	Drafts of the new/amended Codes are required for further analysis.	--	86-87
100.	Initially ancillary services shall be provided by all market participants without compensation (rationale being that such services are already catered for by the existing PPAs/EPAs and as such should not be charged separately, being paid for by the demand), however later may be chargeable, this aspect needs to be elaborated.	3	89
101.	The SOP to be developed for verification of Variable Generation Cost being provided by the Generators directly impacting dispatch is not provided, hence its efficacy cannot be determined. Further investigation is required to see the impact of false/inaccurate data being fed into the system.	4	89
102.	An arbitrage opportunity for retiring plants which have already recovered their fixed costs and have very minimal variable costs is recognized however selection of an appropriate solution to cater the problem is left to the implementation phase, there is a need to perform further analysis of the subject.	5-8	89
103.	While it is stated the Market Operator shall make several calculations of prices/charges for instance transmission use of system charge (UoSC), the mechanism is not defined.	13	90
104.	The envisaged credit systems shall increase financial costs on the participants, ultimately causing them to raise energy costs, for the end consumers.	10	91
105.	Such a system will favor larger corporations while causing disadvantage or barrier to entry for SMEs.	--	91
106.	It is pertinent to have a system which has been developed keeping in view the complexity involved in the balancing markets, if it has, it should be shared, it would be prudent to perform due diligence on the envisioned modelling.	--	91 – 92
107.	Publishing of detailed information of each and every system online on websites can reveal consumption patterns throughout the country, with a resolution of up to the meters through which connections are made, is a data security risk.	6-7	92
108.	It is unclear how lenders shall be convinced that the exposure to the market is a predictable and a manageable risk when there is uncertainty regarding numerous moving parts of the CTBCM.	6	92

109.	Having a robust automated system with effective algorithms audits should be conducted at a higher frequency (best to have real time checks in the system) to ensure compliance (biannual at least) and not after 2 years. (The need for audits implies there is room for human intervention meaning the system may not be as reliable as portrayed)	5	93
110.	Without a detailed system architecture of the CTBCM to cater for IT requirements for implementation it seems rather risky to proceed. If such systems exist, their blue print must be provided for further due diligence.	8	93
111.	It is interesting to note that KE while remaining outside the system (with the subtle difference of receiving fixed quantity from the legacy PPAs/EPAs instead of % as the DISCOs) is allowed to have bilateral contracts based on the Least Cost Generation Plan and TEP of the KE system. While purchasing form the Market as a Supplier for its regulated consumers and selling surplus.	3	94
112.	Mechanism of integration of KE into the CTBCM to enable bilateral trade in its area is left to be decided (in light of provisions of the Act and concession agreements of KE) during the implementation phase, along with other crucial and key items of the CTCBM before it.	5	94
113.	Bifurcation of costs of different services and components already exists though the consumers are not exposed to it in the current regime.	2	95
114.	The self-acknowledged, unintended consequence of demand exiting a VIU or Single Buyer with Legacy Contracts in place with costs (for capacity + energy) will create disorder in its area/jurisdiction whereby the brunt of such cost shall fall on the demand/consumers which are left in it, while those who leave may enjoy much lower costs. (High risk problem with a less than apt solution proposing to take the implementation of CTBCM slow with little or no substance attached to such a proposition)	3	95
115.	To achieve the objective of providing a level playing field under the CTBCM, the removal of cross subsidization (amongst other things) employed by Pakistan to meet certain strategic social and economic interests of the country is proposed, which will potentially end up burdening the most vulnerable segment of society. Whereas other aspects of the CTBCM will take us towards making compromises on strategic projects and benefits in areas of natural interest, while giving incentives to market participants in the name of fostering competition.	5	95
116.	*Arbitrage opportunities for some players* although mentioned, need to be documented and deliberated upon in detail, with identification of the concerned *players*. Such loopholes should	2	96

	not be left open on premise of being resolved at some later stage. Detailed scrutiny and analysis of this aspect is required.		
117.	Again appropriate procedures to properly account for energies traded at different time periods is left undefined to be developed at a later stage. With majority of the meters in Pakistan not equipped to handle such hourly trading this is a high risk activity for the management of the sector.	3	96
118.	With market prices changing hourly in the envisioned CTBCM the footnote 35 on page 96 seems to make a proposition which shall result in inaccurate calculations by *creating standardized load profiles to transform the energy consumed by end-customers in monthly basis to energies demanded in hourly basis.* Simply put imposing pre-decided consumption patterns on consumers.	footnote	96