Comments on Staff Paper "TRANSMISSION PLANNING, CONNECTIVITY, LONG / MEDIUM TERM OPEN ACCESS AND OTHER RELATED ISSUES"

General Observations on the subject and specific responses to the queries of the staff paper.

1. <u>Open Access and General Network Access in Transmission : Electricity Act 2003:</u>

Electricity Act 2003 stipulates "Non-discriminatory Open Access in Transmission and Distribution" in the country. Such "Open Access" in Transmission and Distribution was envisaged to enable the consumer to have freedom to choose his supplier which in turn would be determined by the price determined by market competition. However over the years, such a market is yet to evolve completely both in bulk and retail power sector.

Trading of electricity was identified for the first time in India through Electricity Act- 2003 as a distinct activity for development of Electricity Market. Thereafter Traders and Power Markets were introduced to transact bulk electricity across length and breadth of the country. Power Market transactions could not find enough carriage (transmission capacity) to meet all desired transactions resulting into market splits . The situation is otherwise called other than in the context of Power Markets as congestion. Market split has been highlighted as a major issue despite the fact that the quantum of electricity traded in Power Exchanges continues to be miniscule i.e. About 2 % and the denied transactions barely amounted to little over 15% of the total volume. It is pertinent to mention that it is not possible to make an unconstrained transmission system throughout the country to meet 100% power transfer requirement.

Inter State trade was expanded to cover transactions by one entity within one state to sell to or buy from another entity within another state through ISTS. Ideally, "Open Access" is a concept guaranteed by utility when it unbundles vertically to separate business segments amenable to competitive markets and those which are perpetually regulated monopolies. "Open Access" does not extend to neighbouring utilities system and resources. Some utilities by mutual agreement may choose to operate as tight power pools (e.g. PJM, USA) where "Open Access" may extend beyond a utilities boundary.

Country wide "Open Access" mandated by the Electricity Act 2003, has been sought to be reinforced as General Network Access (GNA). **However if it is applied across the country will demand huge transmission investments. To avoid a few days of "Market Splits" enormous idle investments will be made. The staff paper rightly dismisses the proposal.**

2. <u>Duration of Open Access:</u>

Open Access has been defined for three distinct duration Short (STOA), Medium (MTOA) and Long (LTOA, later changed to LTA). From para 1, Open Access by definition can not have a term attached to it. The moment, term of Access is defined, the same ceases to be open and changes to an Access which is 'sought and granted' one.

Access in ISTS in our opinion should continue to be sought and granted and hence should cease to be called Open Access. The point of injection into the ISTS, withdrawal from ISTS and the duration applied for, will have to be defined while seeking the access. Access to ISTS should be available to entities who have been granted connectivity with the ISTS. Those entities connected to the STU system shall only sell to the intra state customers and if any sale from such sources is to be sold outside the state **the sale should be by the state entity**. This process would remove the intra state transmission constraints because states will also develop their system based on the network requirement.

3. Electricity Trade Transaction and Transmission Access:

   Electricity Trade and Transmission Access are two independent transactions and no one-to-one correspondence is necessary between the two, as it exists presently. Electricity sold in long term, but for which there is no long term transmission access should be allowed to use short / medium term Access (not Open Access) to transfer the trade contents. There is no reason why such access must be denied. Similarly, somebody may seek long term access to transfer electricity traded in the short term. This also need not be prevented, so long as the parties are willing to pay.

   Further, presently all the electricity transactions under the Short Term (STOA) access, including Power Exchange transactions are treated necessarily as "Energy Transactions". This in our opinion is paradoxical. It has been long recognized that Electricity essentially consists of two de-coupled products (this has been the logical premises for favouring two part tariffs) viz. Capacity and Energy. All trade transactions in Electricity should, by the same logic, be as twin products of Capacity and Energy. Capacity trade is the right to use the facility and Energy trade is the actual use. This aspect has been well emphasized in the ECC report itself, which forms the essential corner stone of the ABT itself. In fact ECC report insisted that even UI transactions also must have two components, Capacity and Energy paid for separately.

   Accordingly, the Electricity transactions under STOA, in the initial period have been in two parts, Capacity and Energy. Capacity was committed for the entire duration of the trade where as energy was to be scheduled / rescheduled up to gate closure, currently 4 time blocks of 15 minutes each. This arrangement was sought to be changed to entirely Energy transactions under STOA by the RLDCs, as there was a perceived non-utilization of transmission capacity. This is incorrect as if by saying that spinning reserve capacity in the system amounts to non-utilization of generation capacity.

   The issue with the current prescription is that all STOA transactions are pre-scheduled as early as at the time of grant of STOA (up to 2 months ahead of the commencement of the access period which can be as long as 3 months) and in real time the buyer is under compulsion to draw this energy, even when far cheaper options are available to him. This negates economic use of energy as the drawing entity is compelled to look at the energy charge of the cheaper long term option as an additional cost. Had the STOA transaction also been Capacity and Energy separately charged, the comparison of the energy charge of either would have decided the scheduling. Thus for ensuring the perceived (that too wrongly, as brought out subsequently) utilization of transmission system, higher cost is forced on the drawing entity and overall economy of use of energy is negated. Now look at the reality of usage of transmission capacity. In real terms all electricity transactions are finally settled as UI (under Deviation Settlement). The energy transaction in reality need not be physically fulfilled at all!

"For example, imagine that Delhi has contracted 300MW power on 1st April for drawl for three months from June to August at a composite charge of Rs4/- per kWh from Odisha. Delhi is expecting a high demand of 4500MW (max) during the period. With this 300MW the capacity available to Delhi adds up to just 4500MW. In the month of August due to unseasonal and excessive rains the demand of Delhi is under 4000MW (max). Delhi has to draw the 300MW from Odisha and is prevented from drawing energy from Singrauli at Re1/- per kWh. Assuming that the variable Charge of Odisha is Rs2/- per kWh, Delhi and the country is spending Re1/- per kWh unnecessarily on account of this stipulation. In reality, neither Odisha needs to sent out the said 300MW power (in which case it will have to pay the UI/Deviation Charge for the energy not sent) nor Delhi has to draw the 300MW (Delhi will get paid for the quantum of reduced drawl as UI/Deviation Charge). In such a case, the transmission capacity would not be used.

Thus in our considered opinion, the staff paper and the subsequent regulations must address the STOA also along with the other variety of Access in consideration. Period of Electricity transaction and period of access must be de-linked and Electricity trade must be made in two parts, irrespective of duration. Power Exchanges should transact Capacity and Energy separately and energy should be treated as transacted only if scheduled, up to the day ahead. Intraday transactions can be in energy terms only.

4. Transmission Planning:

In India we do have a problem of segregating ISTS and State Transmission system (STS). This is a very tedious and impossible task. All transmission elements built for transfer of inter-state power , including from ISGS located within the boundaries of a state should also be considered as ISTS. Planning of such transmission elements by CTU, CEA and STU concerned will have to be jointly agreed.

STS must be planned by the respective STU considering Open Access to all Intra state constituents, considering all resources within the state and inter-state transmission landing points and corresponding quantum. STU must consider all generation capacity for which connection has been applied for, granted by the STU.

ISTS must be planned only for the capacity (with appropriate contingency margins) for which ISTS connectivity has been applied for and has been granted by the CTU, even when it is through another ISTS licensee. No generation facility shall be permitted to seek connectivity to both ISTS and STS .However, while finalising transmission system facilities by both ISTS and STS may be created, the connectivity being granted for ISTS only. Any connection to STS for ISTS connected facility and vice versa shall be based on an agreement between the CTU and the STU concerned. Such points of connection will also be treated as STS interface point with the ISTS and treated accordingly for all purposes.

For all planning purposes the ISTS and all the STS involved must be treated as one single transmission system and accordingly requirements must be decided, including contingency capacities.

The concept presented as GNA thus should be fully applicable to STS also, and Connectivity should decide the transmission capacity of ISTS. All ISTS connections must indicate the points of injection and drawl and the corresponding quantum. Any change subsequently may be allowed at the discretion of the CTU/CEA and incremental charges must apply.

5. Issue of LTA Quantum

LTA application should be limited maximum up to Installed capacity minus auxiliary power consumption as continuous operation of generator shall be at its rated capacity minus aux. consumption. As per grid code, generator may be asked to support grid at 5% higher capacity for a limited period. The transmission systems are planned under N-1-1 contingency criteria, there is always a sufficient margin for 5% whenever required. This requirement of 5% also may be relooked into after commission of National Grid by modifying the Grid Code. There is very increased Stability at present. **Therefore the generator ought to restrict their LTA up to the installed capacity minus Auxiliary Power requirement to enable them to utilize the margins created by transmission planning Criteria for Intermittent Grid Requirements.**

6. Quantification of Risk for transmission business

Among the different activities of the power sector value chain, transmission business enjoys lower risk as compared with other areas such as generation or distribution. As compared with the thermal power generation business, transmission business has almost no operational risk. For example, a thermal generation unit has to arrange various inputs such as coal/ gas/ oil, water etc on a daily basis to operate the units economically. The risk of any disruption in the availability of these inputs is borne by the generator. The transmission licensee does not have face such kinds of risks. Besides a thermal power generating unit has to face other risks in the form of stricter environmental norms and ash utilization/ disposal challenges, which are absent for a transmission licensee. Further, about 40000 moving components of different sizes are required to run in synchronism to produce electricity, besides utilisation of the capacity of a generating station to a high level on a continuous basis.
On the other, the transmission systems do not require any significant operational effort on daily basis in the form of arranging any raw material such as coal, oil, water .No challenges are faced in regard to disposal of process waste such as ash disposal and environmental management. In addition, 99% of transmission system components are static in nature.
Even during the project execution phase, the risks are more for the thermal power generators as compared to the developers of transmission lines/ substations considering the complexity of issues involved in the construction of a power plant. Construction of thermal power generation units entails involvement of more no. of specialized equipments, engagement of more number of contractors/ agencies which makes it difficult to complete the projects on time. Similarly considering the amount of land required for a thermal generation unit as compared to the transmission lines/ sub-stations, land acquisition is a greater challenge for the thermal power generating units. Besides, the gestation period of a transmission project is very low(to the order of 35-40% as compared to generation project).This means that for the same rate of return, a transmission project in spite of encountering far lower risk would generate significant high IRR as compared to thermal generating plant.

In spite of this, transmission tariff in the country, has been growing at a higher rate as compared to the tariff of the thermal generating stations. It can be seen that the Transmission tariff has grown at a CAGR of around 16% during the period from 2009-10 to 2013-14. In comparison, the Fixed Charge component has shown an increase of only 10% during this period for thermal power plant.

It is also noteworthy that in Indian context, the principal investors in transmission (CTU at National level and STU at State level) also happen to be among the transmission planners in their respective domain which naturally inculcates the tendency to over plan and overinvest disregarding optimal utilization of assets so created. There is a need to assess the uses of transmission assets in terms of their loading levels and contribution to grid security and stability. Further the staff paper also envisages various types of risk hedging measures such as 100% BG etc, investment servicing even before commencement of Generation and utilization of transmission assets and seeks to over protect transmission segment at the cost of other segments of power sector. This would be discriminatory and detrimental to Power Sector.

Under the Rate of Return regulation regime, the tariff should reflect the risk and the riskier business should be given higher return. Considering the above aspects, the return to transmission assets should be benchmarked and return to other sectors such as generation should be allowed with a premium commensurate with associated risk.

7. Other Issues

In order to address various issues raised by POSOCO, CTU regarding leaning of generator on existing system without LTA and endangering grid security, a process can be evolved with clear guidelines for not allowing injection for sale of power indefinitely with mere connectivity granted.

After specified period of connectivity sought for unit commissioning activities, connectivity should be considered automatically lapsed until unless further approval is sought with supporting reasons for such extension. The connectivity application process should comprise of an undertaking for filing of LTA mentioning that connectivity is for sole purpose of unit commissioning activities only. The connectivity regulation should also have provision that in any case physical inter-connection for connectivity shall be allowed only after completion of LTA.

Further in case of new transmission system addition, permission for implementation of transmission system should be given only in case of completion of LTA application process.

There should not be any loading of cost on Generation developer beyond the switchyard level as all existing PPAs are signed on ex-bus basis and it will make system more difficult and complex if dedicated line’s cost are being funded/part funded by the Generating company as the system configuration is very dynamic in nature and continuous configuration changes happen by way of LILOs, series compensation etc.

Response to the queries in the staff paper:

QUESTION NO.1 Whether Connectivity should be retained as a separate product:

(A) Yes (B) No

Answer: Yes. Connectivity should also quantify the capacity of the facility connected and transmission capacity creation can be staggered.

Question No. 2(a)

If Yes, what are in your opinion are the advantages of Connectivity as a separate product?

Answer:

Advantage of a separate product

The connectivity details provide the basic technical input data to generating utility like voltage level of step up switchyard, fault level, no. of bays etc. required for planning at the initial stage in Generating Switchyard. It helps in early finalization of specifications for major equipment/systems like Switchyard and Power Transformer Package.

The time frame required for providing physical connectivity and creation of evacuation system as per LTA are different particularly for green field project and the difference between providing physical Connectivity and LTA could be 21 months (15 months before synchronization for start-up/commissioning activities + 6 months for COD).

In case of brown field projects, the provision of physical connectivity may be from electrical system of existing generating station without any connectivity line/ additional system requirement. Subsequently, Transmission system augmentation if required can be taken up for power evacuation as per LTA granted. Hence these two activities are actualized under different time frame.

Considering above, Connectivity & LTA should be kept as separate application as per present provisions.

Question No. 2(b)

If connectivity is retained as a separate product, then what whether is should be free or transmission charges should be borne by generator or drawee entity which is applying for connectivity?

Answer: **The connectivity should be free for a Generator** because the same lines would be used for power evacuation at a later stage and would become part of ISTS.In any case for a green field project, whenever a transmission line is required to be ready in advance for Start-up power requirement. The transmission charges for such lines (i.e. for connectivity portion) are being paid till the CoD of Unit based on the tariff determined by CERC. Further in case of brown field projects, since the readiness of any line for start-up power requirement need not be advanced, the issue of connectivity charges does not arise.

Question No. 2(c)

Whether for connectivity, only transmission charges corresponding to connectivity transmission system should be charged or some part of Grid transmission charges (25% as proposed) should also be charged?

In case of a transmission line which has been advanced for start-up power requirement, only interest on loan and O&M expenses should be payable. **Therefore only 25% charges should be payable for the transmission line made for the purpose of stat-up power**.

Question No. 3:

If no, what is in your opinion are the dis- advantages of Connectivity as a separate product?

Answer: Not applicable.

Question No. 4: Bank Guarantee

What should be amount of sufficient construction bank guarantee to safe guard against the risk of stranded asset in case generating project fails to get commissioned?

(a) Is existing construction bank guarantee amount (Rs 5 lakh per MW) sufficient when transmission cost is about Rs 1 cr per MW.?

Answer: In CERC (Grant of connection, Long-term Access and Medium term open Access in the ISTS and related matters) Regulations, Bank guarantee for following condition is not applicable:

Quote"

In case of applicants who have already firmed up the entity or entities to whom electricity is proposed to be supplied or from whom electricity is proposed to be procured for the entire quantum of power for which LTA has been sought through signing of PPA or, in the case of Inter-State Generating Stations owned by the Central Government or Ultra Mega Power Projects coming up through the initiative of the Central Government, allocation of power to various beneficiaries as notified by it, then the applicant shall not be required to submit Bank Guarantee(BG) with the application form or the Construction stage BG. In such cases, however, the augmentation of the transmission system as identified for grant of LTA shall be undertaken only after agreement of the beneficiaries in Standing Committee on Power System Planning/Regional Power Committee for bearing the transmission charges -------

"***Unquote***

The Bank guarantee requirement as per existing Regulations may be retained for the projects cited in the above quoted Regulation.

In other cases where either PPA is not available for the LTA quantum or allocation from MOP/ GOI is not there following are observations;

- If dedicated transmission system is planned for Generator up to the pooling point Bank guarantee of Rs. 5lakh/MW may be considered in case of stranded asset.
- In case of deep connection, if system don't fall under the category of dedicated corridor and planned as composite corridors/transmission systems, the BG amount should be only proportionate to individual generator MW capacity even in case of single generator as same can also be utilized by other generator or by existing users and power will flow as per law of physics.

Q4 (b) Is proposed bank guarantees equivalent to cost of transmission line is sufficient?

Answer: The transmission system associated with any generating station contains two parts
i) Dedicated lines up to a pooling substation
ii) System strengthening requirements beyond pooling points

If generating station gets delayed, only dedicated portion of line gets affected and not all. So considering cost of Rs. 1cr/Ckt Km which would be carrying power of approx... 700MW translated to max. construction cost of Rs. 14lakh/MW (Considering Quad line of 100kM).so therefore 5lakh/MW BG which is approximately 35% of the cost, seems to be more than sufficient. We agree that in case of exit, only cost apportioned to dedicated portion should be compensated in proportion to MW withdrawn. Ultimately, the asset shall be utilized for other customers by LILO etc. or can be auctioned to States/other utilities by modifying the ckt configurations.

Q4 c) Is The proposed BG are very high?

Answer : The proposed BG is very high and will deter the investment in generation besides diversion of business risk from Transmission segment to other segment of power sector.

An assured return of 15.5% with low gestation period to transmission utilities which requires very minimal effort for earning this return post commissioning encourages the transmission utility to erect their assets without paying any attention to the corresponding development in the generation project which is far more cumbersome & time consuming as compared to a transmission project. This would incentivize a situation in which transmission assets are constructed without matching the commissioning of generation capacity after grant of LTA.

Question No. 5: Bank Guarantee

What should be amount of sufficient construction bank guarantee to safe guard against the risk of stranded asset or transfer of liability to other consumer in case generating project wants to exit/ downscale LTA after commissioning (Please give justification for your views)

(a) NPV equivalent to 12 year transmission charges

(b) NPV equivalent to 7 year transmission charges

(c) X Rs per MW of installed capacity –One time charge

(d) Five years Average Injection and withdrawal charges

(e) Five years Average injection charges only

Answer: This question needs careful consideration. If the exit happens after the facility has been established, the successor owner of the facility will be obliged to service the charges, and use the access. If the generator exit before the facility is established, the exit charges must only be a part of the servicing charges for 5 years or so till the system will be used by other users. Ideally this should be covered in the connection & Access agreement. The cost of any element created exclusively for the facility's connection (For connectivity purpose only) and which cannot be used by any others must be fully covered. This should be determined on a case to case basis.

Question No. 6: Delay in Commissioning

(a) Date of LTA should be firm and no relaxation should be provided

Answer: In case of delay in generating unit(s) /project:

To be covered best in the PPA and/or connectivity/access agreement. Further, charges allowed must be limited to interest on loan and any other incidental cost should be allowed to be recovered if the transmission system has been established and cost incurred, less usage by any other user. Normal transmission tariff should be permitted only on CoD of a Generating Station or else it should be left according to agreements entered between a transmission licensee and Generating Utility e.g. The Indemnification agreement entered between CTU & NTPC provides for IDC up to 6 month to be payable by NTPC in case of delay of Generating Station & Powergrid would pay 35% of IDC up to 6month in case of delay of a transmission line. However the transmission developer also need to be charged if generating plants get commissioned before transmission system.

(b)If information of delay is provided sufficiently in advance some staggered relief can be granted?

This option can be considered only if the transmission project can also be delayed. This will have to be determined on a case to case basis. The total transmission system can be awarded in two parts i.e. Transmission system required for start-up power and rest of the transmission system linked with award of any critical mile stone (critical off-site areas such as CW/make-up water etc.) or to be mutually agreed award date between Generator and transmission.

(c)Issue should be decided mutually between generating company and transmission licensee subject to condition that no burden is transferred to other users .?

There are a lots of difference with respect to difficulties and complexities of a Generation project vis a vis transmission line project. A generating company has to face huge land acquisitions issues and about 40 packages are to be executed round the clock. Besides more than **20** clearances are required before the project execution.

This will not be reasonable. The transmission system will eventually find use and the entire cost on the generator which could not establish the facility being made to commit stiff penalties will be huge deterrent. This will cause drying up of investment in generating capacity addition.

As per the present policy, the Transmission systems are in general implemented through Tariff Based Competitive Bidding process unless exemptions are approved by appropriate authority. The implementation schedule for the transmission system undertaken through TBCB, includes all the associated activities i.e. obtaining the transmission license, Section-68, Section-164, Right of Way (ROW), forest clearance, land acquisition for pooling substation (if applicable) etc.

In case of delay in any of the associated activities/ statutory clearances, land acquisition, the transmission system implementation schedule gets affected and may lead to contractual/litigation issues. Transmission system implementation linked to generating project through TBCB is undertaken after award of Main plant/EPC package of the project. The award of generating plant is done after completing all issues like MOEF clearance, Land, coal, water etc.

In view of above, there could be issues of delay from transmission system as well due to land acquisitions and other clearances i.e. forest & ROW. In order to ensure transmission system matching with generating project, there is need to co-ordinate between generator and Transmission system licensee and match their schedules as per requirement.
Present transmission system bidding document don't have provision for such mid-course actions/ adjustment. As experienced in recent past due to land acquisition/forest clearances transmission projects linked to generation projects have been delayed considerably. Vindhychal pooling point is latest example for reference.

In such situation, since there is no mechanism for adjustment, implementation of contingency arrangement involving available existing nearby transmission system through TBCB may not be possible in the specified time frame and generator suffers huge financial loss.

Presently there is no arrangement to compensate generator on account of delay in transmission system. In our opinion such adjustment/modification in transmission system would be possible in cost plus mechanism through Power Grid. In view of above, there is a need for close co-ordination & adjustments in schedules as per matching requirements of generation and transmission systems which should be taken up by POWERGRID under cost plus mechanism. Honourable commission is requested to review this aspect for implementation of transmission system linked with generating station under cost plus mechanism through Power Grid especially for Central Sector PSUs.

LTA date is the date of availability of transmission system. Hence in any case as issues could be from both generation and Transmission side for matching the project requirements, the information of revision in schedule should be available to both the parties. Hence if PPA for the project is available the common transmission system even constructed before project commissioning would be used by the regional beneficiaries as part of regional system, hence no charges should be applicable to generator. In case of dedicated lines if not used as part of system, matching of schedules would be co-ordinated and for the mismatch period issue could be addressed as per prevailing CERC regulations/agreements between the parties

The delay portion to be agreed mutually between generating company and transmission licensee in such a manner so that in case Gen station is getting delayed, the dedicated portion of Line is also staggered/delayed.

The staggered relief may be provided. Further bi-annually meetings should take place between Generator developer & Transmission licensee to match the commissioning schedule.

Question No. 7: Shallow Connection vs Deep Connection:

(a) What is your view on shallow connection vs deep connection?

(b) Shallow connection should be permitted to only renewable generation or to both Renewable and conventional generators. ?

(c) Under shallow connection system how transmission planning will be done and who shall bear the Grid level transmission charges?

The majority of the countries are following shallow connection system. In Indian scenario, the connections are 50% shallow+50% deep type. The PPAs in the entire country are generally at ex-bus from the Generating Switchyard so it should not be disturbed. However since many RE projects are coming-up, a shallow connection policy may be introduced subjected to certain conditions .e.g. for RE project capacity less than 250 MW, only lines up to 33kV up to a pooling point shall be in scope of RE Project .Howver any system 33kV and above must be done by Central/State Transmission Utility as the case may be. Besides in case of Central Generating station, whenever any RE project required to be set-up , it should be allowed to be integrated with existing electrical system of the plant at any voltage level.

It should be obligatory on the part of transmission licensee to avoid such mismatch since a transmission project is incidental to Generation project and not the vice-versa. There is an urgent need of segregation of transmission charges under RE projects and cost of transmission system augmentation system should be met by revenues generated from (Congestion, Power exchanges, STOA/MTOA transactions) PSDF fund as the margins created for RE projects shall be utilized by Power exchanges/STOA transactions when RE projects are not in service. Further the cost of transmission system up-dation for RE projects may be collected through application of RE cess on STOA/Power exchange regulations.

Shallow connection should be permitted to both renewable and conventional generators as it helps in connectivity (it is required 16 months prior to synchronization for start-up activities) of generator to ISTS. However, in case of conventional generator, connectivity is a technical requirement limited to start-up and commissioning requirement and LTA commitment is necessary to avoid leaning on to system and grid security aspect. Accordingly, deep connection would facilitate for individual generator power evacuation.

Question No. 8:

a. Whether you are a injecting entity or Drawee entity or both?

Question No. 9: GNA

a. What is your opinion on General Network Access (GNA) proposed by CEA ?

b. Whether it should be adopted for transmission access and transmission charges

What should be bank guarantees and Exit Charges under GNA mechanism?

d. Whether it would be possible to plan transmission system to give assured access in all directions?

Ans-8 NTPC is mostly injecting/sometimes drawing.

Ans-9 GNA proposed by CEA has following issues:

A) It does not include the State Network Access.

B)It is not clear how the system strengthening will take place.

C)It will call for new pricing methodology and new regulations

D)GNA is only for generators. It is not open to Bulk consumers.

Issue of segregation where LTA quantum is very less comparison to installed capacity. CTU should include all networks data up-to 132kV to fine tune the system requirement.

In an ideal condition, GNA concept would give complete flexibility to both generators and drawing entities. However, the transmission planning with GNA concept would be quite challenging in order to accommodate flexibility in injection and drawal anywhere in the grid. This is similar to concept that highways are built as an infrastructure and users pay subsequently based on their use. However, as brought out by CERC, declaration of GNA requirement in advance by all STU may not be actual and they tend to declare less which may lead to again congestion scenario.

QuestionNo.10: Transmission Planning:
How Transmission planning in the country needs to be reviewed under present condition to take care of future need of robust transmission system?

In line with NEP "Prior agreement with beneficiaries would not be a pre-condition for network expansion. CTU/STU should undertake network expansion after identifying requirements in consultations with stakeholders and taking up the execution after due regulatory approvals."

At present, NEP and regulations are not aligned because of necessity of LTA/BPTA agreements with beneficiaries.

The policy of NEP to be strictly adhered.

CTU to be 100% independent from PGCIL.

Fixed time line needs to be defined for implementation of each activity e.g.

Each network expansion (400kV and above) to be approved by CERC/SERC. Need of signing LTA/BPTA to be abolished for faster execution of Network expansion and utilization index of each transmission lines to be defined in line with PLf. E.g. if a line can carry max 500MW, what is the normal loading over a period of time. The study should be focussed in such a manner so that existing assets already created are being used to at-least 60-70%.Further for any new grid sub-station to be set-up, downstream system should also be planned and its award should be placed within a gap of 2-3 months after award of grid-substation to avoid mismatch and creation of stranded assets for which CTU to co-ordinate with concerned states.

India is a country with vast diversity in climatic condition, growth, natural resources etc., the transmission planning need to be planned taking into account the generation centre (pockets where coal, water or renewable conditions are available) and load center (taking into account urbanization and industrial set up) as already been laid in planning criteria. Since the transmission system of CTU is developed for state transmission system and transmission system developed by state transmission system is for DISCOMs/beneficiaries, there should be close coordination of transmission system developed by both entities as absence of either system will not help in power evacuation and ultimate user may not get the benefit. Mechanism should be evolved to make STU and ISTS systems seamless in order to optimize the overall cost of system in the benefit of ultimate user. There is a need to evolve a mechanism of use of ISTS and STU systems optimally by evolving transmission charge sharing mechanism in order to avoid redundant systems put up by STU and ISTS.

Q 10 b) whether there is need for a separate Regulation for transmission planning to make it more participative?

In a country like India, where whims and fancy of States matter a lot, if a regulation on transmission planning is introduced, it will be a better option because of regulatory compliance.

Q 10c. Whether transmission planning should mandatorily make margins available for short term power market?

As the name implies, short term power is for short duration to feed any demand supply gap in power market. As per the transmission planning criteria depending upon voltage level, transmission systems are being developed considering N-1 & N-2 criteria. Hence the margins available owing to the above transmission planning criteria can be used for short term power market considering that maximum power demands are met through LTA. Major transaction through LTA is desirable for stable grid scenario and development of robust transmission system. As the entire transmission system development is primarily on the cost of Long term customer, for stable grid condition and congestion free system short term charges should not be so low that it attracts players to leave long-term and adopt short term transactions.

Q10 d. Whether transmission system planned by CEA /CTU need to be adequately explained from cost benefit point of view?

Transmission system developed by CTU & STU are required to be closely coordinated to make power available to end user i.e. consumers. As the ultimate cost is paid by the consumers, the planning of transmission system developed by CTU and STU to be analyzed and explained from cost of point of view so that unnecessarily padding of transmission cost is not there due to duplicity in transmission system by both CTU and STU. Also in the present scenario, getting right of way for transmission is more and more difficult, hence it is more important to have coordinated transmission planning by CTU /STU/CEA.

Q 10 e. Is there requirement of making submission of information related to transmission planning legally binding .?

Since transmission planning is a continuous process, only data/ information sought before actually execution of network expansion to be legally binding.

Whether transmission planning should mandatorily make margins available for short term power market?

Depending on volume of transactions and constraints faced by short term markets in last 3-4 years, min 5% margin may be kept in400kv networks.

Question No. 11: Utilization of Congestion charges

(a) Whether proposal of using congestion charges to reduce the long term ISTS transmission charges acceptable? Or

Unconstrained transmission system is impossible to build. ISTS particularly must be built for limited anticipated exchange only and constraints will hence be associated with system outages. Control mechanism of power exchange among control areas rather than congestion charges to indirectly control power exchanges is the right approach. Many of our control areas have no control capability. E.g. Goa, Delhi, Bihar, Puducherry etc. Ideally they should merge in the control area of nearest big brother. For example Delhi could merge in UP area where UP assumes the control obligations of Delhi. In return UP gets the surplus capacity available with Delhi. In some cases a consideration may also be agreed.

It is still better, if larger control areas can be created by agreeing to operate as tight power pools. Natural pools exist in the form of Regional power systems, within which Open Access (GNA) can also be applied. Control area obligations of frequency control contribution and net exchange control will then apply among 5 regional Power Pools only. The country will thus have 5 major control areas. More sub-areas within these control areas W1/S2/W3 or S1/S2 can also be considered. This would mean centralized dispatch in each region, i.e. “Option-A” market mechanism suggested mentioned in the ECC report, which had been the option insisted by NTPC during implementation of ABT

(b) Whether Congestion charges are to be utilized for creation of specific transmission assets for relieving the congestion? How should this be treated- as equity, loan or grant?

Congestion is a natural and unavoidable phenomenon. It should be managed by scheduling and control and not by applying charges.

Question No.12:

Transmission corridor allocation for Power market:

a. Whether participants of Power exchanges should be allowed to participate in e-bidding for transmission corridor? or

Under the arrangement of Control Areas described earlier, each control area will be a separate bidding area and all transactions will be within control areas where Open Access/GNA is applicable.

The proposal to allocate advance corridor to collective transactions by e bidding or by cost borne by all participants of power exchange will further decrease the corridor for bilateral transactions and may lead to their extinction.

b.) For power market development, certain quantum of corridor may be reserved for power market with all participant of Power Exchange sharing the transmission charges of reserved corridor.?

Answer: This will be improper as described above. There should not be any reservation of Power corridor for effective and competitive development of Power Market.