

CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Subject: THE REPORT OF THE COMMITTEE TO REVIEW TRANSMISSION PLANNING, CONNECTIVITY, LONG TERM ACCESS, MEDIUM TERM OPEN ACCESS AND OTHER RELATED MATTERS

The Commission had constituted a Committee under the Chairmanship of Shri Mata Prasad, Power System Expert with the terms of reference to “study Staff Paper on Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues, to analyze the comments received in response to the above Staff Paper and to suggest an appropriate regulatory intervention with a draft regulation”.

2. The Committee has submitted the report to the Commission. The report is posted on the website for information of the stakeholders.

3. The Commission has not examined the report of the Committee including the recommendations, opinion and views expressed therein. The Commission will consider the report while making the regulation on connectivity and access to inter-State transmission of electricity.

Sd/-
(Shubha Sarma)
Secretary
30.9.2016

**Report of the Committee to
Review Transmission
Planning, Connectivity, Long
Term Access, Medium Term
Open Access and other
related issues**

September, 2016



**Central Electricity Regulatory Commission
36, Janpath, Chanderlok Building
New Delhi - 110001**



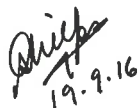
Committee to Review Transmission Planning, Connectivity, Long Term Access, Medium term Open Access and Other related issues

Foreword

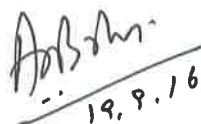
The Commission vide office order dated 8.12.2015 formed a Committee to “Review Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues under the chairmanship of Shri Mata Prasad with Shri Rakesh Nath and Shri A. S. Bakshi, Member, CERC, as Members and Ms. Shilpa Agarwal as Nodal Officer. The Terms of Reference (ToR) were *interalia* to study Staff Paper on Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues, to analyze the comments received in response to the above Staff paper and to suggest an appropriate regulatory intervention with a draft regulation.

The Committee held widespread consultations with the stakeholders, MoP, some power system experts and statutory bodies like CEA, CTU and POSOCO.

The Committee has finalised its report after considering the issues raised by stakeholders and their suggestions and hereby submits its report on “Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues” to the Commission. The Committee has decided not to prepare draft Regulations as per the Terms of Reference as it has recommended considerable changes in the transmission planning and terms and conditions of Connectivity and Long Term Access, Medium Term Open Access and Short Term Open Access and feels that the same may be accepted by the Commission, in principle, before an exercise is taken up for preparing the draft Regulations.



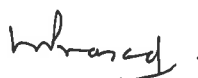
(Shilpa Agarwal)
Dy. Chief (Engg.)
CERC



(A. S. Bakshi)
Member
CERC



(Rakesh Nath)
Former Member,
APTEL



(Mata Prasad)
Power System Expert &
Chairman of the Committee

Constitution of the Technical Committee

1. Shri Mata Prasad, Power System Expert- Chairman
2. Shri Rakesh Nath, Former Member, APTEL- Member
3. Shri A.S. Bakshi, Member, CERC- Member
4. Ms. Shilpa Agarwal, Dy. Chief (Engg.),CERC-Nodal Officer

Special Invitee:

1. Shri A. K. Saxena, Former Chief (Engg.),CERC

Invitees:

1. Shri S. D. Dubey, Chairperson, CEA
2. Shri V. J. Talwar, Former Member, APTEL
3. Ms. Jyoti Arora, Joint Secretary, MoP
4. Shri Ravinder, Former Chairperson CEA and Power System Expert
5. Shri S.K. Soonee, CEO, POSOCO
6. Ms. Seema Gupta, COO ,CTU
7. Shri. A. K. Khurana, Association of Power Producers (APP)
8. Shri Pardeep Jindal, Chief Engineer, CEA
9. Shri Ghanshyam Prasad, Director, MoP
10. Shri. A.K. Asthana, Power Sector Expert
11. Prof. A. K. Tripathy, Former DG, CPRI
12. Shri. Deepak Amitabh, CMD, PTC India Ltd
13. Dr. K. Balaraman, Head, Power System, PRDC, Bangalore
14. Representatives from APTRANSCO, Bihar- BSPHCL & NBPDC, DVC, Delhi-DTL, SLDC, BYPL & TPDDL, Rajasthan-RUVNL, RVPNL, RDPPL & RDPPC, JUSNL, Karnataka- KPTCL & PCKL, KSEBL, Meghalaya Power TCL, Maharashtra STU, GRIDCO, GETCO, TSTRANSCO, West Bengal- WBSETCL & WBSEDCL
15. Representatives of RPCs

Acknowledgement

The Committee would like to place on record its appreciation for the detailed inputs provided by CTU, CEA, MoP and the Power System Experts in regard to current issues being faced in regards to planning and implementation of ISTS and suggestions for improvement. The Committee would like to place special thanks to Shri A.K. Saxena, Former Chief (Engg.), CERC, Shri. S.C. Shrivastava, Chief (Engg.), CERC, Shri Akhil Kumar Gupta, CERC, Shri Agam Kumar, Research Associate, CERC for their valuable inputs. The Committee acknowledges painstaking efforts made by the CERC officers in collating, compiling and drafting the report from the inputs and voluminous material available from various sources.

List of Acronyms

APTEL	Appellate Tribunal of Electricity
APTRANSCO	Transmission Corporation of Andhra Pradesh
ARR	Annual Revenue Requirement
BG	Bank Guarantee
BPTA	Bulk Power Transmission Agreement
BSPHCL	Bihar State Power Holding Company Ltd
BYPL	BSEB Yamuna Power Ltd
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CPP	Captive Power Plant
CTU	Central Transmission Utility
DAM	Day Ahead Market
DIC	Designated ISTS Customer
DISCOM	Distribution Company
DTL	Delhi Transco Ltd
EHV	Extra High Voltage
EIA	Environmental Impact Assessment
EPS	Electrical Power Survey
FACTS	Flexible Alternating Current Transmission System
FCFS	First Come First Serve
FERC	Federal Electricity Regulatory Commission
GETCO	Gujarat Energy Transmission Corporation
GNA	General Access Network
GRIDCO	Grid Corporation of Odisha
HCPTC	High Capacity Power Transmission Corridors
HVDC	High Voltage Direct Current
IC	Installed Capacity
ICT	Inter Connecting Transformer
IDC	Interest During Construction
IEC	International Electrotechnical Commission
IEGC	Indian Electricity Grid Code
IEX	Indian Energy Exchange
IPP	Independent Power Producer
ISGS	Inter-State Generating Station
ISTS	Inter-state Transmission System
JUSNL	Jharkhand Urja Sancharan Nigam Ltd
KPTCL	Karnataka Power Transmission Company Ltd
LC	Letter of Credit
LILo	Loop In Loop Out

LoA	Letter of Award
LTA	Long Term Access
LTAA	Long Term Access Agreement
MoP	Ministry of Power
MTOA	Medium Term Open Access
NBPDCL	North Bihar Power Distribution Company Ltd
NEP	National Electricity Plan
NGC	National Grid Company, U.K.
NLDC	National Load Despatch Centre
NPV	Net Present Value
PCKL	Power Company of Karnataka Limited
PGCIL	Powergrid Corporation of India Limited
PLF	Plant Load Factor
PMU	Phasor Measurement Unit
PoC	Point of Connection
POSOCO	Power System Operation Corporation
PPA	Power Purchase Agreement
PSDF	Power System Development Fund
PSS	Power System Stabiliser
PTI	Power Technologies Incorporated
RE	Renewable Energy
RLDC	Regional Load Despatch Centre
RLNG	Regasified Liquefied Natural Gas
RoW	Right of Way
RPC	Regional Power Committee
RPO	Renewable Purchase Obligation
RSVC	Re-locatable Static VAR Compensator
SCM	Standing Committee Meeting
SERC	State Electricity Regulatory Commission
SLDC	State Load Despatch Centre
SPS	Special Protection System
STATCOM	Static Compensator
STOA	Short Term Open Access
STU	State Transmission Utility
SVC	Static VAR Compensator
TBCB	Tariff Based Competitive Bidding
ToR	Terms of Reference
TPDDL	Tata Power Delhi Distribution Limited
TSA	Transmission Service Agreement
TSTRANSCO	Transmission Corporation of Telangana Limited
UT	Union Territory

VC	Validation Committee
WBSEDCL	West Bengal State Electricity Distribution Company Ltd
WBSETCL	West Bengal State Electricity Transmission Company Ltd
WSCC	Western System Coordinating Council, USA

Table of Contents

Executive Summary	i
1 Chapter-1: Background	1
2 Chapter-2: Staff Paper	7
2.1 Introduction	7
2.2 Issues raised in the Staff Paper	7
2.2.1 Issues raised by Transmission Planning Agencies	7
2.2.2 Issues raised by System Operator	9
2.2.3 Issues raised by Generators	9
2.2.4 Issues raised by Users, Open Access Customers and Power Exchanges	11
2.3 Suggestions made by different stakeholders	11
2.3.1 Suggestions made by System Operator	11
2.3.2 Suggestions made by CEA	12
2.3.3 Suggestions made by CTU	12
2.4 Regulatory Mechanism for providing long term solution	13
2.4.1 Transmission Planning Philosophy	13
2.4.2 Bank Guarantee	20
2.4.3 Treatment of delay and exit	20
2.4.4 Other issues	21
2.4.5 Questionnaire for Stakeholders	21
3 Chapter-3: Summary of Comments/Suggestions by Stakeholders on Staff Paper	23
4 Chapter-4: Issues raised by Invitees and their suggestions	56
4.1 Introduction	56
4.2 Issues raised by Invitees	56
4.2.1 Issues raised by transmission Planners	56
4.2.2 Issues raised by System Operator	56
4.2.3 Issues highlighted by MoP	57
4.2.4 Issues raised by IPPs	57
4.2.5 Issues raised by DISCOMs, Open Access Customers, Power Exchanges	58
4.2.6 Issues raised by stakeholders in MoP meeting	59
4.2.7 Issues raised by Power System Experts	60
4.3 Suggestion made by the Invitees	62
4.3.1 Suggestions regarding Connectivity	62

4.3.2	Suggestions regarding Transmission Planning	64
4.3.3	Suggestions regarding Recovery/Sharing of Transmission Charges	76
4.3.4	Suggestions regarding integration of renewable sources of energy generation	83
4.3.5	Suggestions regarding Bank Guarantee	84
4.3.6	Suggestions regarding issues related to Exit Charges	86
4.3.7	Suggestions regarding import/export requirement and demand forecasting by States	88
4.3.8	Suggestions regarding non-completion of downstream system	94
4.3.9	Other Issues	96
5	Chapter-5: Background of Transmission Planning	98
5.1	Introduction	98
5.2	Transmission Planning process – historical perspective	99
5.3	Present Transmission Planning Process: LTA based planning	99
5.4	Change in Market Scenario and Customer Aspirations	103
6	Chapter-6: Analysis and Conclusions	106
6.1	Introduction	106
6.2	Transmission Planning	107
6.3	Proposed Transmission Planning Process	114
6.3.1	Principles of Transmission Planning	114
6.3.2	Central Repository of Generators	115
6.3.3	General Network Access by Generators	116
6.3.4	Planning of Transmission System & its Implementation	119
6.3.5	Availing Network Services for Transfer of Power under various Terms of PPA	124
6.4	Scheduling Mechanism for States	126
6.5	GNA Agreement	127
6.6	Curtailment of transactions after finalization of day ahead schedule	128
6.7	Mismatch between injection GNA and drawal GNA	128
6.8	Date of Operationalisation of GNA	130
6.9	Intimation regarding termination of PPA	132
6.10	Sharing of Transmission Charges under GNA	133
6.11	Transition between GNA and prevailing LTA Regulations	136
6.12	Suggestions in regard to the issues raised in the Staff Paper	138

6.12.1	Connectivity	138
6.12.2	Construction of Dedicated Line	141
6.12.3	Start date of Connectivity	143
6.12.4	Point of Commercial Metering	144
6.12.5	Connectivity/GNA by a Captive Power Plant	144
6.12.6	Application Fees	145
6.12.7	Access Bank Guarantee	147
6.12.8	Encashment /Discharge of Bank Guarantee	150
6.12.9	Charges in case of exit/downscale of GNA after commissioning	151
6.12.10	Treatment of delay in Transmission System/Generation Projects	152
6.12.11	Treatment of payment of charges in case of non-availability/delay in upstream /downstream system	153
6.12.12	Utilisation of Congestion Charges	156
6.12.13	Transmission Corridor Allocation for Power Markets	157
6.13	Technical aspects to be considered while Planning of ISTS	158
6.14	Other Issues in regard to ISTS	166
6.14.1	Sale of surplus power by States	166
6.14.2	Demand Forecasting by States	167
6.14.3	Formation of State Standing Committee	167
6.14.4	Formation of State Power Committee	167
6.14.5	Draft Regulations	168
	Annexure-I: CERC Order of Constitution of Committee	169
	Annexure-II: Process of GNA/ Connectivity	170
	Bibliography	171

Executive Summary

- (i) CERC (Grant of Connectivity, Long term Access, Medium term open access and other related matters) Regulations, 2010, notified in the year 2009, became effective from 1.1.2010. The market scenario since 2010 has undergone significant changes. The volume of short-term transactions has increased from 65.9 BUs in year 2009-10 to 115.23 BUs in year 2015-16 and the average prices of electricity transacted through traders in short term has come down from about Rs. 7.29/unit in year 2008-09 to Rs. 4.11/unit in year 2015-16. The price of electricity transacted through power exchange for the year 2015-16 is about Rs. 2.72/unit. The trend is likely to cause more participants shifting towards Short term transactions.
- (ii) A number of petitions have been filed by stakeholders on various issues affecting them, for example, relinquishment of LTA by the generators, change of target region where power is to be sold by the generators, generators taking only Connectivity and not applying for LTA and payment of transmission charges for dedicated lines, etc. After the passage of Open Access Regulations of 2004 and 2008, the transmission planning process came to be largely driven by the Long-Term Access to the Inter-State Transmission System (ISTS) sought predominantly by generators. There are a number of petitions and applications before CERC wherein the generators have sought relinquishment of LTA but at the

same time power is being evacuated by them under Short term Open Access (STOA)/ Medium Term Open Access (MTOA) markets. CTU has also stated that a few generators have taken only Connectivity and have been evacuating their power under MTOA/STOA for which no augmentation is carried out and is granted on margins available in the transmission system. As transmission planning is LTA based, this scenario is likely to lead to under building of transmission capacity, which may in-turn lead to congestion in ISTS.

- (iii) It is experienced from recent trends that the power procurement by power utilities has moved from long term contracts of about 25 years to shorter term contracts. Further, availability of National Grid facilitates transfer of power from available cheaper sources. This has opened up opportunities for economic despatch of stations. Many States are backing down their own generating stations or not scheduling power from costlier ISGS and buying power from other sources through MTOA/STOA. The present transmission planning process does not incorporate economic despatch principle.
- (iv) To address the emerging issues, CERC brought out a Staff Paper on Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues in September, 2014. Based on comments received on Staff Paper and extensive discussions held with the stakeholders

and power system experts during Committee meetings, recommendations of the Committee are as follows:

1. Central Repository of Generators

A number of IPPs have commissioned their generation plants in the 11th and 12th Plan which were not being monitored by the CEA and were not considered in the transmission planning by CEA and CTU. All new generation projects mandatorily be required to register themselves at Central repository to be maintained by CEA. Application for grant of Connectivity/General Network Access (GNA) from a generator should be considered by the CTU only after it has been registered with the Central Repository. Periodic update of status including intimation on achieving specified milestones needs to be provided by the new generating stations.

2. Transmission Planning

- (a) Transmission Planning is presently being done on the basis of Long Term Access (LTA) taken by ISGSs. This system has led to a number of difficulties for IPPs who were not able to enter into Long Term PPAs in the targeted Regions as many of the DISCOMs are not inviting Case-1 bids. There have been difficulties for the distribution licensees in procurement of cheaper power due to transmission constraints. In order to build a robust ISTS with adequate margin and flexibility to facilitate economic transactions, the Transmission Planning may be done on the basis of projected load of the States and

anticipated generation scenario based on economic principles of merit order operation.

- (b) The new generation projects that are intending to avail the transmission services from ISTS may be required to avail Injection General Network Access (GNA) from CTU which should not be less than Installed capacity less auxiliary consumption. An Applicant may seek phased GNA in accordance with the commissioning schedule of its units.
- (c) In case of captive power plants with co-located captive load, the CPP may have option to take Injection GNA corresponding to installed capacity less auxiliary consumption less the captive load. CPPs connected to the CTU will also have the option for applying for drawal GNA for meeting captive requirement under contingency of tripping of its captive power plant and for meeting start-up power requirement of CPP. In case of Generators supplying free power to home state, GNA may be sought for capacity less free power only if State makes its own arrangement for drawal of free power.
- (d) All withdrawal DICs should also seek seasonal GNA corresponding to their anticipated ISTS withdrawal /injection requirements. The projected seasonal maximum import/export requirement in respect of a State from ISTS will be provided by the State Transmission Utility (STU) 4 years prior for a period of 5 years to CTU. In case the projected requirement for import/export of power is not provided by a STU, CTU may in consultation with CEA and POSOCO assess the import/export requirement of the State

and upload the same on CTU's website for comments from stakeholders.

- (e) A Validation Committee comprising representatives of CTU and STUs should be set up under chairmanship of CEA to validate the projected import/export requirement from ISTS provided by States/ assessed by CTU considering the comments received from stakeholders on the uploaded data. Such Validation Committee may finally approve the projected requirement for import/export of power for each State which may be uploaded on website of CTU and should form the baseline for planning.
- (f) System studies should be carried out for various generation and load scenarios during peak, off-peak and other than peak/off-peak hours for different seasons considering low, moderate and high renewable capacity addition, scheduling of various generating stations which do not have any PPAs based on the merit order and GNA applied by the Generating Companies and the load projections of the States.
- (g) The variable cost of existing generating stations may be considered as available with CEA/Regulatory Commissions. CERC may notify escalation indices for pit head and non-pit head plants to be considered for estimating the variable cost for planning period. The estimated variable cost of new generating stations should be estimated by CTU in consultation with CEA and the generating stations based on likely source of fuel, normative heat rate as per CERC Regulations, variable charges of existing generating stations in a state based on pit head/non pit head stations. In case of

non-availability of data from CEA, variable charge data may be considered by CTU based on similar sized units and norms for heat rate/ specific oil consumption etc. as per CERC Regulations.

- (h) Probabilistic scenarios be developed considering varying import/export requirement of each state, which should depend on generation–dispatches and probabilities of load forecasts. These scenarios be declared upfront and options in various scenarios should be put up on website of CTU for comments/suggestions of stakeholders. CTU in consultation with CEA should prepare detailed procedure specifying scenarios to be considered.
- (i) CTU should approach the Commission for regulatory approval of new transmission assets in respect of ISTS within a month of its approval by Standing Committee on Power System Planning.
- (j) Based on these, and progress of implementation of generating stations, mid-course correction for transmission system to the extent possible should be made.
- (k) For Renewable Energy Sources (RES), the transmission system may be planned by CTU based on estimated capacity additions in perspective plan and Renewable Purchase Obligations (RPO) of each State.
- (l) In case of mismatch between Injection GNA and Withdrawal GNA, planning of transmission system should be done for Withdrawal GNA including margin of 20% over Withdrawal GNA duly factoring known tie ups of power.

- (m) While planning the transmission system, options of upgrading the existing ISTS in place of building new transmission lines such as increasing line loading through use of compensation, reconductoring, etc., for optimally utilising the existing assets should also be considered.

3. Availing network services under PPA

- (a) GNA may, by itself, not entitle any generating station to interchange any power with the grid till it signs a PPA and registers the same with CTU or sell power through power exchange.
- (b) CTU should develop an on-line portal for registration of PPA by a Generator/STU/DISCOM. CTU should consider all the registrations done in a month within twenty days of end of the month and confirm the scheduling priority for the Generator/Discom/bulk consumer by the end of next month. While confirming the scheduling priority under long term /medium term, CTU should give priority to long term PPAs over medium term PPAs and among PPAs of same category on pro-rata basis.
- (c) The aforesaid methodology for scheduling priority may be reviewed five years after implementation of GNA system based on the experience during the intervening years.

4. Date of Operationalisation of General Network Access

- (a) Operationalisation of GNA should commence from the date indicated in the letter of grant of GNA or from the availability of the identified transmission system, whichever is later and

the liability for payment of transmission charges should begin from this date subject to force majeure conditions or Change in Law as specified in Paragraph 6.8.6 of this Report.

- (b) In the cases where operationalisation of GNA is contingent upon commissioning of several transmission lines or systems and only some of the transmission lines or elements have been declared to be under commercial operation, GNA to the extent which can be operationalised without affecting the security and reliability of the Indian Grid, should be operationalised and the GNA customer should pay transmission charges for the quantum of GNA operationalised.
- (c) The Committee also suggests that inability of a GNA Applicant to generate/supply electricity would not absolve it from liability to pay transmission charges.

5. Sharing of Transmission Charges under GNA

- (a) Sharing should be done as per the present system in vogue as per CERC (Sharing of inter-state Transmission Charges and losses) Regulations 2010. The charges should be commensurate to usage of transmission system.
- (b) Drawal / injection from ISTS up to GNA quantum plus a margin of 20% would not attract any additional transmission charges. The additional transmission charges for drawal / injection from ISTS beyond 120% may be kept as 25% above normal charges.

6. Connectivity

- (a) Connectivity may continue to be a separate product and applied for a quantum of installed capacity less auxiliary consumption. In case of captive power plants connectivity may be applied for a quantum of capacity proposed to be connected to ISTS. An Applicant would be eligible to apply for Connectivity only after it registers itself with Central Repository at CEA.
- (b) CTU may grant the Connectivity to the Applicant but Applicant should not be allowed physical connection with the grid before filing the application for GNA and furnishing construction bank guarantee thereof. Application seeking GNA has to be filed within 2.5 years of date of grant of Connectivity by CTU, failing which Connectivity granted should be withdrawn and application fees should be forfeited.
- (c) An Applicant should be charged with Reliability charges for connected quantum. For situations when generator is connected to ISTS for purpose of start-up power/injection of infirm power before operationalization of GNA, Reliability charges should be levied from synchronization of unit till operationalization of GNA corresponding to the installed capacity of synchronized units less auxiliary power.

7. Construction of Dedicated Line

- (a) Dedicated lines should be the responsibility of a generator since it can match the commissioning of such line with its generating station. An Applicant should be required to construct a Dedicated Line(s) to the point(s) of connection to

enable connectivity to the grid. In case CTU envisages dedicated lines as lines required to enhance the system reliability even if generation project does not come up or is delayed, CTU may consider such lines under coordinated transmission planning.

- (b) If a generator gets connected to dedicated line of another generator, then such dedicated line may be considered as ISTS after obtaining transmission license on filing application with the Commission under CERC (Transmission License) Regulations.
- (c) A generator should be allowed startup power only through dedicated line. However, in exceptional cases CTU, in consultation with RLDC/NLDC/CEA, may consider drawal of startup power through LILO of existing lines.
- (d) Although Connectivity lines are under the scope of generator, metering should be at the bus bar of the generating station. The same provision of metering at bus bar of generating stations should be made applicable even for the existing generating stations where dedicated lines have been constructed by generating stations to bring parity between new and existing generating stations.
- (e) Application fees may vary from Rs. 4 lac-18 lac for application for Connectivity and GNA as detailed in Chapter-6. Application fees shouldn't be levied on STUs.

8. Bank guarantee

Construction bank guarantee which is Rs. 5 lac/MW shall be named as Access bank guarantee and should be considered

as Rs. 20 lac/MW. After operationalization of GNA, Access BG equivalent to 1/5th of amount should be returned back to the Applicant till 4th year. The amount equivalent to 1/5th of Access BG should be kept subsisting till the end of 12th year as security towards relinquishment charges.

9. Charges in case of exit/ downscale GNA after commissioning

- (a) Any downscaling of GNA should not be allowed. In case a generator wishes to exit from GNA it should be disconnected from the grid. If a GNA Customer abandons the generation project or relinquishes GNA at any stage after placement of LOA or order to a successful bidder under TBCB route by Bid Process Coordinator or placement of LOA on contractor by POWERGRID, either partly or fully, for transmission system associated with that GNA to be developed by POWERGRID on nomination basis , the construction phase bank guarantee subsisting may be encashed. In addition, the generator should be liable to pay transmission charges for one year (as per prevailing POC rate for the generator in case rate is available for the generator, else all India average POC rate) towards exit charges. In case it exits 5 years post operationalization of GNA the generator should be liable to pay transmission charges for one year (as per prevailing POC rate for the generator in case rate is available for the generator, else all India average POC rate) towards exit charges. However, in case there are pending applications for GNA seeking the same corridor, exit charges may not be

leviable on the generator to the extent corridor is reallocated to other seekers.

- (b) A generator may derate its units due to technical issues in which case it should be allowed downscaling of GNA without any charges.

10. Treatment of delay in Transmission system /Generation projects

- (a) In case of adverse progress of individual generating unit(s) / expected delay of generators assessed during coordination meeting, CTU should endeavor to re-plan the system if the augmentation system has not been awarded already. In case the augmentation system has already been awarded and generator seeks deferment of start of GNA, no such deferment should be granted and the generator should be liable to pay full transmission charges from the date of operationalization of GNA.
- (b) In the event of delay in commissioning of concerned transmission system from its scheduled date, CTU should make alternate arrangement for dispatch of power at the cost of the transmission licensee. The interim arrangement so provided should be removed with commissioning of actual planned system.
- (c) In case such alternative arrangement cannot be provided, the transmission licensee should pay proportionate transmission charges as per its TSA, which should be provided to generator as compensation in case generator is ready and the concerned transmission system is not ready. Such payment

by the transmission licensee to generator may be recovered from the Contract Performance Guarantee furnished by the transmission licensee.

11. Treatment of payment of charges in case of non-availability/delay in upstream /downstream system.

- (a) ISTS licensee, CTU, STU, associated State transmission licensee and DISCOM should enter into indemnification agreement to agree upon payment of charges in case of delay by ISTS licensee/ State transmission licensee. In the absence of indemnification agreement, payment liability should fall on entity due to which an element is not put to use. For example, if transmission line is ready but terminal bays belonging to other licensees are not ready, the owner of terminal bays should pay the charges to owner of transmission line in the ratio of 50:50 till the bays are commissioned. In case bays on the one end are commissioned, the owner of bays at the other end should pay the entire transmission charges of the transmission line till its bays are commissioned.
- (b) Further CTU may coordinate with STU to ensure that ordering for intra-state transmission lines is done such that it is commissioned matching with ISTS lines. The ISTS should be included under POC calculations only after it is put to use.

12. Utilisation of congestion charges

CERC has notified Power System Development Fund (PSDF) Regulations in July, 2014. The congestion charges also form part of PSDF and are being utilized for various purposes (like transmission systems of strategic importance for relieving congestion, compensation devices for improving voltage profile, standard and special protection schemes, setting right discrepancies found in protection audit on regional basis, capacity building, technical studies, installation of PMUs, etc.). Accordingly, Congestion charges be utilised as per the said Regulations.

13. Transmission Corridor Allocation for power markets

Five percent (5%) of each flow gate may be reserved for day ahead collective transactions which may be released for contingency market in case of non-utilisation of the corridor by power exchanges. The percentage of reservation may be reviewed after one year of operation.

14. Sale of surplus power by STUs

A STU may seek injection GNA and Withdrawl GNA separately. Power in a State becomes available from its own generating stations and ISGSs in which it has share allocation . A State may like to sell power from its share allocation from ISGS. However currently there is no such provision through which a State may sell its share of power from an ISGS at injection point of ISGS. Necessary provision may be made that a State may be able to sell its share at

injection point of ISGS to avoid double charging of losses on such transactions currently in vogue.

15. Demand Forecasting by States

The essence of seeking GNA by STUs lies in accurate demand forecasting by them. CEA and CTU should handhold STUs for demand forecasting. STUs should procure software for short term/medium term and long term demand forecasting. The State Regulators may allow the expenditure towards procurement of software in their ARR. This work may be undertaken by the proposed State Power Committee.

16. Formation of State Power Committee

A State Power Committee similar to Regional Power Committee (RPC) may be established at State level to coordinate issues affecting state involving all stakeholders within States. Such a committee should coordinate between STU and DISCOMs for assessment of GNA and between SLDC and DISCOMs for demand/load forecasting.

17. Assessment of Available Transfer Capability for existing System

There is a need to assess the Available Transfer Capacity (ATC) of existing system through independent experts. Commission may entrust the task to third party for independent assessment of ATC for existing system and measures that can be employed to enhance the transfer capability of existing system through SVCs/STATCOMs, SPS, dynamic line rating etc.

18. Technical aspects to be considered while Planning of ISTS

- (a) CTU should carry out systematic load flow studies covering all the credible contingencies with possible voltage constraints. It is also important to execute and determine the load characteristic in relation to frequency and voltage parameters. This should be jointly done by CTU and POSOCO with the association of CPRI and IITs. At present we are using the load characteristics (PQ Versus V and f) as defined by Prof. Kundur or PTI and this may not be realistic.
- (b) The Oscillating State Stability Studies (Steady State Stability Studies with High definition Static Excitation system along with PSS and Limiters in action) should be invariably carried out.
- (c) Voltage Stability Studies should be done in detail. In this connection it is advised that CEA and PGCIL in particular should refer to WSCC Document entitled “Voltage Stability Criteria, Undervoltage Load Shedding and Reactive Power Reserve Monitoring” issued in 1998.
- (d) Appropriate allocation of shunt reactors on transmission lines as un-switched reactors, switched reactors on EHV busbars and MV reactors on tertiary winding of ICT should be managed in an approved sequence so that the EHV lines and the power system maintain the normal voltage profile within limits.
- (e) The Turbo-Generators limited MVAR absorption capabilities and that too is restricted by end-iron heating, rotor angle limiter and further need of keeping an operating margin.

This means under steady state operating conditions the thermal has limited reactive power absorption capability. With restraints of Quadrature Axis Vibration, the loading pattern on Generator becomes quite restrictive and should not be violated without endangering the life of the Generating units. To meet such operational requirements of the network, the system must be provided with suitable reactive power absorption devices, especially under light load conditions.

- (f) There is a need to seriously look into shortage of trained manpower available with CEA and CTU as early as possible and plan their specialized training so that Indian power system can be safely handled.

19. Formation of State Standing Committee

Committee suggests formation of state level Standing Committee to take up transmission planning within the state to ensure that matching transmission system within the state is planned and commissioned matching with inter-state transmission system.

CHAPTER-1

BACKGROUND

- 1.1. Transmission infrastructure is backbone for operation of a competitive electricity market. The Electricity Act, 2003 ushered an era of de-licensed generation and Open Access. Transmission is the link which synergises these two. However, achieving synchronization between a licensed activity of transmission and an open market & de-licensed generation coupled with Open Access poses few challenges as compared to the planning carried out with identified location & capacity of Inter-State Generating Station (**ISGS**) and their identified beneficiaries.

- 1.2. After implementation of the Electricity Act, 2003 and Open Access in Inter-state Transmission System (**ISTS**), for development of a robust transmission system in the country, the Commission in 2004 framed Regulations on Open Access in inter-state transmission system which were modified in 2009 namely Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access to the inter-State Transmission and related matters) Regulations, 2009 (**Connectivity Regulations**). The Commission also notified regulations like Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 (**Sharing Regulations**) and Central Electricity Regulatory Commission (Grant of Regulatory Approval for

execution of Inter-State Transmission Scheme to Central Transmission Utility) Regulations, 2010 keeping in view spirit of the Act, National Electricity Policy and National Tariff Policy.

1.3. The Commission, vide its order dated 31st May, 2010, in petition no. 233/2009 and order dated 13th December, 2011 in petition no. 154/MP/2011, granted regulatory approval for eleven High Capacity Power Transmission Corridors (**HCPTC**) for evacuation of power of Generation Projects of Independent Power Producers (**IPPs**) from power surplus areas of the Country to power deficit areas on the target region basis. However, the progress of generation projects of quite a few IPPs was affected due to various reasons like delay in land acquisition, delay in grant of statutory clearances and delay/change in fuel linkage policy. Many of the 11 HCPTCs have already been commissioned by CTU and rest are going to be commissioned in next one to two years. Further, due to issues related to State DISCOMs not coming forward for Case-I bidding, most of the IPPs have not been able to find long term beneficiaries even after five to six years of grant of Long Term Access (**LTA**).

1.4. The Commission has received views of Transmission System Planners namely CEA and CTU and the System Operator, POSOCO on the Connectivity Regulations. IPPs have also raised their concerns in regard to the present

mechanism and issues faced by them. Further, CEA and CTU are moving ahead from their initial position of requiring firm beneficiaries of Inter-State Generating Stations (ISGSs) in advance to a more market friendly approach and CEA mooted the concept of General Network Access (**GNA**) to address the issues raised by CEA, CTU, POSOCO and IPPs.

- 1.5. In view of the issues raised by CEA, CTU, POSOCO and IPPs, the Commission decided to have a relook at the prevailing Regulations and accordingly published “Staff Paper on Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues (**Staff Paper**) in September, 2014 to seek views of Stakeholders on important issues of Transmission Planning, Connectivity and Access to ISTS in the country.
- 1.6. The objective of Staff Paper was to initiate a debate on transmission related issues such as
 - (i) Whether integrated and coordinated transmission planning is required to adopt new market reality or LTA based planning is to be continued?
 - (ii) Which cost is to be assigned to Generator?
 - (iii) How to handle Exit and delay in commissioning of generation projects.
 - (iv) Any exit to be considered in accordance with various parameters like time of request for exit, shifting of target region, stage of investment of the transmission system,

impact of exit, shift on existing ISTS customers and future scenario of usage of the asset.

- (v) Whether transmission planning needs Regulatory Guidance?
- (vi) Flexible access - Connectivity Access or Connectivity plus Injection Access or Connectivity plus full network Access (Alternative-1) or fixed access corresponding to Installed Capacity (GNA)?

1.7. The Commission had, vide public notice dated 19.9.2014, invited comments of the stakeholders and other interested persons on the Staff Paper by 20.10,2014, which was further extended to 10.11.2014 and 30.11.2014 vide notices dated 24.10.2014 and 17.11.2014 respectively.

1.8. The Commission has received written comments/ suggestions from 24 Stakeholders/ interested persons. Comments are available at www.cercind.gov.in.

1.9. The Commission vide Office Order dated 8.12.2015 formed a Committee to “Review Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues” with following composition:

- (i) Shri Mata Prasad, Power System Expert- Chairman
- (ii) Shri Rakesh Nath, Former Member, APTEL-Member
- (iii) Shri A. S. Bakshi, Member CERC- Member

(iv) Ms. Shilpa Agarwal, Dy. Chief (Engg.), CERC- Nodal Officer

The Committee invited Shri A.K. Saxena, Ex-Chief Engg., (CERC) as a special invitee for all its meetings.

1.10. The Terms of Reference (ToR) of the Committee are as follows:

- (i) To study Staff Paper on Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues;
- (ii) To analyse the comments received in response to the above Staff Paper;
- (iii) To suggest an appropriate regulatory intervention with Draft Regulations.

A copy of the aforesaid CERC Office Order is at ***Annexure-I***.

1.11. The Committee had in total 15 meetings during which it heard the views of a number of experts and concerned organisations like statutory bodies (CEA, CTU, POSOCO, MoP), Power system experts, Representatives of States (STU/DISCOMs) and representatives of generators during January-May, 2016.

1.12. The Committee noted the issues raised by transmission planning agencies, system operator, Ministry of Power, stakeholders including generating companies, transmission

licensees, STUs, DISCOMS as well as power system experts. The Committee finds that the issues broadly fall in following heads :

- (i) Conceptual basis of transmission planning (LTA or Deep and Shallow Connection or GNA) and stakeholders participation in the planning process, handling mismatch between commissioning of generator and transmission system reservation of capacity for STOA / Power Exchanges.
- (ii) Need for granting Connectivity separately, the charges for Connectivity, inordinate time taken by the generators in applying for LTA after grant of Connectivity, application for LTA being much less than IC, Charges for Relinquishment of LTA etc.
- (iii) Application Fee and Bank Guarantee towards construction of transmission system
- (iv) Utilisation of Congestion Charges
- (v) Few other issues prevailing in sector

The issues in regard to the above are summarised in succeeding chapters along with recommendations.

CHAPTER-2

STAFF PAPER

2.1 Introduction

The Commission published the Staff Paper in September, 2014 which covers the existing regulatory mechanism governing grant of connectivity, long term access, medium term open access and other related issues, issues raised by transmission planners, system operator, generators, users, open access consumers and power exchanges. The Staff Paper also covers transmission related issues and solution suggested by CTU/CEA and POSOCO and the regulatory mechanism for providing long term solutions the issues raised by transmission system planners, system operator and other stakeholders.

2.2 Issues raised in the Staff Paper:

2.2.1 Issues raised by Transmission Planning Agencies:

- (a) Few players apply for LTA for their entire capacity, some of the players have sought only connectivity or LTA for part of the capacity, thereby having little or no commitment to pay for the transmission charges.
- (b) The provision of connectivity to ISTS without any payment of transmission charges is being misused by the IPPs.
- (c) Many generators are transacting power through STOA which is administered by RLDCs and is granted considering the spare capacity in the system. Transmission is a lumpy investment and the spare capacity in the system

would vary from time to time. If a number of generators apply to RLDCs for STOA, it puts undue pressure on the last mile player viz. RLDC. This also has the potential for insecure operation of the grid. This phenomenon is going to increase day by day as more and more IPPs are getting connected to the grid without any long term PPA and LTA.

- (d) Generators are not approaching CTU well in advance for grant of connectivity and LTA leading to a significant time interval between grant of connectivity and commencement of LTA as LTA becomes effective most of times only after reinforcements in the transmission system.
- (e) Some of the generators are either abandoning their project or requesting for surrender of LTA or are rescheduling their projects which is affecting implementation of some of the high capacity transmission projects.
- (f) Issue of Exit in the era of Open Access is not a simple matter which can be decided only on the basis of "stranded capacity" but issue of affecting other party's market access and its effect on competition is also a matter of concern. Any exit needs to be considered in accordance with various parameters like time of request for exit or shifting of target region, stage of investment of the transmission system, impact of exit or shift on existing ISTS customers and future scenario of usage of the asset.
- (g) It is difficult to plan the transmission system i.e. in which direction as most of generators are seeking LTA without beneficiary(s).

- (h) It is difficult to plan the transmission system for the drawee entities as they are not giving their drawal requirement from ISTS.

2.2.2 Issues raised by System Operator:

- (a) For a number of reasons, stakeholders, who have been granted connectivity are not availing the LTA as they are able to evacuate power through MTOA and STOA.
- (b) Many generators have sought reduction in LTA which may create issues with regard to sharing of transmission charges
- (c) Exercise for planning of the generation/ transmission system starts quite well in advance and it is very difficult to identify beneficiary so much in advance
- (d) There is no commitment to payment of transmission charges if LTA is not taken.
- (e) Hydro power stations have low load factor of the order of 30-40% only. By selling power through STOA, they can save as much as 60-70% of transmission charges, though the concerned transmission network mainly caters to their requirement only.
- (f) The generators by connecting to the grid are availing the benefits of reliability support without any charge

2.2.3 Issues raised by Generators:

- (a) Few generators were granted LTA based on target region and faced many problems like difficulty in paying long term

transmission charges as they did not find any firm beneficiary.

- (b) In many cases generators were accommodated on existing network margins but after a few years they started facing the problem of congestion in the system due to coming up of new generators which required the same network for transfer of power.
- (c) Generators could not avail LTA because of no firm beneficiaries and with the coming up of new generation capacity their applications for access are considered at par with the new generators i.e. under MTOA/STOA, which resulted in congestion.
- (d) The right of network use depends on type of access along with type of contract with buyer. As generators were having LTA to ISTS without firm beneficiaries, they started demanding right of use or at least 'first right of use' i.e. they sought priority in availing STOA. However, in the case of short term contract (of power) under STOA, any priority to holder of LTA to ISTS cannot be given, but such types of requests overwhelmed the system operator resulting in increase in litigation. Although a commercial adjustment to these generators was given in the form of adjustment of Long term open access charges with short term charge paid (for injection in any region and with-drawal charges in target region), it does not solve the problem of congestion. Therefore, the rights of Long Term Access customers are required to be clarified.

2.2.4 Issues raised by Users, Open Access Customers and Power Exchanges:

- (a) DISCOMs are facing problem of congestion in getting MTOA and STOA.
- (b) Open Access Customers in search of efficiency of power procurement want to utilise power market but are finding it difficult to get power on regular and reliable basis due to congestion.
- (c) The congestion in ISTS is less frequent than congestion in intra -state transmission system where requisite development of state's transmission system network has not taken place due to various reasons. The issue of congestion needs to be handled through better transmission planning and operational management of grid rather than a commercial arrangement of forcing LTA or limiting all transactions to the overall limits of LTA availed by generators/ drawee entities.
- (d) Power Exchanges, which are transparent platforms for transactions, are facing problem of Congestion more frequently than bilateral transaction as allocation to Power Exchanges is being done in the end. An analysis shows that due to this tendency, economic operation of power sector i.e. merit order operation gets disturbed.

2.3 Suggestions made by different stakeholders

2.3.1 Suggestions made by System Operator

System Operator has suggested that it should be made mandatory for the new generators to apply for LTA corresponding to the quantum that they should be injecting into the grid, including overload capacity. It has also been suggested that all transactions by an entity, including Long-Term with identified beneficiary, MTOA and STOA should be limited to the quantum of LTA availed.

2.3.2 Suggestions made by CEA

The solution suggested by CEA is based on concept of GNA wherein system planning is proposed to be based on GNA i.e. Injection and Drawal requirement and transmission charges should also to be paid on the basis of GNA.

2.3.3 Suggestions made by CTU

- (a) For the new IPP generation including captive power station eligible for getting connectivity with ISTS, it should be made mandatory to apply through combined application for Connectivity and LTA. However, renewable and solar generation projects may be exempted from this stipulation
- (b) LTA may be categorised in two categories viz. LTA with firm beneficiaries and LTA with target beneficiaries.
- (c) There should be provision of assigning responsibility of development of Connectivity line by IPP developers if they are required in the time period less than the 9 months CERC time lines.
- (d) Pre-requisites in the form of achieving milestones before taking up Implementation of Transmission System for grant of LTA/Connectivity may be defined.

- (e) New generators seeking connectivity should also apply for LTA corresponding to the quantum that should be injected to the grid after discounting for auxiliary consumption.

2.4 Regulatory Mechanism for providing long term solution

2.4.1 Transmission Planning philosophy

- (a) After detailed analysis of the issues raised by CEA, CTU and POSOCO, the Staff Paper proposed to formulate a mechanism for development of a robust and flexible ISTS. In the Staff Paper it has been underlined that the problems being faced in the country are not unique. Every country which has carried out power sector reforms like unbundling of integrated utilities, de-licensing of generation and open access, faced similar problems due to uncertainty in regard to development of generation and demand. In a changing scenario, approach of all stakeholders also needs a change. In a way, we are fortunate that the gaps between generation and transmission in our country have become apparent within a short span of time and corrective course of action is feasible. A comprehensive solution in this regard has been proposed in the Staff Paper as under:
 - (b) Transmission planning should be based on installed capacity with anticipated load and generation. This would ensure implementation of intent of the Act that all types of access should be accommodated. This will also ensure that there is no congestion on the injection side.

- (c) In order to facilitate informed decision making by all stakeholders like STUs and generators planning to take location decision, following plan is proposed:
- (i) CTU should publish load-generation balance for different scenarios for next three-five years in consultation with CEA and POSOCO.
 - (ii) STU should submit their next five year injection and drawal estimates to CTU and CEA in the format prescribed under the Grid Code. This should be done on the rolling basis in the month of January every year for the next five financial years.
 - (iii) The Planning agencies should inform the Commission, in case information is not filed by concerned STU.
 - (iv) A validation committee similar to the one constituted under Sharing Regulations should be incorporated in the Grid Code for this purpose.
 - (v) The STUs should be kept informed by respective Load Despatch Centre on quarterly basis about the deviations of actual Drawal of entities from the ISTS as compared to their projections. If deviation was found persistent, necessary action may be initiated by STU against the concerned utility/entity.
 - (vi) As only injection and drawal data should not be sufficient for transmission planning process, complete data about network along with planned addition of generation and load within the STU area should be given by all users/entities to STU in January every year. Network data in suitable format should also be

published by CTU & POSOCO for the All India transmission network. The access to this data to authorised entities should be based on 'credential control through username/password.

(vii) For every transmission system planned and proposed three possible scenarios of expected load and generation (Normal, optimistic and pessimistic) should be given. The transmission system should also be proposed for three possible scenarios and consequences of opting for any particular transmission system should be elaborated. The consequences should include benefit identification and present and future requirement to be catered by the proposed system. Possible cases of congestion in case of opting for a particular scenario must also be brought out clearly. In this connection future generation load growth along with pocket of possible ROW problem need to be brought out clearly.

(viii) After firming up a transmission system, an Environmental Impact Assessment (EIA) should also be brought out for consideration of all stakeholders and if required rerouting of proposed transmission system must be done to make minimal environment impact. Input from other government agencies may be taken at the planning stage itself, like status of clearances etc., to avoid future problems in execution of the scheme.

- (d) We need investment in generation to make affordable power available to all. Similarly we need investment in transmission optimally so that assets are utilized in an efficient manner and infrastructure financing can be done for all sectors of economy, without a sector crowding out other sectors. In deregulated generation scenario the investment for transmission for upcoming generating projects is basically divided into following areas:
- (i) Shallow Connection – Connectivity of generator to nearest grid point or pooling point.
 - (ii) Deep Connection- Network upgrades required in large grid network to enable power flow from pooling point to load utilities with compliance of existing Reliability Standards.
 - (iii) Mixed or shallow connection charging- The mixed or shallow method of connection charging combines the shallow and deep methods. This approach can be seen as a "compromise" between the two objectives of giving some locational incentives and reducing the burden on the producer to pay grid reinforcement costs.
- (e) Proposed formulation for connectivity and Long Term Access

A. Alternative-I

- (i) Transmission expansion is initially attributable to generators and later shifted to beneficiaries.

- (ii) Choice of product will be given to applicant and in accordance with the choice, applicant will get transmission service.
- (iii) Construction BG to be furnished by applicant would be equivalent for capital investment to be made in transmission system. In case applicant has full site control (Availability of land, Water, Environment clearance, etc.) then amount of bank guarantee would be less.
- (iv) In case of no transmission system augmentation is required, BG will be corresponding to seven year zonal transmission charges.
- (v) Three types of products are proposed to be offered in Alternative-1:

Option-A: Connectivity plus Full Network Access

Option-B: Connectivity Access

Option-C: Connectivity plus Injection Access

Summary of these options is given below:

Type	Network	Bank Guarantee (BG)	Facility	Exit	Transmission Charges
A	Connectivity plus network Access	Connectivity line (non-refundable) plus Network Access - Adjustable BG	Full Access	12 year NPV of transmission tariff for new assets	Usage based
B	Connectivity	For full cost of Connectivity Line (non-refundable)	Only assured connectivity	Bank Guarantee will not be refunded	Fixed Monthly tariff for connectivity line plus 25% of Average Access charge for installed capacity (Adjustable against STOA)
C	Connectivity plus injection	Connectivity (non – refundable) plus 50% of Network- Adjustable BG	Only target Region access	12 year NPV of transmission tariff for new assets	Usage based

^ For construction of connectivity portion, cash advance will be taken while for Access portion Bank Guarantee may be taken.
 ^^ The Bank Guarantee shall be initially valid for 5 years .It should be issued by Bank / Financial institution approved by CTU.

B. Alternative 2: GNA

Under Alternative 2 transmission planning execution and transmission cost allocation should be based on GNA concept as proposed by CEA and CTU as detailed under:

- (i) Whenever a Generator or Drawal customer wants connectivity and access to ISTS, it will declare its GNA requirement.

- (ii) For Generator, GNA would correspond to its Net Installed Capacity (i.e. Installed capacity – Auxiliary consumption). Generator should also consider its overload capacity and that shall be considered as its GNA.
- (iii) Transmission system shall be planned based on GNA requirement of Generator and demand customer and 100 % evacuation irrespective of target region is proposed to be assured.
- (iv) To handle the scenario when drawl GNA is less than Injection GNA then planned transmission system would be developed in accordance with drawal GNA. In this situation option would be given to Generators to bear both injection and withdrawal GNA for differential i.e. for an application period if additional (new) demand GNA requirement is say 7000 MW and application for injection GNA is 10000 MW then Generator may be asked to bear GNA responsibility of both injection and withdrawal for 3000 MW in addition to 7000 MW injection GNA.
- (v) Confirmation from Generators and demand customers may be sought before starting the tendering activities for planned transmission system and transmission planning, if required, may be modified.
- (vi) A status check of progress of statutory clearances like land, fuel, water and environment clearance may be checked before commencement of execution of transmission system. In case it is found to deficient to a

large extent, the executing agency for transmission system may approach Commission for guidance.

- (vii) Both Generator and demand customer shall submit bank guarantee corresponding to their GNA.

2.4.2 Bank Guarantee

It was proposed that generator should pay advance in form of sufficient(100%) bank guarantee for cost of Transmission system both for Connectivity (Shallow connection) and Network expansion(deep Connection)- These guarantees are to be given in stages and just before the execution is to be started for transmission system. In case of exit before commissioning entire bank guarantee should be retained. After Commissioning bank guarantees to be returned in proportion of firm PPA and in case of no PPA bank guarantee proportional to NPV of 12 year transmission charges for newly constructed transmission system will be retained. Every year the amount of bank guarantee would get reduced corresponding to balance period i.e. after 3 year it will be taken corresponding to 9 years NPV (12-3 years).

2.4.3 Treatment of delay and exit

After a grace period of three months during which Generator should be responsible for IDC liability, staggered payment system for 25%, 50 % and 100% transmission charge should be applied for deep connection (network expansion) for delay of each quarter. For competitively bid

projects no relaxation should be allowed in case of delay in commissioning of generation project. It is proposed that if generating station is not commissioned at all, it should bear NPV of transmission charges of new assets for 12 years depending upon type of access A, B or C it sought.

2.4.4 Other Issues

In the Staff paper certain other important issues such as transmission capacity allocation mechanism for power market- collective transactions and utilization of transmission charges collected through e-bidding and congestion revenue were also brought out. It was proposed that a window for collective participants, giving equity with bilateral participants for transmission corridor booking under short-term market be considered. Collective participants should be allowed to participate in booking Transmission Capacity in STOA 'Advance' and 'FCFS' categories. Such collective participants would use the pre-booked transmission capacity of a particular corridor to participate in Power Exchange Day Ahead Market (DAM) and get scheduled based on the corridor already reserved by the participant. It was also proposed that any amount received through e-bidding and congestion revenue be adjusted towards transmission charges to be paid by all DICs on quarterly basis.

2.4.5 Questionnaire for Stakeholders

Specific comments of stakeholders were sought in the Staff Paper on critical decision points in the form of a questionnaire. The questions and the responses of stakeholders, in brief, are given in Chapter-3.

CHAPTER-3
SUMMARY OF COMMENTS/SUGGESTIONS BY
STAKEHOLDERS ON STAFF PAPER

Summary of response and suggestions of stakeholders to the questions raised in the staff paper is given below:

Question – 1: Whether Connectivity should be retained as a separate product?

- (i) Except Adani Power and IEX, all other 22 stakeholders answered in affirmative i.e. connectivity should be retained as a separate product.
- (ii) POSOCO – Connectivity may be retained as separate product only as in-principle approval by CTU for facilitating sitting of generation project (finalizing technical specifications) and for financial closure of a generation project. However no injection or drawl of power should be allowable with only connectivity.
- (iii) GRIDCO – Connectivity may be retained as a separate product with the condition of up-front payment of the cost of the ‘Dedicated Transmission Line’ by the Generator if the said dedicated line is built by the CTU and in shape of BG if the dedicated line is to be built by the Generator itself.
- (iv) POWERGRID – Since connectivity lines will be utilised only if the generator comes, these may preferably be implemented by generators themselves so as to avoid the issue of mismatch and payment of transmission charges in case of delay in generation resulting in any litigation. In

case the Commission decides to implement connectivity lines through transmission licensee, it may be linked to submission of Construction BG by generators.

- (v) Thermal Powertech – For specific generators whose Connectivity and LTA quantum's are different viz. multi model business (own consumption and power sales), renewable generators, peak operating generators (Gas stations) etc., Connectivity may be retained as separate product.
- (vi) Shri Shanti Prasad – Connectivity and initial LTA should be equal to injected capacity (IC less APC as per CERC regulations less the captive load for CPP). Connectivity to be permitted against non-refundable registration/ connectivity charges @say Rs.0.15 lakhs per MW (towards creating over capacity for GNA) and cash security deposit of sum equal to say 12 month's charges @ POC (injection) + POC (drawl) at normative PLF as per CERC regulations applied to injected capacity and construction cum operational BG for equivalent amount.

Question – 2 (a): If yes, what are in your opinion are the advantages of Connectivity as a separate product?

- (i) Dhariwal Infrastructure – Generator shall be able to synchronise their unit with the grid without waiting for getting a customer. It will enable the generator to test their unit for performance test. Also it will enable the generator draw commissioning power.

- (ii) Essar Power – Approval to connect to Grid is one of the critical milestone in project development phase for securing Finance for the project from Lenders.
- (iii) GUVNL – Connectivity enables Generating Stations to know in advance, the connection point up to which they need to build their dedicated line. Prior agreement with the beneficiaries would not be a pre-condition for network expansion.
- (iv) MP Poorvkshetra Vidyut Vitran – In case of certain force majeure conditions, if the project of the Generating Company does not materialize, the Generating Company would not be burdened with the cost of transmission charges for the evacuation system which could have been created in a bundled product. This would also ensure that stranded capacity is not created in ISTS.
- (v) MB Power, Jindal Power, KSEB, Simhapuri Energy – a) Financial Closure of the Generating station b) Finalisation of Switchyard of the Generator including the Generator Transformer c) Drawl of Start-up power d) Finalization of the transmission system for injection of power by the generator.
- (vi) NTPC – Time frame required for providing physical connectivity and creation of evacuation system as per LTA are different particularly for green field project, 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. 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.

- (vii) Shri Shanti Prasad – Transmission system developed based on GNA may not have adequacy of transmission in all directions. LTA will therefore has to be sought/ altered from time to time when beneficiary (under LTOA, MTOA or STO) is identified/ altered to enable transmission utility to indicate constraints, if any. This will enable system augmentation for such constraint.
- (viii) Thermal Powertech – Enabling DIC to seek the network access less than his actual connected capacity with the Grid.

Question-2 (b): If connectivity is retained as a separate product, then whether it should be free or transmission charges should be borne by generator or drawee entity which is applying for connectivity?

- (i) Essar Power, KSEB, NTPC, Simhapuri, Tata Power – Connectivity should continue to be free product.
- (ii) Dhariwal Infrastructure, GRIDCO, GUVNL, Shri Shanti Prasad, PTC, MP Poorvkshetra Vidyut Vitran – Connectivity should not be free of cost.

- (iii) APP – Only specific connectivity network (shallow connection) should be charged. Investment in transmission system beyond shallow connection should be recovered through access tariff.
- (iv) MB Power – Associated transmission charges should be borne by the drawee entities
- (v) Thermal Powertech – 20% of the ARR may be charged to all the users of the grid as part of connectivity charges and remaining 80% of ARR may be recovered through Marginal participation pricing mechanism/Usage based

Question-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?

- (i) Essar Power, Jindal Power, MB Power – There should not be any charge, and transmission charges should be levied on Open Access provided under Short Term depending upon availability of corridor.
- (ii) GRIDCO, GUVNL, PTC, Simhapuri, Thermal Powertech, MP Poorvkshetra Vidyut Vitran – Connectivity charge should be mandatory.
- (iii) APP, GUVNL – Only corresponding to connectivity network
- (iv) Dhariwal Infrastructure – Grid charges equal to 25% of the normal grid transmission charge should be levied.
- (v) NTPC – Only 25% charges should be payable for the transmission line made for the purpose of start-up power.

- (vi) Sh. Shanti Prasad – Transmission charges to be based on PoC charges which can be in two parts: part I - as per actual usage PoC (injection) payable by generating company and PoC (drawl) by drawee and part-II difference, If any, between minimum of normative usage charges for PoC (injection) + PoC (drawal) and actual as per part-I, payable by generating company on monthly cumulative basis.

Question-3: If no, what in your opinion are the disadvantages of Connectivity as a separate product?

- (i) Adani Power, APP, IEX, Thermal Powertech, Tata Power –
(a) Generator may delay the LTA application (b) Generator may not apply for full load LTA (c) Recovery/payment of transmission charges for power transmitted over LTA limit becomes a problematic issue (d) Possibility of insecure grid operation (e) resulting in inadequate planning/development of transmission system and leading to transmission congestion
- (ii) Essar Power, MP Poorvkshetra Vidyut Vitran, MB Power –
There is no disadvantage as exit/delay in generating project commissioning would be protected by adequate BG.
- (iii) Sh. Shanti Prasad – Generating companies applying for LTA less than injectable capacity and thereby transmission capacity (built up based on generating capacity) remaining unutilised.

- (iv) POSOCO – (a) Connectivity as a separate product would only capture the envisaged site of generation capacity addition without any information regarding the quantum of injection in the planning time horizon. Thus it adds to the uncertainty for the transmission planner. (b) Transmission is a lumpy asset that requires sufficient lead time for execution.

Question-4: 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?

(b) Is a proposed bank guarantee equivalent to cost of transmission line sufficient?

(c) Is proposed bank guarantees are very high?

- (i) APP, Essar Power, Jindal Power, IEX, Tata Power, NTPC – Yes, the existing construction BG of Rs 5 lakh per MW is sufficient. Proposed BG is very high.
- (ii) Adani Power, Simhapuri, Thermal powertech – The existing BG of Rs. 5 Lakh/MW is too low. Proposed BG is very high.
- (iii) GUVNL: The bank Guarantee should be at least 50% of the Transmission Project cost or equivalent to NPV of 12 years charges which can be invoked and appropriated towards reduction of the transmission charges (redundancy

portion), so that burden of the same should not fall on existing transmission users.

- (iv) GRIDCO, MP Poorvkshetra Vidyut Vitran – Existing construction BG amount (Rs 5 lakh per MW) is not sufficient. Proposed BG should be equivalent to cost of transmission line. Proposed BG is not very high.
- (v) Dhariwal Infrastructure – It should not be 5 lakh or one cr/MW rather it should be related to apportioned project cost and should not be more than 10% of the apportioned project cost for augmentation of transmission system.
- (vi) POWERGRID- BG to be submitted by an applicant should be a fixed amount per MW, say Rs 50 lakh per MW. The applicant seeking access to ISTS under Type A and C shall submit an “Access BG” (adjustable as proposed by CERC) of Rs 50 lakh per MW corresponding to MW for which access is required. For generators applying connectivity access under Type B, an access BG (adjustable for NPV of 25% of PoC charges for 12 years) of Rs 20 lakh per MW shall be submitted corresponding to MW proposed to be connected, as a deterrent to non-serious applicants. The amount of BG/ MW shall be escalated every two years as per an index as found suitable by the Commission.
- (vii) POSOCO – The existing Bank Guarantee is not sufficient and in line with proposal of CTU, the Bank Guarantee may be raised.
- (viii) KSEB – Amount of BG may be fixed as amount corresponding to the net present value of the expected

transmission charges for 5 years from the date of COD of the transmission system for the construction period.

- (ix) Sh. Shanti Prasad – Transmission charges of 24 months will be more appropriate - 25% of it as cash security deposit and 75% in the form of BG.

Question-5: 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**
- (i) GUVNL, POWERGRID – Option (a): NPV equivalent to 12 years transmission charges
- (ii) GRIDCO, Tata Power – Option (b): NPV equivalent to 7 years transmission charges, taking into account the construction period of generating station, commissioning thereof and not to burden the consumers with higher tariff as well as the period will be sufficient enough to find out an alternative Generator, even by incentivizing such Generator(s), depending on the condition(s) for which the previous Generator had backed out.

- (iii) IEX, MP Poorvkshetra Vidyut Vitran, Simhapuri – Option (c): X Rs./MW of installed capacity – One time charge, as CTU has pointed out the difficulty in finding out the stranded assets in a meshed network
- (iv) APP – Construction BG equal to NPV of estimated charges 12 years only for connectivity lines up to pooling point which are exclusively utilized by the respective generating station(s). For the system beyond pooling point, that is the system towards LTA or GNA, BG of Rs.5 lakhs/MW to be taken at the time of application approval
- (v) Adani Power, Jindal Power, KSEB, MB Power, NTPC, Statkrafts Markets, Thermal Powertech – Option (d): Five years Average Injection and withdrawal charges, BG amount shall be equivalent to 3 to 5 years of transmission charges payable for the GNA capacity
- (vi) Dhariwal Infrastructure, Essar Power – Option (e): Five years average injection charges only, as each year's transmission tariff is around 20% of the project cost and compensation can be at best for 100% of the project cost. This should also be payable each year and not upfront. Additional BG cover can be kept to safeguard against default
- (vii) Sh. Shanti Prasad – BG based on PoC charges will be more appropriate. BG to be based on injection at normative PLF and auxiliary consumption
- (viii) POSOCO – The Bank Guarantee amount should be sufficient to bring in seriousness regarding entry as well as exit.

Question-6: In case of delay in generating unit(s) /project:

- (a) Date of LTA should be firm and no relaxation should be provided.**
 - (b) If information of delay is provided sufficiently in advance some staggered relief can be granted.**
 - (c) Issue should be decided mutually between generating company and transmission licensee subject to condition that no burden is transferred to other users.**
-
- (i) POSOCO, GUVNL – Option (a): Date of LTA should be firm and no relaxation should be provided. Burden should not be transferred to other users.
 - (ii) Adani Power, APP, Jindal Power, Essar Power, NTPC, Thermal Powertech, Tata Power – Option (b): If information of delay is provided sufficiently in advance some staggered relief can be granted, the relief may be granted on case to case basis after thorough analysis for maximum permissible delay. Further bi-annually meetings should take place between Generator developer & Transmission licensee to match the commissioning schedule
 - (iii) MP Poorvkshetra Vidyut Vitran, KSEB, Statkrafts Markets – Under force majeure conditions, LTA date may be relaxed
 - (iv) Adani Power, APP, Dhariwal Infrastructure, GRIDCO, MP Poorvkshetra Vidyut Vitran, Shri Shanti Prasad, Simhapuri – Option (c): Issue should be decided mutually between generating company and transmission licensee subject to condition that no burden is transferred to other users,

however, in case of any dispute, the Commission may be approached

- (v) GUVNL – The only option is Generator should start paying transmission charges from the date of LTA irrespective of delay in commissioning of Generating Units / Project
- (vi) IEX – The “delaying party” should bear the burden arising out of delay. In case of delay due to force majeure, Option (c) should be adopted since it has equitable proposition for both the generating company and transmission licensee.

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 should bear the Grid level transmission charges.

- (i) Association of Power Producers (APP) and Adani Power Limited (APL): Mere shallow connection may not be desirable as it would have a tendency to restrict the network planning process leading to congestion. Shallow Connection should be permitted only to the renewable generators, as the same could be accommodated in the grid margins. However, for conventional generation and even for larger quantum of renewable generation, system

strengthening would be required at some critical segment of deep network. It would be appropriate to recover the cost of shallow connection from GNA customer, if it is a point to point transmission element. In other cases, the same may be pooled.

- (ii) IEX: Shallow Connection may be adopted for both renewable and conventional generators. The transmission planning must be based on the net installed generation which must be reinforced through load-generation balance for next five years under different scenarios by the CTU and injection/drawl estimates submitted by STUs on rolling basis in beginning of each year for the next five years. As regards investment towards the grid level charges, these should be incurred by the CTU and recovered from the constituents through the PoC mechanism. Further, an important aspect in planning which needs to be incorporated is consideration to economic dispatch of power.
- (iii) GRIDCO: Full Shallow Connection and partial Deep Connection are applicable in Indian condition in terms of transmission charges. Shallow Connection should be free of cost for renewable generator up to an installed capacity of 5MW. For other generators including renewable, it should be on chargeable basis. On Transmission Planning, the mandate by NEP is clear that prior agreement with the beneficiaries would not be a pre-condition for network expansion. The generator will bear the transmission charge till firm beneficiary(ies) are identified, after which it will be

the responsibility of beneficiary to pay the transmission charges.

- (iv) GUVNL: Worldwide Connectivity and Access to the grid user are provided as a separate product and charged accordingly, which our country should accept and adapt to fit our kind of requirement. Shallow Connection should be provided for Renewable Generators whereas for Conventional Projects, Deep Connection should be provided. Since Shallow Connection system is allowed only to RE Generators, the transmission planning will be done by CEA & CTU looking into RE potential and expected capacity addition. The cost of augmentation shall be incurred by Grid Operators and to be recovered from all the beneficiaries including RE.
- (v) POSOCO: POSOCO supports the concept of Deep Connection wherein the producers will pay for the costs of the equipment needed to connect their plant physically to the nearest point of the electricity distribution grid, plus all the cost of any network reinforcement necessary to connect their plant. Shallow Connection is not desirable in Indian context and should not be permitted for conventional generators.
- (vi) KSEB: GNA is one form of deep connection method which enables system strengthening based on load generation balance and resolves the present transmission system crisis. Considering the importance of ensuring a healthy transmission system based on load generation balance of the country, KSEB strongly recommends the Deep

Connection. However, as provided in the National Electricity Policy, Shallow Connection method may be followed for renewable generators.

- (vii) NTPC: In India, connections are 50% Shallow type + 50% Deep type. However, majority of the countries are following shallow connection system. The PPAs in the entire country are generally at ex-bus so it should not be disturbed. However, for RE projects, a shallow connection may be introduced subject to certain conditions e.g. for RE project capacity less than 250 MW and lines up to 33kV pooling point should be in scope of RE Project. Any system from 33kV and above must be implemented by CTU/STU. Besides in case of CGS, whenever any RE project is being set-up, it should be allowed to be integrated with existing electrical system of the plant at any voltage level. There is an urgent need of segregation of transmission charges for RE projects and cost of transmission system augmentation should be met by from PSDF and through RE cess on STOA/Power exchange as the margins created for RE projects should be utilized by Power Exchanges/STOA when RE projects are not in service. Shallow Connection should be permitted to both renewable and conventional generators.
- (viii) Thermal Powertech, Mytrah Energy: Shallow Connection only for Renewable Projects.
- (ix) TATA Power: The shallow method of connection minimizes the costs for producers, and allows the expected cost of their projects to be estimated at an early stage. This type of

connection is appropriate for Renewable Sources. Shallow connection should not draw any charge, as it is similar to Connectivity. Only upon accessing the system, charges should be levied. Considering the inherent properties of renewable energy, a concessional Access Charge (may be 50% of that applicable to conventional sources) can be considered. Shallow connection can be implemented for both renewable and conventional Generators. Transmission Planning has to be based upon the capacity and not on shallow connection and charges for utilization of grid has to be paid by all the users.

- (x) Dhariwal Infrastructure Ltd, Essar Power and JPL: Shallow Connection should be adopted for both Renewable and Conventional generators.
- (xi) MPPKVNL: Both products i.e. Deep and Shallow, should be available. Shallow connection should be permitted to both with the condition to pay some part of transmission charges.
- (xii) MB Power: Shallow connection with GNA. Shallow Connection should be permitted to both Renewable generators and conventional generators. The transmission charges should continue as per the PoC concept.
- (xiii) Sh. Shanti Prasad: Shallow concept should be followed as this will bring parity between RE generation and conventional generation.

Question No. 8: Whether you are an Injecting Entity or Drawee Entity or both?

- (a) Injecting Entities: Adani Power, Jindal Power, MB Power, Simhapuri Energy Limited, NTPC, Thermal Powertech, Mytrah Energy, Dhariwal Infrastructure Ltd, Essar Power
- (b) Drawee Entities: M.P Poorvkshetra Vidyut Vitran, GUVNL,
- (c) Both Drawee as well as Injecting Entities: Tata Power, KSEBL, IEX, PXIL, TPTCL, PTC, GRIDCO, TANGEDCO

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?**
- (c) 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?**

- (i) Adani Power: The key of success of GNA depends on dissemination of proper and near accurate information from various users/states. A separate stringent regulation to ensure information flow may be brought in by CERC. The proposed methodology of transmission access and transmission charges, under alternative 2 for GNA seems to be appropriate. The amount of BG may take into consideration the resale/scrap value of the asset, possible redeployment of transmission assets, risks to be borne by other beneficiaries, etc. and may consider linking BG amount to the transmission charges payable for 3 to 5

years and encashment of BG if not used for 2 years from effective date of access. In order to achieve objectives of the Act and come out of the present scenario of congestion in the transmission network, transmission planning to give assured access in all directions must be made possible.

- (ii) GRIDCO: GNA mechanism does not address the issue of relinquishment charges, Non-discriminatory Open Access, under-utilisation of Assets, payment liability on other users in case Generator is not able to find beneficiary, etc. Sharing of Transmission Charges should be on the basis of actual usage as envisaged in EA-2003, NEP and Tariff Policy instead of contracted power as envisaged in GNA. It is also not possible to plan system for 360degree dispersal of power.
- (iii) GUVNL: GNA is building of transmission system on 360degree basis on the basis of data of injection GNA and drawl GNA. However, in reality the actualization of forecasted scenario is difficult in wake of power sector issues like delay clearances, fuel issues, liquidity problem, behaviour of open access consumers, captive generators, DISCOMs financial health, etc. Again under declaration of GNA is also an issue. Transmission system developed on 360degree basis may have consequences in form of excess transmission capacity build, redundancy, burden of transmission charges without actual usage, etc. The transmission system and the transmission access should be developed based on Installed capacity. BG and Exit charges should be total transmission project cost.

- (iv) POSOCO: GNA concept puts forth that generators may be granted GNA based on their net installed capacity and overload capacity. This will ensure that the new transmission corridors are planned based on GNA requirement, helping in alleviating congestion. Injecting entities and drawing entities shall have the flexibility for point of injection/drawal subject to conditions laid down at the time of grant of GNA. POSOCO is of the firm view that it should be adopted forthwith. Though assured access in all directions may not be possible even under GNA mechanism, it would facilitate capturing the intended use of transmission by the market players.
- (v) IEX: GNA as proposed by CEA should be adopted for transmission access and transmission charges. In case of Exit, BG towards connectivity line upto the pooling sub-station may be forfeited. In case the transmission system is planned and developed based on thorough and periodic assessment of both the generation as well as the demand, it will indeed be possible to give assured access in all directions.
- (vi) Jindal Power, MB Power, Simhapuri Energy Limited, Essar Power: have favoured GNA and are of the view that GNA should be accepted for transmission access only and transmission charges shall continue to be charged as per the PoC concept. BG should be a nominal amount, say 10-15% of cost of Network expansion. Planning transmission system to give assured direction in all direction would be

ultimate objective but it may take some time and therefore has to be done in a phased manner.

- (vii) Sh. Shanti Prasad: GNA is appropriate as in other concept also practically there is no compensation for stranded capacity. Exit charges to be two year's POC charges. In some cases, depending on margin available in transmission system, to give assured access in all direction may be feasible initially (i.e. at the time of commissioning of generating station). But in all cases, it may not be feasible. Congestion so experienced will lead to system augmentation and thereafter (say in 2-3 years' time) access in that direction may become feasible.
- (viii) KSEB: GNA proposed by CEA may be adopted for transmission system planning. However, KSEB does not agree with the concept of sharing the transmission charges based on the GNA as the proposal is against the provision in the National Electricity Policy and Tariff Policy. There shall be penalty to generators and drawing entities provided the actual injection/ drawl less by 15% from the GNA sought for. The excess drawl/ injection may be charged at short-term PoC charges. BG for GNA should be fixed as the amount corresponding to the NPV of expected transmission charges for 5 years from COD.
- (ix) APP: GNA is a better option. However, the formulation suggested by CEA needs substantial changes to address many of the issues that have been flagged in the Staff Paper. Transmission tariff in GNA should be as per National Electricity Policy and Tariff Policy.

- (x) Dhariwal Infrastructure: have expressed that they were not aware of GNA. BG should be 10% of project cost and exit charges should be five years revenue. It is not possible to give assured access in all directions.
- (xi) TATA Power: GNA appears to be the right way forward. The central grid strengthening needs to be in sync with the state grid system strengthening. We suggest that CEA may be given the responsibilities to co-ordinate with the generator / buyer in getting their maximum injection / drawal for future period. It would be possible to plan transmission system to give assured access in all directions provided transmission planning is not guided strictly by the projected demands and builds in adequate redundancies.
- (xii) NTPC: It does not include the State Network Access. It is not clear how the system strengthening will take place in GNA. Further, GNA calls for new pricing methodology and new regulations.
- (xiii) MPPKVNL - Till clarity on issues on GNA raised in the Staff Paper, Alternative-I should be followed. BG for exit or scaled down GNA could be obtained for the full stranded capacity with the condition that in case of effective transfer to other party, the encashed amount shall be appropriated till the date of transfer and balance would be refunded to the defaulting entity. Assured access in all direction is possible the cost of stranded capacity.

- (xiv) POWERGRID- Alternative-I with drawal based planning delinking with requirement of generators, backbone system be planned as grid strengthening schemes.
- (xv) Thermal Powertech: 3rd Amendment to POC + Amendment in Connectivity Regulations will bring same effect as proposed in GNA. Transmission pricing may be usage based on PoC and for access some suggestions to be included in the Connectivity Regulations to give the same effect as of GNA.

Question No. 10: Transmission Planning:

- (a) How Transmission planning in the country needs to be reviewed under present condition to take care of future need of robust transmission system?**
 - (b) Whether there is need for a separate Regulation for transmission planning to make it more participative?**
 - (c) Whether transmission planning should mandatorily make margins available for short term power market?**
 - (d) Whether transmission system planned by CEA /CTU need to be adequately explained from cost benefit point of view?**
 - (e) Is there requirement of making submission of information related to transmission planning legally binding?**
- (i) MB Power, IEX, Jindal Power, M.P Poorvkshetra Vidyut Vitran, NTPC, POSOCO, Simhapuri Energy Limited and TATA Power- There is a need for regulations on

transmission planning to make planning more participative and accountable.

- (ii) GUVNL and Dhariwal Infrastructure - There is no need for regulations on transmission planning.
- (iii) GRIDCO has stated that the benchmark for performance parameters for ISTS should be fixed and the same should be carried out on mock exercise basis.
- (iv) Dhariwal Infrastructure: Transmission plans are to be reviewed by the CTU and CEA jointly. Since short term transactions are growing, it cannot be categorised as occasional. Hence, there is a need to make margins for it in the transmission planning. Else, it would always endanger the grid.
- (v) Essar Power: Generators are being burdened with excessive risk, in planning stage both the Generator and Beneficiary should be made partner and should share the risk.
- (vi) GUVNL: Transmission planning should be forward looking factoring the best, average and worst scenario. Margins in transmission system will facilitate the real time adjustments through short term power market. The margin should facilitate 15% of power requirement through short term market. Stakeholders should know the cost-benefit of transmission system. It is not required to make submission of information related to transmission planning legally binding since information relating to transmission planning is based on forecast and entailing many variables. Actual data/scenario may vary. Therefore it is indicative and most likely but cannot be made sacrosanct.

- (vii) IEX: Transmission planning should be done under regulatory oversight. At least 30% margin should be mandatorily available for short term power market. For optimum development of the transmission system, CEA /CTU need to adequately explain from the cost benefit point of view. Submission of information related to transmission planning should be made legally binding.
- (viii) Jindal Power: Transmission planning should be based on proposed addition of generating capacities and projected load growth. Submission of information related to transmission planning should not be made legally binding however the planning information should be transparently available to all stake-holders.
- (ix) M.P Poorvkshetra Vidyut Vitran: For future need of robust transmission system, correct declaration of drawal capacity by drawee entities and adhering to COD by generating Company would be the basis of robust planning. The present proposal of declaration of drawal capacity and injection capacity 5 years in advance on yearly rolling basis would pave roadmap for proper transmission planning. Transmission planning should not mandatorily make margins available for short term power market and STOA should continue to be managed through the available margin. This would ensure optimum utilization of transmission network. At present, there is no requirement of making submission of information.
- (x) MB Power: We need to build 'super highways' for bulk transmission of power across the Regions/States. The time

horizon for such highways should be not less than 15 years in respect of load projections. The intra-state transmission plans need to be coordinated with such plans and should be designed to deliver power to states/ load centres. A design margin of 5% over the projected demand towards data inaccuracies and another 5% towards other unknowns. Regarding submission of information, it should not be made binding but the entities providing the information should be made accountable towards the same.

- (xi) NTPC: 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. 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. 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. Since transmission planning is a continuous process, only data/information sought before actually execution of network expansion to be legally binding.
- (xii) POSOCO: Planning of Transmission System should be done in following time horizons (i) CEA may formulate perspective transmission plan for inter-State transmission

system as well as intra-State transmission system for 20 year time horizon and (ii) CTU may formulate “Master Transmission Plan” for inter-state transmission system of 5 year time horizon on rolling basis (iii) cost benefit analysis of new transmission system planned should be made public.

- (xiii) Shri Shanti Prasad, Ex-chairman, RERC: Transmission system is designed considering standard voltage levels, standardised conductors and standard rating of transformers. This will give built in margin for short term transaction. 'N-1' contingency, considered in transmission system design, will give additional margin for short term transaction when there is no outage. Cost benefit analysis may be part of planning and should be reported. Where, it is not possible (for example, reactive compensation, metering, communication, etc.), Least cost criterion should be the governing criterion.
- (xiv) Simahpuri Energy Ltd: System demand forecast/information about load centres also need to be provided by utilities to be considered for transmission planning instead of LTA applications alone. Transmission planning should mandatorily make margins available for short term power market as it is a need of the hour since some of the contracts already executed in the short-term are stranded for want of transmission corridor. Hence, margins are needed but possibly at slightly higher levels of transmission charges made known well in advance. Transmission system planned by CEA /CTU need to be

adequately explained from cost benefit point of view for optimal planning and utilization of transmission assets.

- (xv) Thermal Powertech: Considering the uncertainty in the power sector growth, inaccurate demand projections, large number of grid users, and additions of Renewable generation with Grid in lesser time, Transmission system development is not keeping pace with the actual requirement of Transmission system, thereby leaving the network severely congested. Lack of intrastate transmission system for accessing power from rest of India via Interstate transmission system is leading to network congestion and is making the inter-State transmission system investment unutilized resulting in power parity between the regions, which is against Act'2003 and tariff policy. For holistic growth & improvement of the sector, even the Intra-State transmission planning and development should be envisaged with coordinating with CTU/CEA.
- (xvi) TATA Power: Creating redundancy in the system is essential for creating a futuristic transmission system for longer horizon. If the system is being developed with a redundancy of 30- 35%, requirement for such additional margins for specific nature of transactions may not be there. The Transmission System planned by CEA/CTU need to be adequately explained from cost benefit point of view. A detailed information exchange is necessary between planning agencies and various participants of the power

system. This will assist planning agencies to anticipate fair load, generation and usage of ISTS in large time horizon.

Question No. 11: Utilization of Congestion charges

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

(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?

- (i) APP: As the basic purpose of the idea of using this as a grant or soft loan would be to reduce the incidence of transmission tariff, best is to utilize it directly for transmission tariff reduction by way of adjusting within the pooled transmission charges.
- (ii) Essar Power, Dhariwal Infrastructure, IEX, PXIL, Shri Shanti Prasad: Congestion charges collected from ISTS licensee should be utilised as loan to fund new projects to relieve congestion.
- (iii) GRIDCO: If CTU will be agreed to take remedial measures to relieve congestion at their own cost, as to be suggested by the CAC Sub-Committee, then only the congestion charges should be used to reduce the long term ISTS transmission charges. Otherwise, the same can be used for relieving congestion by employing external consultants for

higher modern technology-based solution with strict supervision of a CERC appointed high power committee.

- (iv) GUVNL: Congestion charges should be appropriated towards reduction of Long term ISTS transmission charges.
- (v) Jindal Power: Congestion charges may be refunded to exchange participants.
- (vi) KSEBL: The congestion amount collected from the utilities may be segregated region wise and the amount collected from each region may preferably be utilized for developing the transmission system to relieve the congestion of that region i.e. the congestion and e-bidding revenue collected from SR utilities may be used to create transmission infrastructure to relieve the congestion of SR.
- (vii) MB Power and Simhapuri Energy Limited: Congestion charge should be adjusted against the long term transmission charges.
- (viii) NTPC: Congestion is a natural and unavoidable phenomenon. It should be managed by scheduling and control and not by applying charges.
- (ix) POSOCO: Any amount received through e-bidding and congestion revenue should be adjusted towards transmission charges to be paid by all DICs on quarterly basis. The market participants may raise the issue that it should be returned to them on one to one basis, but if it is done, it will distort the signal which is intended to be captured through congestion. As all DICs who are long term customers of the transmission system will get back some money, the acceptance for future transmission

projects will be easier. The amount lying in the Power System Development Fund accrued on account of Congestion revenue account together with interest earned thereon may be utilized for development of transmission corridors necessary for alleviating congestion.

- (x) TATA Power: The congestion charges should be used for lowering of transmission charges. However, if the same can't be considered then these should be utilized for creation of specific transmission assets for relieving the congestion instead of relieving the long term ISTS charges. This money may be treated as loan with concessional interest of 2-3% lower than SBI PLR to avoid any possible misuse of such money when treated as grant besides making available such funds on a regular basis for developmental works.

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**
- (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.**
- (i) Adani Power, Association of Power Producers (APP), Jindal Power, MB Power, NTPC have opposed the idea of allowing

participants of Power Exchanges to participate in e-bidding for transmission corridor and reserving corridor for power market with all participant of Power Exchange sharing the transmission charges of reserved corridor.

- (ii) M.P Poorvkshetra Vidyut Vitran has supported the idea of allowing participants of Power exchanges should be allowed to participate in e-bidding for transmission corridor but opposed the idea of reserving corridor for power market with all participant of Power Exchange sharing the transmission charges of reserved corridor.
- (iii) APP: It seems a clear discrimination among the participants those who are on bilateral platform and the participants who are transacting on Power Exchange. In the present scenario allocating the corridor to the participants of collective transactions without knowing the point to point transaction of power flow would be a game.
- (iv) Dhariwal Infrastructure: Reservation of corridor is not recommended. The participants may e-bid for the corridor to gain utilisation rights.
- (v) Essar Power: A certain quantum of corridor should be reserved for power market with all participant of Power Exchange sharing the transmission charges of reserved corridor as this will reduce the price burden of Congestion borne largely by participants in collective transaction.
- (vi) GRIDCO: There is no clear picture in the Staff Paper on the improvement of Inter-regional power transfer capability of the ISTS, once the above high capacity transmission corridors will come into full operation and use.

- (vii) GUVNL: The transaction of power keeps varying from day to day therefore keeping certain quantum of corridor reserved for Power Exchange will not be an optimal solution. Hence the Power Exchange participants should be allowed to participate in the e-bidding for transmission corridor.
- (viii) IEX: It would be appropriate to reserve inter-regional corridor for the power exchanges and a premium may be charged from the exchange participants towards such reservation.
- (ix) KSEBL: Instead of day ahead collective transactions, term ahead or month ahead double sided closed bid auctions can be implemented for collective transactions in power exchange, by availing the transmission capacity available for short-term.
- (x) PXIL: Against E-bidding mechanism and proposed capacity allocation.
- (xi) POSOCO: The proposed capacity allocation mechanism for Power Exchange participants may be prone to market manipulation and gaming. In case of under-utilization of corridor capacity, the under-utilized capacity may have to be redistributed amongst the Power Exchanges. This would lead to a process involving multiple iterations.
- (xii) Shri Shanti Prasad, Ex-chairman, RERC: As all participant of power exchange will not be providing for the capacity creation partly funded by registration fee, so transmission corridor for firm power transfer / LTA may not be subjected to e-bidding.

- (xiii) Simhapuri Energy Ltd: If the participants of power exchanges booked the corridor in e-bidding there is a drawback of stranding the transmission capacity if their volume bid in the exchange does not get cleared.
- (xiv) TPTCL: Market structure should not be altered. In case this proposal is being considered then to maintain a level playing field, traders may also be allowed to book the transmission corridor without the identified buyer / seller on both sides.

CHAPTER-4

ISSUES RAISED BY INVITEES AND THEIR SUGGESTIONS

4.1 Introduction

During the meetings of the Committee, Ministry of Power (MoP), CEA, CTU, POSOCO, IPPs and individual power system experts were invited separately to present their views on the issues presently being faced in respect of transmission planning, LTA, MTOA and related issues as well as on the issues raised in the CERC Staff Paper. The invitees recounted the issues being faced in transmission planning and also gave suggestions in regard to some of the issues for consideration of the Committee.

4.2 Issues raised by Invitees during the Committee meeting

4.2.1 Issues raised by Transmission Planners

The System Planners i.e. CEA and CTU and the System Operator, POSOCO reiterated the issues raised by them vide their written comments on the Staff Paper.

4.2.2 Issues raised by System Operator

The System Operator also raised some specific issues regarding Transmission Planning as listed below:

- (a) Whether transmission planning in a vast country like India should be centralized or decentralized?
- (b) Economics is not considered in transmission planning.

- (c) Reliability, risk mitigation, fuel, market, etc., are not factored in transmission planning.

4.2.3 Issues highlighted by MoP:

- (a) Transmission system planners can draw reference from other infrastructure sector to ascertain the basic transmission highway.
- (b) Intent of building transmission corridors should be stated upfront i.e. certain transmission corridors are essential in nature and certain corridors are for evacuation of particular generation.
- (c) CTU is facing a lot of difficulty in getting a system approved in the Standing Committee as the stakeholders are showing reluctance because of additional transmission charges. The Commission should give immediate decision for the projects which are essential in nature and constituents are not willing to give concurrence.
- (d) There should be measurement of efficiency of planning either through pricing, utilization or at planning level.

4.2.4 Issues raised by IPPs:

- (a) IPPs are unable to find beneficiaries for long-term procurement of power.
- (b) Feasibility of long term PPA when State DISCOMs are not coming forward to sign PPA for procurement of power on long-term basis.

- (c) Integration of power generated from renewable sources should be considered while planning of transmission system.
- (d) Transmission planning for STOA/power exchange/ MTOA should also be carried out.
- (e) Transmission Charges are paid by Generators for LTA to target region but no priority is accorded to them in scheduling.
- (f) In case of Force Majeure with generators a generator may wish to delay commencement of LTA or relinquish of LTA.
- (g) Generator should be allowed to transfer LTA in part or full to any other interested party.

4.2.5 Issues raised by DISCOMS, Open Access Customers, Power Exchanges:

- (a) DISCOMs are facing problem of congestion in getting MTOA and STOA.
- (b) Open Access Customers who want to procure power from the market are finding it difficult to get power on regular and reliable basis due to congestion.
- (c) Power Exchanges, which are transparent platforms for transactions, are facing problem of congestion more frequently.
- (d) Transmission planning for integration of renewable energy is also important to connect renewable energy sources at 33kV & below.
- (e) Congestion management under the proposed GNA approach of transmission planning.

- (f) Issues with accurate Demand forecasting by DISCOMs.
- (g) Inability of STU to furnish import/export data for GNA when DISCOMs in the State introduce load restriction and the actual import is less than GNA.
- (h) Impact analysis of PoC charges.
- (i) Planning of transmission system to avoid loop flows.
- (j) Clear demarcation responsibilities among among DISCOMs, STU and SLDC for load forecasting within the State.
- (k) Does GNA apart from connectivity involve commitment to payment transmission charges by the generator? Does it also include payment of drawl GNA charges when the PPA is not firmed up?
- (l) Fixing benchmark levels for efficiency, reliability and congestion limit for the ISTS.

4.2.6 Issues raised by stakeholders at MoP meeting

DISCOMS/STUs/State Governments raised following issues in regard to proposed GNA as part of comments to CERC Staff Paper/meeting taken by Secretary, Ministry of Power on 18.8.2015:

- (a) Transmission system developed on 360 degree basis may have consequences in the form of overbuilding of transmission capacity, redundancy, burden of transmission charges without actual usage, etc.
- (b) Risk of force majeure to generator and incidence of transmission charges on beneficiaries/ drawees.

- (c) To handle issues arising due to actualization of the forecasted scenario is difficult in wake of power sector issues like delay in getting statutory clearances, fuel issues, liquidity problem, behaviour of Open Access consumers, captive generators, financial health of DISCOMs, etc.
- (d) How will the STU provide data in view of dynamic and uncertain position in regard to Open Access?
- (e) Assurance of access commensurate with GNA.
- (f) Aligning Transmission Pricing mechanism with distance, direction and quantum of flow as envisaged in the National Electricity Policy and the Tariff Policy.
- (g) Payment liability as per GNA may induce intentional under declaration of Drawal GNA by DISCOMs/ STUs.
- (h) Financial implications of GNA have not been indicated in CEA's proposal. There is no clarity about the impact of transmission charges to be paid to CTU.
- (i) GNA is based on maximum demand. However, in case of Punjab, demand is at maximum only during 3 months of paddy season and rest of the year, demand remains very low. Whether transmission charges corresponding to maximum demand are to be paid throughout the year or GNA could be reduced for 9 months, when demand is low?

4.2.7 Issues raised by Power System Experts:

- (a) Reliability & security is the most important criteria for power system which must be taken into consideration

during all phases of power system planning, design and operation.

- (b) Transmission planning approach should be hybrid i.e. combination of both deterministic (and heuristic) and probabilistic.
- (c) The present planning process does not take care of the requirement of capacitive compensation in EHV system to take care of reactive power needs of the transmission system.
- (d) There should be adequate capacitive compensation to allow EHV system to operate up to thermal limits and beyond thermal limits during emergency and also to account for varying operating conditions (temperature, wind speed, etc.).
- (e) Non-availability of power flow controllers like phase-shifters, HVDC or FACTS controllers for controlling the power flow during contingency period.
- (f) The present planning practice considers loading the line to thermal limits or stability limits (less than 30° angular separation) in case of N-1 or N-1-1 contingency thereby restricting the loading of the assets to less than 50% of thermal limits and in some cases close to SIL limit. This results in network loading just above the SIL limits during peak load operation (which is less than 5% of the time) and in other periods, the lines are loaded below SIL resulting in over-voltage in the system and on many occasion, many EHV lines are kept open to limit the over-voltage.

4.3 Suggestion made by the invitees

4.3.1 Suggestions regarding Connectivity:

- (a) CEA has stated that Connectivity should not be given with ISTS and also with STU System without payment of Connectivity Charges and there should be provision of disconnection, if GNA is relinquished by generators. CEA has also stated that it is STU and not DISCOM which should be allowed to get connected / and given GNA with ISTS.
- (b) CTU has stated that Connectivity should be given to entire quantum of Installed Capacity minus auxiliary consumption and it should not be free. CTU suggested that grant of connectivity should be accompanied with 25% injection charges. They also opined that Connectivity should be dispensed with, and LTA must be applied for the entire quantum of the installed capacity minus auxiliary consumption. However, CTU stated that if the Committee feels that it is necessary to retain Connectivity as a separate product to facilitate generation developer in achieving financial closures, then the grant of connectivity ought to be subject to applying LTA within a definite time period. CTU stated that development of connectivity/dedicated lines should be under the scope of generation developer. CTU was also of the opinion that DISCOMs should be barred from seeking connectivity directly to the ISTS.
- (c) Power System Experts stated that Connectivity is a desirable agreement which is required at the time of project

finalization and it helps in timely synchronization of generators to the grid. They also stated that Connectivity system is required corresponding to installed/commissioned capacity and is required ahead of commissioning of generating units and phased according to transmission elements. They stated that Connectivity system up to pooling point is exclusively utilized by the respective generating station(s) and Section 10 of the Act assigns this as a duty of generating company to establish, operate and maintain this system (not only dedicated transmission lines but also tie-lines and substations). They stated that Connectivity should remain as a separate product because it is a statutory requirement for open access as per the Act and the CERC Connectivity Regulations and therefore, it cannot be tied up with Long Term Access. They also stated that Connectivity should be given for full synchronized quantum and it should not be free. They further opined that all new connectivity/dedicated lines should be built, operated and maintained by the generators at their own cost.

- (d) Association of Power Producers stated that transmission tariff for the existing connectivity lines(up to first connection points) should not be pooled and it should be assigned to the specific generator or specific long-term beneficiaries. They further stated that Connectivity taken by generator without any access is of no use. However, Connectivity is essential for financial closure of the project and therefore, a generator should be given at least 3 years,

which is also quite reasonable, to apply for LTA/GNA after grant of Connectivity.

- (e) PCKL suggested that generation seeking GNA to the grid should be responsible for construction of dedicated transmission line from switchyard of the generating station to the ISTS grid point either under section 10 of Electricity Act-2003 based on Technical Study subjected to approval in the Standing Committee Meeting. Further, life of the project in case of generation project is 25 years whereas life of the transmission project is 35 years. Since, there is mismatch in recovery of revenue to developer, this issue needs to be addressed.
- (f) GETCO has suggested that if generation seeking GNA to the grid should be responsible for construction of dedicated transmission line from switchyard to the ISTS grid point identified by CEA/CTU for grant of GNA, the present provisions of 500 MW or 250 MW to be undertaken through coordinated planning needs to be deleted.

4.3.2 Suggestions regarding Transmission Planning:

- (a) CEA stated that the concept of GNA brings a new approach to transmission planning as generators will not have to specify their drawal points and drawee entities will not have to specify injection points. In GNA, generators are mandated to take GNA corresponding to their ex-bus capacity (other than captive) and utilities are required to assess transmission requirement for GNA at least 4-5 years in advance. CEA further stated that GNA is a Transmission

Service contract which segregates between 'Energy' and 'Transmission Service' contracts. It provides flexibility in energy procurement. It is futuristic and can handle Long, Medium and Short term PPAs or any market mix, in whatever way the market may tend to evolve. It is also a mechanism to share uncertainties and has potential to optimize transmission system. Further, in GNA, STUs have a key role to fulfil as defined under Section 39 of the Electricity Act, 2003. CEA also added that the GNA agreement with generators/drawing entities could become the driver for investment in transmission system for implementation of transmission corridors.

- (b) MoP suggested that the transmission planners can draw reference from other infrastructure sector while planning transmission system to ascertain the basic transmission highway needed for evacuation of power and also the intent of building such corridors should also be stated upfront in the final regulations i.e. certain transmission corridors are essential and certain corridors are for evacuation of particular generation evacuation. MoP further suggested that there should be measurement of efficiency of planning either through pricing, utilization or at planning level and the planning agencies should indicate the assumptions and the output they are looking for. MoP also requested that that the Commission should expedite decision making for the projects which are essential in nature and for which the constituents are not willing to give concurrence.

(c) POSOCO suggested that probabilistic approach of transmission planning needs to be adopted for planning considering low probability high impact events and public good of transmission planning need to be factored in while planning transmission system. Further, economics is the objective function and reliability is the constraint. The objective function is not taken into consideration currently. Also, Transmission Planning should factor-in uncertainties stating the confidence level and for which data from past should be used. POSOCO also suggested to the Committee that in a vast country like India, centralized planning is not going to work. Therefore, there is a need for decentralized planning both from the bottom and the top. There is also a need of faithful assessment of requirement of transmission system by utilities for which the states are required to indicate their import/export from ISTS and their self generation. POSOCO further suggested that at the planning stage itself, there should be a trajectory of loss, percentage of transmission charges & loss and percentage of congestion which should be demonstrated so that the constituents can decide whether they prefer to have more losses in the system or a new transmission line. POSOCO suggested that we all should decide whether we should plan a congestion free system or certain amount of congestion should remain in the system as congestion free system is very costly and there would be some congestion if the market is vibrant.

- (d) Power system Experts have suggested that Transmission Planning should consider various dispatch scenarios based on first dispatching long-term PPAs based generation and then dispatching merchant capacity in all probable directions so as to arrive at full requirement of the transmission corridors. Drawal GNA should not be force-increased to match injection GNA and some increase in Drawal GNA should also be considered. They suggested that LTA and MTOA were necessary for the transmission planner a couple of years back when the national grid was not strong. Today the national grid with Ultra High Voltage (UHV) back bone is fairly robust and it is certain that every MW generated finds a customer in a scenario of growing load. Hence, making LTA mandatory during project approval stage is not important. Further, overloading and congestion in the system have been shown as a concern that transmission planning is becoming difficult because of uncertainties resulting into congestions which may not be entirely correct because in a planned network, congestion could be for short time and technical solutions like use of Phase Shifting Transformers (PSTs) can handle congestion.
- (e) Power System Experts suggested line loading should be based on realistic picture of conductor temperature and wind speed during peak load period.
- (f) It was felt that present planning process does not appear to take care of reactive power compensation (both inductive and capacitive). It was suggested that capacitive and inductive compensation referred to voltage profile of the

EHV system should enable it to operate it up thermal limit and beyond. It was suggested that planning of EHV system should also consider capacitive compensation in the system and there should be adequate capacitive compensation to allow EHV system to operate up to thermal limits and beyond thermal limits during emergency and also to account for varying operating conditions (temperature, wind speed, etc.).

- (g) Most of the international systems are now designed for 30% stability margin (corresponding to angular separation to be 45 degrees) rather than 50% stability margin (angular separate to be 30 degrees).
- (h) The relationship between line length and P/SIL on per unit basis gives the fair indication of surplus /deficit reactive power. When the loading of the line goes beyond the specified limit, the receiving end would need voltage support to ensure desired loadability.
- (i) Power System Experts have also given overview of practices followed internationally to increase in transfer capability of transmission system- Power Flow Control in NGC, England:
- (j) NGC's broad approach to optimize the transmission system is to ensure maximize the utilization of the existing system in the operational phase as a part of asset management.
- (k) As a practice dynamic voltage support is generally kept at 50% passive voltage support. The dynamic support in the form of SVC and FACTS devises become active only during post outage conditions.

- (l) To improve real power sharing in the meshed network, 15 Quadrature Boosters or Phase Shifting Transformers or phase cycle regulator of passive type have been installed at both the 275 kV and the 400 kV voltage levels with ratings ranging from 750 MVA to 2750 MVA to ensure adequate power sharing in the meshed network.
- (m) In order to maintain voltage profile, Capacitive compensation devices have been installed at 400kV, 275kV and 132kV.
- (n) An increase of transfer capability is envisaged in many countries through
 - (i) Upkeep of existing lines and modernizing maintenance practices
 - (ii) Additional Reactive power compensation to account for reactive power consumption of the lines
 - (iii) Phase shifters for balancing power flow between the AC corridors and Series compensation on medium & long lines to reduce angular separation
 - (iv) Upgrading the conductors with High Ampacity of critical lines to increase flow gate
 - (v) In addition, emergency loading beyond thermal limits are permitted as per IEC standards (along with SPS if necessary on critical lines) to permit overloading during contingencies for a short period of time.
 - (vi) In order to take care of system uncertainties faced by National Grid, England, re-locatable Dynamic Compensation Systems are installed which enhanced system performance. As on date, 12 re-locatable SVCs

(RSVCs) have been installed as part of a planned program to meet these changing system needs.

- (o) Association of Power Producers suggested that transmission system should be flexible to handle seasonal variations. He gave example of Punjab where extra power is required for irrigation and related issues during paddy season (3 months approximately) and for rest of 9 months demand is normal and Punjab pays for fixed charges for the power tied up under long term for the 3 months demand. He stated that LTA/MTOA/STOA should be subsumed in GNA.
- (p) Meghalaya Power Transmission Corporation Ltd (MePTCL) has stated that regarding Transmission Planning, a comprehensive scheme was developed together with CEA and POWERGRID for strengthening of the intra-state transmission system of Meghalaya. The scheme was finally decided to be funded jointly by the Government of India and World Bank under the North Eastern Region Power System Improvement Project (NERPSIP) in tranches. Since the comprehensive scheme will be taken up in tranches, due to financial constraints it may take time for the intra-state transmission system of Meghalaya to catch up with the GNA concept.
- (q) KPTCL has stated that they are in agreement with GNA. For GNA, the State will provide the projected quarterly peak import/export requirement for the next 5 years to CTU. STU will furnish the data after consolidating the figure from each DISCOM of the state and such data

should be provided on the annual rolling basis. There should be a provision to revise the quantum at least after one year for every midyear (i.e., 2 and a half year) quantum on rolling basis since four year ahead is difficult.

- (r) PCKL and KPTCL have stated that necessary provision should be there to re-schedule the GNA granted under GNA mechanism to Medium Term or Short Term transaction within the Regional beneficiaries (DISCOMs) including Open Access customers in case of un-utilization of GNA granted. Further, in case of un-utilization of Inter Regional Transmission links the same can be re-schedule to other Regional beneficiaries under Short Term basis subjected to availability of margin with approval of NLDC on case to case basis. They have suggested that since minimum 4 years from the date of request for GNA is necessary for putting up the required transmission system infrastructure, hence any early readiness prior to 4 years from the Seller whose Generating Station is connected to ISTS should be allowed to transact based on the certification from CEA / CTU subject to approval in the Standing Committee Meeting and it should be made mandatory. However, an early readiness to supply power within the state is subject to the approval of the state commission as per the Competitive Bidding Guidelines. Further, access to ISTS should be commensurate strictly as per the provision of Standard Bid Document / Regulatory Provisions.

- (s) GRIDCO stated that before implementing GNA, the recommendations of the CAC Sub-Committee on congestion in transmission need to be implemented. As mentioned in the report the capability of ISTS to transfer power is yet to be ascertained by CTU and moreover, the stranded Assets in ISTS is yet to be quantified. Hence, it may be prudent to implement the GNA mechanism after the transfer capability of the ISTS is confirmed and the stranded assets quantified, so as to comply with the mandate of the Electricity Act-2003 in terms of efficiency, economical use of the resources, good performance, optimum investments and consumers' interest. Issues such as non-discriminatory Open Access, under-utilization of Assets, payment liability falling on other users, in case Generator is not able to find beneficiary, 360 degree dispersal of power; limiting the access up to GNA quantum, relinquishment charges have not been addressed under GNA Mechanism. Further, the GNA Mechanism does not speak out on the issue of sale of surplus power by the States for which even if the states will declare their injection GNA as there is no prescribed mechanism for such sale. GRIDCO stated that all the activities pertaining to GNA mechanism should be prescribed simultaneously in toto.
- (t) GETCO stated that GNA concept will result in development of redundant transmission network at the cost of beneficiary States since the load demand is very dynamic and very difficult to predict. The network development will

be disproportionate akin to 2007 when the network was planned for upcoming projects in Eastern Region without beneficiaries and the situation has further aggravated with more and more generators facing problem on account of non-identification of beneficiaries. Further, The States need to specify their maximum power drawl requirements as required GNA quantum for drawl. Further, the GNA (drawl/injection) has to be assessed at least 4-5 years in advance. The STU cannot specify such quantum since the drawl quantum of certain embedded entities opting to buy / avail power from outside the State under STOA / MTOA is not known in advance. The STU can forecast the GNA-Drawl on the basis of long term power purchase contracts entered by DISCOMs and other embedded entities for buying power from outside the State through utilization of ISTS. Further, Gujarat has significant quantum of renewable generation like wind, solar etc. which are unpredictable and the drawl or injection quantum over the ISTS is going to vary depending on the renewable generation, which is also presently not in line with the scheduling mechanism for conventional sources.

- (u) ERPC stated that GNA approach is very useful for Transmission Planning process since it offers a lot of flexibility to all the stakeholders for sell or purchase of power. Further, Transmission Planning based on the concept of GNA should be done in correlation with the timely implementation of transmission project and overall cost implication on the stake holders. In the event of

under-utilization of total granted GNA by an entity due to reasons not attributable to that entity, it will have financial implication on that entity which will be ultimately passed on to the end consumer. Hence for under-utilization of corridor due to any force majeure condition, the concerned entity should be compensated for it. Also, mismatch between commissioning of Generating Station and implementation of Transmission project may have severe cost implication on the generator and has to be avoided.

(v) TPDDL stated that GNA is definitely a new and welcome concept and can lead to better network planning provided some flexibility are provided in the GNA regime. Following issues in GNA need to be addressed:

- (i) It is not practical to assess the GNA requirement for such a longer tenure due to a number of uncertainties associated in the demand forecast.
- (ii) GNA limit revision for any particular year should be permitted at least two years in advance.
- (iii) Utilities also need to have accurate information on upcoming RE generation projects and there Connectivity with the GRID (CTU or STU level) to assess that how much quantum of RE power has to be imported through CTU and how much can be generated within state itself.
- (iv) GNA should be limited only to the extent of utility's requirement from LTA with a firm payment liability towards the declared GNA with a margin of + 30% to accommodate the STOA/MTOA transactions to

account for seasonal variations and sudden Demand/Supply variations without any additional penal charges for utilization of the Transmission network in the short term/Medium Term.

- (v) GNA has to include all the modes of network access by a utility such as short term, medium term and long term. It would be fallacious to estimate the quantum of power to be purchased by a utility under these different access types 8-10 years down the line.
- (vi) In case of Reallocation/Surrender of power allocated to any utility to any other utility, GNA liability of the concerned utility should also be shifted to the state to whom the power has been reallocated.
- (vii) GNA liability should be transferrable to neighbouring states in a particular region if a trend of regular GNA violation is seen by any particular state.
- (viii) While planning for transmission network both at STU or CTU level, representatives of Distribution Licensee/Utilities should also be invited in the validation committee along with concerned STU representatives.
- (ix) DVC stated that the up-coming generators of DVC have long term PPA with the beneficiaries of other states. But, some of the beneficiaries do not comply with the TSA requirement with CTU. Meanwhile, the generators have declared COD but no schedule is made to those erring beneficiaries due to non-availability of clearance from CTU. If, GNA is introduced and DVC

apply for GNA injection for the whole generation capacity, then it is apprehended that DVC may be losing commercially due to GNA injection cost without schedule to beneficiaries. DVC suggested that if long/medium term PPA is made tripartite (Generators + beneficiaries + CTU) in lieu of bipartite between Generators and beneficiaries, the above problem can be avoided. Further, when beneficiaries surrender long term share, provision of GNA injection revision is there. Such revision needs to be immediate on application when share is surrendered by the beneficiaries to save generators from commercial point of view.

4.3.3 Suggestions regarding Recovery /Sharing of Transmission Charges:

- (a) MoP stated that the issue is how we want the total power procurement to be done by a utility i.e. what should be the percentage for long term (say 70%), medium term (say 20%) and short term (say 10%) procurements in the basket of total power procurement by the utility. This issue will also be affected by the policies formed by the Government of India, technical aspects, etc., and pricing of transmission system will have to be done accordingly. Looking at current trend in short term prices and long term prices it should not happen that utilities want to procure more power on short term basis than procurement of power through long term thereby hampering transmission

system development. MoP suggested that we should make long term procurement pricing cheaper than medium term and short term procurement.

(b) CEA suggested that in GNA transmission charges would be determined by the GNA quantum and PoC rate for that point. POC rate is given in Rs. / MW at the point of injection/drawal. Any under /over recovery will be adjusted in proportion to first bill. The above rates will be applicable for transactions up to GNA quantum. In GNA, injection/ withdrawal beyond GNA attracts enhanced PoC charges on the excess quantum (say ~ 400%) to encourage assessment of GNA requirement at least 4-5 years in advance. The broad Transmission Pricing Mechanism suggested by CEA is as given below:

- (i) Transmission rates to be calculated considering GNA quantum and GNA holder would pay POC injection or drawal charges as the case may be.
- (ii) Generators/drawing entity will pay GNA charges from the contracted date or the actual date whichever is earlier. Provisions for delay in creation of sufficient transmission capacity would be needed in regulations.
- (iii) Any power transfer beyond the GNA capacity may be entertained only for STOA service at a premium rate.
- (iv) The design for implementation of GNA should be such that, it encourages the customers to apply for LTA. For this, Multi part tariff may be implemented as proposed below.

- (v) While recovering transmission charges, some part should be recovered on the basis of GNA and some part from LTA/MTOA granted. The customers transacting through short term transactions within GNA quantum of the State would thus pay charges for full year. Thus, those who are involved in the transactions through short term would effectively pay more per unit of energy compared to the long term.
 - (vi) While planning the transmission system based on GNA, 15% to 20% margin may be kept for future growth. This provision may be included in the policy/regulation.
- (c) CEA has also suggested a multi-part tariff mechanism for ISTS services as given below:
- (i) The total annual inter-State transmission charges may be recovered in two parts, one part being 'Fixed Component (FC)' and the other 'Variable Component (VC)'. The FC shall be in proportion to the GNA sought to account for the investment made in creating transmission capacity to serve this GNA. The VC may be linked with actual commercial arrangement (i.e. PPA whether Long, medium or short term) in which, preference may be given for point-to-point LTA transactions over the MTOA/STOA/PX transactions. A broad scheme of recovery of transmission charges under this mechanism is given below. The percentages/parameters associated with various components are indicative and can be improved upon.
 - (ii) Suppose we need to recover Rs 100 crore per month during a particular quarter, then the FC and VC can be recovered as follows:

	Rate (formula) applicable	Amount recovered	Applicable for
	Fixed Component (FC):		
(i)	GNA x 75% of POC rate	Rs. 75 crore	All users
	Variable Components (VC):		
(ii)	LTA x 20% of POC rate	Rs. 10-15 crore	Users having point-to-point LTA (within GNA quantum)
(iii)	(MTOA/STOA) x 30% of POC rate	Rs. 10-15 crore	MTOA / STOA users (within GNA quantum)

Note:

- (i) *In above, POC rate is in Rs per MW at the point of injection/drawal.*
- (ii) *Any under / over recovery to be adjusted in proportion to first bill.*
- (iii) *The above rates to be applicable for transactions up to GNA quantum.*
- (iv) *The rate for STOA over and above the GNA to be at premium rate of say 400% in Rs per unit of energy*
- (v) *Further, excess use of transmission (based on Regional Transmission Deviation Account) should be charged at a still higher rate e.g. 6 – 10 times the POC rate in Rs per unit of energy.*
- (vi) *A provision for LTA (target region) may also be kept under VC.*

- (d) CTU has suggested that the charges for STOA should be 3 to 4 times Long Term Access charges since short term customers will use system for only 6-7 hrs in a day whereas Long Term Customers will pay for entire day.
- (e) The System Operator suggested that presently utilities are enjoying reliability for free. Reliability needs to be priced appropriately and it should go up with time. The System Operator also suggested that longer duration contracts need to be encouraged and should be given at lower rate and shorter term contracts should be given at higher rates.

(f) Power System Experts have suggested that transmission charges for the network from pooling point onwards up to one or two next grid stations (shallow connection beyond first connectivity lines) i.e. injection side system developed for specific generating stations/units, should be recovered from those specific generators. Transmission tariff for injection side system from connection/pooling point onwards i.e. Shallow Connection should be assigned to generators only. In case sale of power is tied-up in long-term PPAs with delivery point at generation switchyard, the beneficiaries would replace the generator. Towards above Shallow Connection, 20% of Regional ISTS Charges (excluding inter-regional lines) should be assigned to ISGS within the Region. Transmission charges for network excluding connectivity lines should be pooled on all India basis and 50% of pooled charges recovered as capacity charge i.e. for fixed utilization and 50% of pooled charges recovered as energy charge i.e. variable utilization. Recovery of fixed utilization part should be done through transmission charges on Network Access Capacity (LTA/GNA) and recovery of variable utilization part should be done through transmission charges on energy dispatched. They further suggested that transmission network has been recognized as a market enabler. In passing on the cost of transmission to utility or beneficiary, it is not possible to identify beneficiary accurately. It is possible that CTU recovers 75% transmission charges from identified beneficiary/ demand customer and remaining

25% is levied uniformly to transmission utilities of States (for getting support from central network) as a reliability surcharge. They have also suggested that generators should give GNA equal to their installed capacity and in no case generators should be allowed open access greater than GNA. Further, GNA should not be less than 25 years and upfront normative exit charges should be paid by generators for exit before five years. In case of congestion during scheduling, there should be pro-rata reduction in GNA charge.

- (g) PCKL suggested that any capacity injected or drawn over and above 10% of GNA granted should attract enhanced POC charges.
- (h) ERPC stated that RPCs are currently issuing Regional Transmission Deviation Account for any deviation beyond the approved LTA, MTOA & STOA (injection & drawal) in a 15 min time block. Similarly for variation of actual with respect to GNA granted may be calculated by comparing the actual injection or drawl in a 15 min time block with the GNA granted or the summation of LTA, MTOA & STOA (whichever is higher) and Deviation Charges may be levied on the deviated quantum as is being done now.
- (i) TPDDL stated that methodology of sharing and payment of transmission Charges for different access types (LTOA, MTOA/STOA) needs more clarity under GNA regime. Any penal charges become applicable only if the utility crosses the limit of +30% of the Declared GNA quantum (MW) and incentive shall be provided to the utility who is drawing

lesser MW than its GNA quantum as network is relieved for others.

- (j) Delhi TRANSCO stated that some of the DISCOMs in Delhi particularly BRPL and BYPL are not paying the transmission charges of DTL since long. In case of the responsibility of payment of transmission charges in respect of ISTS based on GNA methodology also is transferred to DTL being the STU in Delhi, it is feared that the responsibility of payment of transmission charges for ISTS is also likely to be not discharged by the DISCOMs. Therefore, the existing methodology i.e. the billing directly to the DISCOMs should be continued in the proposed GNA methodology.
- (k) DVC stated that in the existing POC mechanism for transmission charge recovery, DVC has long term PPA with the beneficiaries with the condition that schedule would be made at Ex-bus of generators and beneficiaries would arrange transmission contract (through TSA) with CTU to evacuate power from Ex-bus generator to drawal point of beneficiaries and payment thereof. DVC suggested that if GNA injection quantum is paid by the generators of DVC to CTU and existing POC mechanism no longer exist then suitable mechanism should be there to recover GNA injection cost through Tariff of generators.
- (l) GRIDCO stated that as per the Sharing Regulations, transmission charges shall be shared among users as per actual usage. However, situation may arise, when the drawl of power is less than the approved GNA quantum.

Therefore, the payment liability mechanism should be prescribed, whether the entity will be liable for payment of the drawal quantum as per actual usage or the contracted GNA quantum. As per GNA mechanism, the GNA quantum will be approved by CTU with necessary terms and conditions and if there would be any deviation to the contractual path(s) for power flow to the drawee entity, the drawee entity shall pay the charges, limiting to charges fixed for contractual path for power flow at the time of GNA approval. As new transmission systems are being set up from generation or fuel hubs of some states like Odisha, it should be ensured that Odisha and like states should not be burdened with transmission charges, even if there is any un-intended power flow. There should also be provision of penalties in GNA Mechanism, if the CTU is unable to provide adequate ISTS infrastructure for injection/drawal of power. There should be simultaneous commitment from the Planning Agencies like CTU/CEA and System Operator for required efficiency, economy, and reliability of the ISTS along with maximum permissible congestion in the interest of consumers.

4.3.4 Suggestions regarding integration of renewable sources of energy generation:

- (a) Power System Experts stated that at present RE is not considered in totality in transmission planning as most of RE would be less during peak load period. However, in future RE would make power flow with unpredictable level

and maximum RE would prevail for few hours (typically 3 to 4 hours in a day) and would have temporal variation. Therefore, RE evacuation planning shall consider emergency rating in power flow rather than treating like conventional power plant. Further temperature should be taken into consideration while planning for wind which comes during morning and evening. They suggested that to promote energy generation from renewable energy sources, generators may construct low voltage lines (up to 33 kV) and connect it to the nearest pooling station of STU/CTU.

- (b) MSETCL stated that transmission planning for integration of renewable energy is also important because if we connect renewable generation at the voltage level below 220kV, losses will come down and therefore, transmission system is relieved and we may not be required to plan additional transmission system.
- (c) ERPC stated that the Govt. of India has set an ambitious target of achieving 175GW of Renewable capacity by 2022 including 100GW of Solar & 60GW of Wind. Every individual State has been provided with a set individual target. As and when such RE projects are commissioned and start operation, it may become further difficult to ascertain the GNA quantum of States due to intermittent nature of such projects.

4.3.5 Suggestions regarding Bank Guarantee:

- (a) Association of Power Producers stated that why POWERGRID is asking for BG when it is entrusted with

making transmission system ahead of generation. A generator goes ahead with setting up power plant which requires far more investment without any guarantee but POWERGRID requires BG for going ahead with implementation of transmission system. They added that members of APP are committed to pay transmission charges from the date of commencement of LTA/GNA in case of delay in commissioning of generating plant provided that POWERGRID/ transmission licensee is also made to compensate generators for delay in commissioning of transmission system. They suggested that while implementing GNA, the Committee needs to devise a mechanism to make States liable to pay for Withdrawal GNA.

- (b) Power System Experts stated that BG is required to cover up situation of transmission capacity getting stranded. They stated that out of the major part which may get stranded is dedicated line which has been proposed to be built by generator and only a part of system beyond pooling point is less utilised which ultimately improves reliability. They suggested that Exit Charges should be less and BG, if it has to be fixed, should not be more than Rs. 5 lakh/MW. They also suggested that high amount of BG from generator is a harsh measure as no generator willingly defaults or delays in project commissioning. This may discourage investment by IPPs.

- (c) NRPC stated that BG should be made appropriately higher to deter non-serious generators from seeking GNA and relinquishment charges should be priced appropriately.

4.3.6 Suggestions regarding issues related to Exit Charges:

- (a) Power System Experts suggested that although it the prerogative of the Commission to decide the quantum of Exit Charge on case to case basis. However, the Exit Charges should not be more than few month's transmission charges. It is unfair to levy generators to compensate fully for the transmission system underutilized. It should be seen if contractual agreements can be covered through some kind of power project insurance since all projects ultimately help in nation building, a part of risk (like generator quitting) should also be covered by the Government also. They also suggested that GNA is forward step and is line with the provision of the Act relating to non-discriminatory open access. Under GNA regime, a generator would exit only if the project gets abandoned due to some reason but the transmission system laid for such generator (other than Dedicated Line) would be utilised by other generators. The transmission system built will enhance reliability of system as acknowledged by the Commission while granting regulatory approval for implementation of HCPTC in Petition no. 233 of 2009.
- (b) PCKL and KPTCL have suggested that relinquishment shall lead to physical disconnection from ISTS grid. Therefore,

GNA holder may be given exit option after payment of compensation to CTU initially and obtain certification by competent authority that there is no stranded capacity consequent to such exit.

- (c) KPTCL has suggested that drawee entity is expected to take GNA corresponding to import requirement as a buyer/ export requirement as a seller. Transfer of physical GNA right should be allowed subject to set up registry to keep track of such GNA transfers on short term basis through power exchange or NLDC.
- (d) GETCO has stated that if relinquishment of GNA shall lead to physical disconnection from ISTS grid, this shall defeat the entire purpose of transmission network planning which essentially requires commitment to pay the transmission charges. The provisions pertaining to 'Exit Option' under the Open Access Regulations will become redundant. Why should the CTU develop transmission network if the generator can walk away at its sweet will without any financial commitments.
- (e) TPDDL stated that it is not clear that how the issue of stranded assets and relinquishment charges would be handled in the GNA regime. The prevailing CERC regulations mandate for payment of relinquishment charges for a period of up to 12 years if the approved LTA is surrendered by any beneficiary. In this case relinquishment charges become very huge and hence the concerned beneficiary is reluctant to give away its LTA. The same leads to underutilization of the transmission assets

at one hand and in a few cases even leads to stranded assets. The relinquishment charges should be equivalent to say transmission charges for 1 or two years. The same may give a motivation to the surrendering utility at one hand and ensure proper utilization by the other beneficiary leading to optimal utilization of the Transmission assets.

4.3.7 Suggestions regarding import/export requirement and demand forecasting by States:

- (a) STU, Maharashtra suggested that load forecasting should be done by DISCOMs as they are the load serving entity within the state. He stated that presently people are moving from long term power procurement to medium term or short term power procurement and also they are going for open access for procurement of cheaper power from outside the state and therefore, it is very difficult to determine the ISTS drawal requirement for next 5 years. He suggested that we should devise a mechanism as to how load forecasting is to be done and how to address concerns of the DISCOMs in this regard. He also suggested that commitment to pay transmission charges for said ISTS drawal should be taken from DISCOMs and not from the STU.
- (b) CEA stated that States have both own generation and load and they are required to balance their generation & load and finally come out with their drawal GNA requirement from ISTS as ISTS is planned to serve States not the DISCOMs within the State. He added that the only problem

an STU can face is that STU may not be the appropriate entity to enter into a commercial agreement with ISTS licensee on behalf of DISCOMs. He stated that States are in better position to estimate their upcoming load centres and generation in next 5 years within their territory. He suggested that worldwide load forecasting is done for planning transmission system and states should also start load forecasting to assess their drawl requirement from ISTS.

- (c) KSEB stated that demand forecast in the state of Kerala is based on statistical extrapolation added with econometric weightage factors and demand forecast done for long term (up to 20 years perspective plan), medium term (3 to 10 years) and annually (before filing ARR). He stated that the short term forecast also capture weather changes like poor monsoon or long spell of dry period when consumption increases abnormally and heavy monsoon which results in abnormally low demand. He further stated that in Kerala, generation, transmission and distribution is not unbundled and they are doing load forecasting based on our past 3-4 years data with 4-5% variations. He also stated that KSEB can estimate the GNA quantum.
- (d) GRIDCO stated that as per the national Tariff Policy and the State Grid Code, DISCOMs are mandated to do load forecasting within their jurisdiction. DISCOMs furnish the peak demand (MW) & energy demand (GWh/MU) projections for each of the succeeding 5 years for each interconnection point with STU substations and based on

said projections by DISCOMs, STU works out the electricity demand forecast for the next five years by extrapolating the energy requirement considering the growth rate of consumers & consumption pattern adopted by the DISCOMs. However, the demand forecast is only an indicative forecast, which would facilitate the identification of resources of power for advance action. These have to be reviewed from time to time when the outlines of the perspective developments on a longer time horizon become available. GRIDCO suggested that CEA may prescribe one uniform method for all DISCOMs/State Utilities for Electricity Demand/Load Forecasting so that a rational demand through ISTS can be ascertained after excluding the Generations within the State. Also, STU is working out demand/load forecast based on projections by DISCOMs, any variation to forecasted load/demand in terms of GNA should be to the account of DISCOMs due to the fact that the DISCOMs can overdraw/underdraw whereas STU is only the carrier of such overdrawal/underdrawal power. Hence, the responsibility of drawal beyond the approved GNA quantum & financial implication thereof, if any, should lie with the DISCOMs.

- (e) Gujarat suggested that it is very difficult to assess import/export requirement because of several diversities involved like availability and price of coal & gas, policy for encouraging renewable generation, etc.
- (f) NRPC stated that State utilities are not able to forecast their demand even for a few months period because of

multiplicity of agencies and lack of demarcation of responsibilities among DISCOMs, STU and SLDC. He suggested that State agencies i.e. DISCOMs, STU and SLDC should be equipped with adequate technological tools to enable them to do forecasting. There is a lack of effective transmission planning & execution in States resulting into TTC constraint, delay in downstream system, etc. As envisaged under GNA, States should prepare long-term transmission plan and implement transmission system in coordination with CEA and CTU. State should be allowed a margin in GNA estimation with penal charges for deviation. States should also be compensated appropriately in case system is unable to provide GNA.

- (g) DISCOMs of Delhi stated that they can forecast their demand but it is very difficult to forecast import/export requirement from ISTS 5 years in advance. They suggested that STU and DISCOMs should together do load forecasting and import/export requirement from ISTS 5 years in advance. Regarding non-readiness of downstream system, they stated that DISCOMs submit their data well in advance and if CTU / STU system is not ready, they should bear charges for that.
- (h) STU Rajasthan stated that they support GNA based planning, however planning should be done in a manner that there should not be any loop flow. They further stated that planning for integration of renewable is very important in the state of Rajasthan which should also consider planning for adequate reactive power.

- (i) DISCOMs of Rajasthan stated that if transmission charges increases with implementation of GNA, it will not benefit the consumers and this aspect should be taken care. Further, it is not possible to forecast import/export requirement from ISTS 5 years in advance. He also suggested that impact assessment of GNA may be done.
- (j) Power Company of Karnataka Ltd (PCKL) stated that the main grounds for the DISCOMs/drawee entities for not providing the drawl/injection requirement from the ISTS is mainly due to the fact that
- (k) None of load forecasting methods are accurate. The load forecast model that works well in one utility may not be the best model for another utility. Even within the same utility, a model that forecasts well in one year may not generate a good forecast for another year.
- (l) Many factors influence the load forecasting accuracy, such as geographic diversity, data quality, per capita income, government policy, population growth, agricultural and industrial growth and customer segmentation etc.,. As the load forecasts is the basic foundation on which transmission and distribution systems planning, Generation planning etc., is dependent upon, inaccurate load forecasts may result in financial burden to DISCOMs.
- (m) As such, it is imperative that utilities have to devote substantial time and resources to develop credible load forecasts and at times may end up in forecasts which may deviate from the forecasted one in view of so many factors attributable to it. PCKL suggested that certain amount of

leverage is to be allowed to DISCOM's on Drawal/injection under GNA without imposing any penalty for deviation on the declared quantum of GNA preferably allowing such deviation to be in the range of $\pm 10\%$ over the declared GNA.

- (n) ERPC stated that assessment of quantum for GNA requirement is very critical and concern of all the stakeholders which need to be properly addressed. To ascertain the quantum of GNA, the existing power market as well as the anticipated future power market scenario needs to be factored in MTOA & STOA (both Bilateral as well as Collective Transactions) are increasing day by day. He also suggested that in case a particular generator is not able to provide power, it should be allowed from other generators and PPAs may be modified accordingly. He further suggested that forecasting should be streamlined and there should be clear demarcation responsibilities among among DISCOMs, STU and SLDC.
- (o) TPDDL stated that import/export requirements of a utility depends of many uncontrollable factors such as season, load pattern, load growth, prices of power under long term PPAs, prices of power in Bilateral markets and other short term instruments such as power exchanges etc and last but not the least paying capacity of the utility. These all parameters cannot be predicted 4 years ahead for the next 5 years as mentioned in the short note provided by CERC. Forecasting of GNA including all the above mentioned parameters may lead to misleading GNA declaration by

states and the same may lead to additional GNA charges liability in case of over prediction of the GNA & penal charges in case of under prediction of the same. TPDDL can provide its demand forecast for a period of next five years or 10 years as required. However, providing Demand forecast for Delhi as a whole should be responsibility of STU. STU should collect the demand forecast from other DISCOMS of Delhi, combine it and then submit to the CEA/the designated Nodal agency.

4.3.8 Suggestions regarding non-completion of downstream system:

- (a) PCKL suggested that recovery of penalties for non-completion of works through Implementation/Connection Agreement including downstream work as approved in standing committee meeting are subject to execution of Implementation/Connection Agreement. Transmission line along with associated assets for evacuation of power being implemented through Tariff based Competitive Bidding or other than through Tariff based Competitive Bidding or other means of bidding then concerned generating company and transmission licensee shall enter into connection agreement. Where transmission system executed by the Transmission Licensee (CTU/STU) is required to get connected to the existing transmission system executed by other transmission licensee selected through Tariff based Competitive Bidding shall enter into connection agreement. Penalties for non-completion of

works in time by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement, for indemnification of each other against losses incurred in this regard, and form a part of this Agreement. In case there is involvement of more than two parties then tripartite agreement between CTU/STU and TSP, or CTU/generating Company and TSP as the case may be is necessary.

- (b) GETCO has suggested that in case of non-availability of downstream network, the STU shall not bear the commercial implication as there will not be any Agreement in this regards with the STU. The state DISCOMS have to face the implication and therefore their concurrence should be taken. It is observed that after the POC is implemented the CTU is insisting to declare the COD at the earliest so as to recover the POC immediately from the beneficiaries. CTU and STU should work in a coordinated manner so that the work by both CTU and STU can be completed at same time. In any case since the financial impact of recovery of the charges proposed are affecting the DISCOMS of state, it would be appropriate to take their confirmation on this issue.
- (c) TPDDL stated that in case of non-availability of downstream network leading to non-utilization of the associated ISTS, or vice-versa, the responsibility of the concerned agency (CTU or STU) should be fixed clearly for the payment of the tariff /penalties pertaining to the stranded assets.

- (d) GRIDCO stated that CTU may be liable for payment of STU assets, if downstream network of STU is commissioned, whereas CTU network is not commissioned which is required to inject power to the STU network on the similar line as STU's payment liability in case of non-commissioning of its downstream network but ISTS network is already commissioned.
- (e) STU Rajasthan stated that regarding non-readiness of downstream system, the Commission has already issued order in this regard and payment of transmission charges shall be done accordingly.

4.3.9 Other Issues:

- (a) Central Repository of Generators: GETCO has stated that the mere registration by a generator with the Central Repository cannot become the base for transmission planning as well as implementation unless and until the ground reality are assessed and the project actually takes off for implementation. There are so many instances wherein many projects have been conceived but have not still been implemented and for which transmission asset is already created. Such asset is not of no use till the power project actually is set-up and it is disastrous when the power project itself is hovering under uncertainty.
- (b) TPDDL stated issues related to need to remove information asymmetry as follows:
 - (i) Proposal of every transmission scheme seeking approval should contain the details on its effect on

the transmission capacity on the existing network along with the cost benefit analysis and incremental effect on the Tariff. Every investment proposal should be made available in the public domain and details should be provided to the intended beneficiaries.

- (ii) Standing Committees/Validation Committee as the case may be for power system planning should meet on a quarterly basis and strict monitoring should be done on the progress of transmission projects.
- (iii) A committee should be constituted for correct assessment of stranded assets and its effect on the overall transmission capacity if put under use. Sharing of cost of stranded assets due to excess planning margins or due to non-usage by the intended beneficiary need to be addressed. Further, Stranded assets should not be a part of the YTC calculation and such cost should be recovered only by the defaulting party.
- (iv) More importance is required for development of intra-State networks, where Utility /Discom face the operational constraints due to insufficient transmission capacity in the existing system.

CHAPTER-5

BACKGROUND OF TRANSMISSION PLANNING

5.1 Introduction

5.1.1 CTU has in 'Concept Paper on proposed changes in Transmission Planning, Augmentation and Sharing of Charges under GNA-Regime' (Concept paper on Proposed Changes in Transmission Planning, Augmentation and Sharing of Charges under GNA-Regime, May 2016) brought out the following drawbacks in the present system:

- (a) Commitment is sought from generators who are clueless of where the power will be sold.
- (b) Uncoordinated capacity addition by generators.
- (c) Abandonment/ surrender/relinquishment by generators.

5.1.2 CTU has outlined broad proposed transmission planning process as under:

- (a) Initiation of the transmission planning process shall be made with the demand projections of each State, which will be subsequently expanded to include the import/export requirement of each State.
- (b) Central Reposting of Generators
- (c) GNA by generators-Generation addition inputs.
- (d) Evolution of transmission system & its implementation.

5.1.3 The brief of the existing transmission planning process and changing market scenario as submitted by CTU in the concept paper is detailed in the following paragraphs.

5.2 Transmission Planning Process – historical perspective

Earlier Transmission Planning Process: Era of Load-Based Planning & ‘Certainty’

5.2.1 Prior to Open-Access regime, planning of Inter-State Transmission System was based on the demand forecasts for States/Union territories, provided in the periodic Electrical Power Survey (EPS) conducted by CEA.

5.2.2 The electricity demand for a State/UT was considered to be met by State owned generating station and balance demand by allocations made from central sector generating stations. At the planning stage, a tentative share of power allocated by MoP was taken into account which was finalized later on and transmission system was planned for evacuation and delivery of the share of power from Central Sector generating station to the identified beneficiaries. The transmission system so evolved was approved/ concurred in the Standing Committee /Regional Power Committee Meeting.

5.2.3 It was an era characterized by certainty and the implementation of transmission system was secured by SCM/RPC/approval /concurrence for payment of transmission charges.

5.3 Present Transmission Planning Process: LTA based planning

5.3.1 Currently, the transmission planning process is largely driven by the Long-Term Access (LTA) to the ISTS sought predominantly by generators and augmentation of inter State transmission system is taken up primarily for meeting the LTA requirement.

5.3.2 In the earlier transmission planning process, States were active stakeholders but due to dearth of Case-I bidding for procurement of power by States, the new generation developers were finding it difficult to find the beneficiaries, however, at the same time, the generation projects were being implemented unhindered. To tide over the situation of lack of adequate transmission system by the time the generation gets commissioned, CERC had incorporated the provisions for seeking LTA based on Target Region(s) by IPPs. Under such a situation, though the evolved inter-State transmission system based on Target Region was discussed with the State utilities, however, due to the fact that they did not have long-term PPAs with such IPPs, the participation of the States in the consultative process became rather passive. At present, the augmentation of transmission is therefore carried out based on LTA applications made on target regions and commitment from IPPs.

5.3.3 Analysis of important indicators and factors of Transmission Planning in Pre- & Post- Open Access Regime

S. No	Indicators	Pre-Open Access Regime	Under Open Access Regime	Analysis
1.	Primary Drivers for Transmission Augmentation	Load-demand forecast of State/UTs and prior signing of long-term PPAs by States from new generation projects based on the MoP allocations.	LTOA/LTA applications by IPPs/beneficiaries . No prior knowledge of the beneficiary from the projects, therefore, the LTAs are sought based on Target Region. No attempt from States to come out with their Import/Export requirement from ISTS.	Load/Demand driven augmentation had greater certainty. Since LTA is sought on target basis, it often results in creation of transmission capacities without assurance of ultimate use by the intended beneficiaries. Upon firming-up of beneficiaries in other regions, the transmission systems are susceptible to both – congestion as well as stranding.
2.	Framework for Transmission Implementation	Based on consultative concurrence / approval from State utilities who were the end users.	Based on the BPTAs/LTAAs signed by the IPPs System is developed completely on contractual/regulatory premise.	The introduction of ‘Agreements’ in the regulatory regime has led to IPPs denouncing their regulatory and statutory obligations and seeking refuge under ‘force majeure’ clauses. Defaults in maintaining payment security mechanism, ensuring generation project

S. No	Indicators	Pre-Open Access Regime	Under Open Access Regime	Analysis
				development within reasonable time frameworks etc are being contended as mere 'contractual breach'. Whereas, if such breaches were only 'contractual', then the impact of the same ought not to have been borne by third parties i.e. other DICs, transmission licensees, nodal agencies etc.
3.	Commitment for Service of Transmission Assets	Based on the consultative agreement for bearing transmission charges in the Standing Committee/ RPC	Pre-PoC (under BPTA) : LTA Applicants Post- PoC (under TSA) 1. Pre Operationalization of LTA - By Generator 2. Post Operationalization of LTA) DICs - For firm PPAs) Generator - For target LTAs.	The present scheme has shifted the focus from requirements of State Utilities identified through consultative approach to LTA commitments that are not aligned with State's requirements. The shifting of approach to 'commitment' from 'requirement' has led to serious legal and commercial issues.

5.4 Change in Market Scenario and Customer Aspirations

5.4.1 In the last decade, the Indian power sector has experienced radical changes in the ways in which generation and transmission of power were governed. Prior to enactment of Electricity Act, 2003, the Inter-State generating stations were mostly setups by with Central Public Sector Generation companies and allocation of power to be different beneficiaries used to be made by Govt. of India. However, with de-licensing of generation and a freedom to sellers and buyers of electric power to choose whom they were transacting with, buying and selling of power became a function of market principles. This basically introduced competition and thereby overall efficiency in the power sector and availability of cheaper power to the end customer as envisaged in the Electricity Act, 2003.

5.4.2 Under the competitive environment, following radical changes are being observed-

- (a) From recent trends experienced in grant/operationalisation of LTA as well as MTOA by CTU, it appears that the power procurement by State utilities has moved from long term contracts of about 25 years to shorter term contracts. In the recent past, only few States have carried out Case-I bidding for procurement of power on long term and that too for much less quantum, however, on the other hand the procurement is mainly done for medium or short term basis. Further, the growing transactions at power exchange indicate that a shift in preference from long term PPAs

towards short or medium term PPAs. Therefore, there is a need that transmission planning which is presently linked to long term access should be realigned to anticipated power transactions in the shorter format of power purchases.

- (b) The State Utilities are even backing down their own generation, if cheaper power is available anywhere in the Grid. Further, there are number of instances where State utilities are surrendering their shares from CSGS allocations, whereas in the past, such allocations used to be a lifeline for State's power requirements. With the capacity adequacy addressed to a great extent, it becomes necessary that the cost of power needs to be inculcated to capture the merit order dispatches in the transmission planning under the competitive market environment.
- (c) The privatized DISCOMs are aiming at least-cost procurement of power for which they seek to harness the electricity market in a more effective way.
- (d) The State Utilities are lacking the wherewithal for long-term projection of procurement in the market scenario. In the reformed SEBs structure, STUs are responsible for ensuring development of Intra-State transmission system and coordinate with CTU for ensuring development of Inter-State Transmission system to facilitate the import-export requirement of the State.
- (e) Customer aspirations are accordingly changing in line with the above changes in the electricity sector. Therefore, there is a need that transmission planning is also aligned to

meet the customer aspirations rather than sticking to the outdated model of planning transmission system only associated with the long term PPAs. The need of the hour in fact is to facilitate the transfer of power that are going to take place on economic principles.

CHAPTER-6

ANALYSIS AND CONCLUSIONS

6.1. Introduction

6.1.1.The Committee noted the issues raised by transmission planning agencies namely CEA and CTU, system operator, Ministry of Power, Stakeholders including generating companies, transmission licensees, STUs, DISCOMS as well as power system experts.

6.1.2.The Committee reiterates the broad heads under which various issues have been summarised for deliberation, as under:

- (a) Conceptual basis of transmission planning (LTA with Deep/Shallow Connection or GNA), stakeholders' participation in the planning process, handling mismatch between commissioning of generator and transmission system and reservation of capacity for STOA / Power Exchanges
- (b) Need for granting Connectivity separately, the charges for Connectivity, inordinate time taken by the generators in applying for LTA after grant of Connectivity, application for LTA being much less than Installed Capacity, Charges for Relinquishment of LTA etc.
- (c) Application Fee and Bank Guarantee towards construction of transmission system
- (d) Utilisation of Congestion Charges
- (e) Other emerging issues

6.1.3. The above issues and suggestions/recommendations of the Committee are discussed in the following paragraphs.

6.2. Transmission Planning :

6.2.1. The Committee noted that many of the stakeholders and experts have pointed out difficulty in planning of transmission system based on LTA as many of the DISCOMs are not inviting Case-1 bids which in turn leads to lack of long-term PPAs and lack of LTA applications. The generators have, therefore, been seeking LTA with target region but in due course of time find need for change in target region depending on Case-1 bids in which they succeed. In such a situation, generators are required to pay relinquishment charges in the target region for which they had sought LTA initially and be in the queue for seeking LTA or MTOA in the region in which they have entered into PPA.

6.2.2. The Committee also took note that NEP and Tariff Policy specify that CTU/STU should undertake network expansion after identifying the requirements in consonance with the National Electricity Plan and in consultation with stakeholders, and taking up the execution after due regulatory approvals and prior agreement with beneficiaries would not be a pre-condition for network expansion.

6.2.3. There has been huge generation capacity addition in the country in last five years resulting in availability of

substantial spare untied generation capacity in the system. Some of these stations are capable of providing power at cheap rates. Availability of National Grid facilitates transfer of power from available cheaper sources. This has opened up opportunities for economic despatch of generating stations. Many states are backing down their own generating stations or not scheduling power from costlier ISGS and buying power from other sources through medium /short term open access. This type of situation was not envisaged earlier and has not been incorporated in transmission planning process. The present transmission planning philosophy doesn't fully take care of economic dispatch which is taking place in real time.

6.2.4. In view of these provisions and the difficulties arising due to present planning process, the Committee is of the view that there is a need for change in the basis for transmission planning.

6.2.5. Alternative-1 brought out in the staff paper is similar to currently prevailing dispensation which may pose difficulties such as generators seeking only connectivity, part LTA, lack of involvement of 'Withdrawal DICs' in regard to their drawal requirement from ISTS as listed in Chapter-2. Suppose a generator initially only seeks Connectivity Access (Option-B of Alternative-1). It will seek LTA or MTOA subsequently only when DISCOM(s) call for bids or in the absence of Case-1 bids, it may seek LTA with target region(s). Thus, the development of ISTS

would continue to face the difficulties which are being faced currently. In case, a generator applies for LTA only after it qualifies in Case-1 bids called by a DISCOM for long-term supply, LTA can get operationalized only if the margins are available in the existing transmission system or after augmentation of transmission system for evacuating the power of generator to the LTA beneficiary(ies). Thus, development of transmission system would still remain dependent on PPAs, which is not the intent of NEP and Tariff Policy. Further, Alternative-1 does not seek any involvement of Withdrawal DICs for whom transmission system is being developed. This will pose problem in development of transmission system which should be adequate for delivery of power from desired sources to the DISCOMs.

6.2.6. Most of the stakeholders have suggested that Shallow Connection may be allowed for renewable projects and a few have opined that Shallow Connection may be resorted to for renewable as well as conventional projects. Planning of transmission system in the context of large scale development of renewable energy sources contemplated by Government of India have been suggested by stakeholders and listed in Chapter-4.

6.2.7. GNA based development of transmission system, on the other hand, is not linked to PPAs. Development of transmission system under GNA would be based on (a) anticipated generation and demand scenario (b) Withdrawal GNA representing the quantum of power each

STU/Bulk Consumer anticipates to draw from the ISTS (c) Injection GNA and (d) the long term PPAs already in place. This would address the problems being faced presently on account of generators not seeking LTA or seeking LTA for a quantum much less than Installed Capacity and would also get requisite participation of and contribution from the Withdrawal DICs, who are in best position to project their drawal requirements, as part of the transmission planning process.

6.2.8. While some of the STUs/DISCOMs have supported GNA based transmission planning, some of them have made an observation that concept of GNA is not fully understood by them and it may need discussion. A short note in regard to the concept of GNA was circulated on 11.5.2016 before inviting STUs/DISCOMs with a request to furnish their comments in the meeting to be held on 17.5.2016. The concerns raised by STUs/DISCOMs have been taken care of while formulating the proposed GNA in this report.

6.2.9. The Committee finds that the main concern of DISCOMs/STUs is difficulty in proper assessment of 'Withdrawal GNA' in view of uncertainties in regard to demand forecasting and procurement of power from sources outside the State depending on relative cost economics of their generation and levy of penal charges for drawal beyond GNA. Few States have expressed that it may not be possible for them to forecast their import/export requirement from ISTS four years in advance since it will change due to change in policies of

Government for attracting investment in the State and addition of renewable capacity and change in quantum of power drawn by open access customers. They have raised a concern that their withdrawal requirement changes seasonally.

6.2.10. The Committee agrees to the point underlined by CEA that the State entities are in best position to project their drawal from ISTS keeping in view various State specific factors in regard to demand, internal generation, open access, etc. Further, STU is obligated under Section 39(2) (b) of the Electricity Act 2003 to discharge all functions of planning and co-ordination relating to intra-state transmission system and under Section 39(2) (c) of the Electricity Act 2003 to ensure development of an efficient, co-ordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centres. Committee is of the opinion that as part of the process to fulfil this mandate, the STU needs to assess the anticipated withdrawal from ISTS in different seasons. The Committee has, therefore, proposed that the STUs may assess demand incident on ISTS in coordination with DISCOMs, generators located in the State, CTU, etc., as obligated under Section 39(2) (b) of the Act. Further, Withdrawal/Injection GNA so assessed by the STUs would be discussed in a Validation Committee under the aegis of CEA, wherein collective wisdom and knowledge of concerned players based on the load flow studies for different scenarios carried out by

CTU based on economic principles of merit order operation would enable a fair assessment of demand incident on ISTS in different seasons. The Committee suggests that States should be allowed to seek seasonal GNA. The Committee also recommends that STU may revise its GNA quantum for the sixth year. Regarding the contention of STUs/ DISCOMs regarding uncertainty of GNA due to open access customers, it is to be noted that even if a customer avails power under open access from outside the state, overall GNA of STU would remain same considering that in such case drawal from ISTS by DISCOMS of the State for supply to consumers other than open access consumers would be less and to that extent the drawal of open access consumers will increase. STU may develop a mechanism for charging deviation transmission charges from its consumers as per Regulations framed by SERC. Further, the DISCOMs/ Bulk Consumers would be required to pay transmission charges on the basis of drawal from ISTS as captured in the Base Case for determination of PoC charges. Keeping in view the uncertainties and difficulties in regard to assessment of demand as expressed by STUs/DISCOMs, Committee recommends that additional transmission charges be levied only if drawal of STU/DISCOMs in a State from the ISTS is beyond 120% of the Withdrawal GNA projected for the corresponding period in respect of the STU. The Committee is of the view that the additional transmission charges for the drawal above 120% of GNA

may be kept equal to 125% of the normal transmission charges.

6.2.11. The Committee finds that GNA based transmission planning has by and large been found to be acceptable to CEA, CTU as well as POSOCO. The Committee also finds a fair degree of in-principle acceptance of GNA by DISCOMs and STUs but for certain clarifications. The Committee suggests that the proposed methodology detailing the Connectivity, Access, time lines for application/grant of Connectivity and Access, sharing of transmission charges on the basis of usage, treatment of mismatch between commissioning of generating station and transmission system, etc., as detailed herein would set at rest most of their concerns.

6.2.12. The Committee notes that despite 'Injection GNA' being equal to maximum injectable capacity of a Generating Station, evacuation of full power of the Station or delivery of power to the STUs/DISCOMs/Bulk Consumers equal to the total power contracted by them from sources outside the State cannot be guaranteed in all situations. But such situations are found even at present due to congestion in ISTS or intra-state transmission system. The Committee is of the view that with GNA based transmission planning, probability of inadequacy of ISTS is expected to reduce substantially in next 4 to 5 years after the transmission system commensurate with GNA based planning is in place. Needless to mention that proper assessment of

Withdrawal GNA would go a long way in setting up ISTS of requisite capacity.

6.3. Proposed Transmission Planning Process.

6.3.1. Principles of Transmission Planning

While making the recommendations, the Committee has considered the principles of transmission planning philosophy by FERC in its Order No. 890 and 1000 (www.ferc.gov) which recognizes the importance of openness and transparency in transmission planning. The following principles of the FERC Order form the basis of our consideration:

- (a) Transmission planning meetings must be open to all affected parties including, but not limited to, all transmission and interconnection customers, State Commissioners, and other stakeholders.
- (b) Transmission providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans.
- (c) Transmission providers are required to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans.
- (d) In so doing, stakeholders or an independent third party can replicate the results of transmission planning studies to confirm that transmission planning was not conducted in an unduly discriminatory fashion.

The Committee recommends that above principles should form the basis while carrying out planning of transmission system in the Country.

6.3.2. Central Repository of Generators:

- (a) At present, there is no central repository of generators which are in planning and construction stage and this causes an information-lag for the planners of transmission system. A number of IPPs have been commissioned in the 11th and 12th Plan which were not in the plan proposal of MoP/CEA and were not considered in the system studies undertaken by CEA and CTU for transmission Planning. After de-licensing of generation, the need for a central repository is more vital than ever. Such a repository should contain information in regard to the likely generation additions in the country including Renewable Energy projects interconnected to ISTS as well as Intra-State Transmission System, starting from inception of the Generating Station till its commercial operation with periodic update of their status.
- (b) Periodicity of update regarding specified milestones and other details should be specified in the Detailed Procedure to be prepared by CEA. The Committee recommends that the frequency of updating of status may be monthly for the units to be commissioned during the ensuing year and quarterly for other units. In addition, a generator should also indicate status of signing of PPA in its periodic update to Central Repository. This would also be in line with the duty entrusted upon Generators under Section 10(3) of the

Act. Section 10(3) (a) of the Act provides for submitting technical details to Appropriate Commission and Authority and Section 10(3) (b) provides for coordination with CTU or STU as the case may be for transmission of the electricity generated by it.

- (c) Accordingly, it is suggested that a Central Repository of Generators be created in CEA where any generation project developer proposing to set up a new generation plant must register itself. CEA may seek requisite information from the generation project developer under Section 74 of the Act. This will not only provide vital data for the transmission planning process but would alleviate problems due to uncoordinated generation additions. CEA may indicate the format in which the information has to be furnished by the Generators at the Central Repository.

6.3.3. General Network Access by Generators–Generation Addition Inputs-Injection GNA:

The new generation projects that are intending to avail the transmission services from ISTS should be required to avail General Network Access (Injection GNA) from CTU. The information made available through applications for GNA should facilitate receiving generation input data for the transmission planners to evolve optimal transmission plans. Salient features of such GNA are given below:

- (a) GNA should be akin to the present concept of Connectivity plus LTA with the difference that its quantum should mandatorily be required to be equal to the installed

capacity minus auxiliary consumption. An Applicant may seek phased GNA in accordance with the commissioning schedule of its units.

- (b) In case of captive power plants (CPP) with co-located captive load, the CPP should have option to take Injection GNA corresponding to installed capacity less normative auxiliary power consumption less the captive load estimated by the CPP for the co-located captive plant. For captive power plant not located at the same place as captive load, the captive power plant should take Injection GNA corresponding to the captive load to be met and any additional quantum of power that the CPP wants to sell to other persons. CPPs connected to the CTU should also have the option for applying for Withdrawal GNA for meeting captive requirement under contingency of tripping of its captive power plant and for meeting start-up power requirement of CPP. In case of Generators supplying free power to home State, GNA may be sought for capacity less free power only if the State makes its own arrangement for drawal of free power from the bus-bar of the generating station. Phased/unit-wise GNA based on estimated CoD of the units should be permissible to the generating projects.
- (c) GNA should be required to be obtained four (4) years prior to the expected date of commissioning of the generation project. Some relaxation (2 year in place of 4 years) can be given for solar and wind generation projects considering their low gestation period. In case GNA is sought for less

than 4 years in advance, the same may be considered for grant by CTU if it can be accommodated on existing system or the system which is already under execution and is likely to be commissioned in the time frame of commissioning of the generator. In case of early commissioning of generator, CTU may operationalize its GNA (partly/fully) prior to date from which GNA has been granted if it can be accommodated on the existing system.

- (d) GNA should attract Reliability Charges as specified by the Commission. The Reliability Charges should be applicable from the date of first synchronisation of a unit corresponding to its installed capacity minus normative auxiliary power consumption.
- (e) Relinquishment of GNA should lead to disconnection from grid. In case an IPP has been converted to CPP and it relinquishes its GNA, it should be liable to pay Relinquishment Charges as specified by the Commission. In such a specific case the Connectivity for such plant may continue subject to payment of Reliability Charges corresponding to the capacity of the larger size unit less normative auxiliary consumption.
- (f) Generating station seeking GNA to the ISTS should be responsible for construction of the dedicated transmission line(s) from its switchyard to the ISTS point(s) identified by CTU while granting Connectivity/GNA.
- (g) GNA and its associated connectivity may be applied by a trader on behalf of a generator provided that the trader fulfils the entire requirement as expected of a generator.

6.3.4. Planning of Transmission System & its Implementation

- (a) The inputs regarding the generating stations which are likely to come up would become available to the transmission planners from the Central Repository of generation projects, applications for GNA and STUs.
- (b) The demand projections by the STUs estimated by them in coordination with the DISCOMs should form the baseline for transmission planning.
- (c) The projected/anticipated quarterly maximum import/export requirement in respect of a State (which should be called its Demand/Injection GNA respectively) from ISTS will be provided by the State Transmission Utility (STU) 4 years before for a period of 5 years to CTU. Such data should be provided by concerned STU after taking into account the anticipated demand figures from each DISCOM in the State and likely generation from the generating companies having generating stations in the State. For example, in January 2017, STU should provide its peak quarterly requirement from ISTS (Injection/Withdrawal GNA) for years 2021, 2022, 2023, 2024 and 2025. Such data should be provided on Annual rolling basis i.e. in January 2018, STU should provide its GNA for 2022-2026. STU can revise its projected GNA for the year 2022 in the year 2018 but would not be allowed to revise the same for the year 2021 keeping in view construction timeline for transmission system being of the

order of 3 years plus 1 year processing time. For the first year of implementation of GNA, STU should provide Injection/Withdrawal data for immediate 4 years also. In the present example for years 2017, 2018, 2019 and 2020. This will aid in estimating projected GNA for subsequent years.

- (d) In case the projected import/export requirement is not provided by STU, CTU should, in consultation with CEA and POSOCO, assess the import /export requirement of the State for the purpose of transmission planning and upload the same on CTU's website for comments from stakeholders. In the absence of any response to the same from STU, the projected import/export requirement assessed by CTU should be taken for transmission planning.
- (e) Bulk Consumers directly connected to ISTS need to provide their drawal requirements from the ISTS.
- (f) A Validation Committee comprising representatives of CTU and STUs should be set up under chairmanship of CEA which should validate the projected import/export requirement from ISTS provided by STUs / assessed by CTU considering the comments received from stakeholders on the uploaded data. The Validation Committee should finally approve the projected import/export requirement for each State which should be uploaded on website of CEA and CTU and should form the baseline for planning.

- (g) The import/export requirement assessment should be an Annual rolling exercise to be completed by 31st March of each year.
- (h) Transmission planning may be carried out under the aegis of Standing Committee on Transmission planning with a suitable margin above Withdrawal GNA sought / assessed for each State.
- (i) System studies should be carried out for various generation and load scenarios during peak, off-peak and other than peak/off-peak hours for different seasons considering low, moderate and high renewable capacity addition, scheduling of various generating stations which do not have any PPAs based on the relative merit order and GNA applied by the Generating Companies and the load projections of the States. The objective should be to minimize the variable cost of generation. However, balance should be struck between minimizing the variable cost of energy and the requirement of transmission system.
- (j) The variable cost of existing generating stations as available with CEA/Regulatory Commissions be considered. CERC would be appropriate authority to notify escalation indices for pit head and non-pit head plants to be considered for estimating the variable cost for planning period. The variable cost of new generating stations should be estimated by CTU in consultation with CEA and the generating stations based on likely source of fuel, normative heat rate as per CERC Regulations, variable charges of existing generating stations in a state

based on pit head/load centre based stations. In case of non-availability of data from CEA, variable charges may be considered by CTU based on similar sized units and norms for heat rate/ specific oil consumption, etc., as per CERC Regulations.

- (k) Probabilistic scenarios be developed by CTU considering varying import/export requirement of each state, which would depend on generation dispatches and probabilities of load forecasts.
- (l) These scenarios be declared upfront and options in various scenarios should be put up on website of CTU for comments/suggestions of stakeholders.
- (m) In case Injection GNA happens to be more than Withdrawal GNA, planning of ISTS should be done for various scenarios of dispatch limited to Withdrawal GNA duly factoring known firm tie-ups of power.
- (n) ISTS will be planned based on import / export requirement for approval/concurrence of Standing Committee on Transmission Planning.
- (o) While planning the transmission system, options of upgrading the existing ISTS in place of building new transmission lines such as increasing line loading through use of compensation, reconductoring, etc.for optimally utilising the existing assets, should also be considered.
- (p) If no consensus could be reached for undertaking of transmission project in SCM and the CTU considers the

need for its implementation, CTU may approach CERC for regulatory approval.

- (q) Regulatory approval of transmission System: CTU would be required to approach the Commission for approval of new transmission assets in respect of ISTS within a month of its approval by Standing Committee. Commission may dispose of such petition within 3 months of its filing after considering the objections/ suggestions from the stakeholders. Commission may develop in-house team to examine the proposal submitted by CTU independently and the objections / suggestions of the stakeholders or may hire experts/consultants with experience in power system planning for this purpose.
- (r) Based on the above, the ISTS should be undertaken for implementation either through TBCB or Cost-Plus route as decided by the Empowered Committee.. The exercise of assessing import/export requirement of each STU should be made on Annual Rolling basis and should be considered to be revised considering the most recent assessment.
- (s) Based on progress of implementation of generating stations, mid-course correction for transmission system to the extent possible should be made in terms of
 - (i) Re-configuration of planned transmission system
 - (ii) Phasing of transmission elements
 - (iii) Delay/Deferment of some of the transmission elements

- (t) Transmission Planning for Renewable Energy Sources:
- (i) Few states have suggested that renewables be connected at lower voltage levels so that losses in overall system are reduced. They have also suggested that at present Renewable Energy (RE) is not considered in totality in transmission planning as during peak load period most of RE sources would be generating less. In future RE would make power flow unpredictable and maximum RE would prevail for only few hours (typically 3 to 4 hours in a day) and would have temporal variation. Transmission planning for RES should consider emergency rating for transmission lines.
 - (ii) The Committee is of the view that transmission system may be planned by CTU/CEA based on estimated capacity additions in perspective plan and RPO of each State and approach CERC for regulatory approval for the same. In addition, the Standing Committee on Transmission Planning may consider margins to cater to renewable capacity additions. Sensitivity analysis may be carried out for low, moderate and high renewable capacity addition.

6.3.5. Availing Network Services for Transfer of Power under various Terms of PPA

- (a) GNA should, by itself, not entitle any generating station to interchange any power with the grid till it either signs a PPA/contract and registers the same with CTU or sells power through exchange. The Committee proposes that an

online portal for registration of PPA by a Generator / DISCOMS / Trader be developed by CTU.

- (b) All the registrations done in a month be considered by CTU within twenty days of end of the month and confirm the scheduling priority for the Generator / Discom / bulk consumer by the end of next month. While confirming the scheduling priority under long term /medium term/short term, CTU should give priority to long term PPAs over medium term PPAs and to medium term over short term and among PPAs of same category under prorata basis. A Generator/Discom/bulk consumer may also transact power through power exchange which should be scheduled as per available corridor.
- (b) The PPAs of more than seven years tenure be considered as Long Term PPA, PPAs from one year to five years as Medium Term PPA and PPAs of less than one year as Short Term PPA. The registration for Long Term and Medium Term PPA has to be done with CTU and for short term PPA with RLDC. Access to the ISTS should be commensurate with the term of PPA signed between the seller and the buyer of power except when the transaction is done through power exchange. However drawl of start-up power/injection of in-firm power should be allowed only after commissioning of dedicated line by the generator. It is expected that the proposed system for transmission planning will facilitate development of robust transmission system enabling economic exchange of power.
- (c) In case operationalization of scheduling for full quantum of PPA is not possible, CTU should operationalise PPA for the

maximum quantum which can be accommodated in the existing system and may indicate the date from which full quantum as sought through PPA could be scheduled. Generator and DISCOMs/ buyers may cover the eventuality of constraints in transmission system as an event beyond the control of the buyer / seller to ensure that the generator is not penalized for non-availability of transmission system.

- (d) The above arrangement should continue for next five years post which the transmission scheduling process should be reviewed considering equal priority for long/ medium /short term.

6.4. Scheduling mechanism for States

A state procures power under Long term /medium term / short term. Post operationalisation of GNA, it is envisaged that state may be able to schedule its power under any tenure (long-/medium-/short-term) as required. However, under certain circumstances it may not be possible to accommodate the quantum requested on day ahead basis on account of constraints in ISTS. Under such circumstances, the state should be asked to provide its revised schedule. Under such conditions the State's entitlement through the constrained transmission corridor may be intimated and the State may be given liberty to curtail the schedule from long term / medium term / short term transactions through the constrained corridor as per the relative economics of the transactions to the State. The total corridor capacity available to STU should

be specified. Out of available corridor, an STU should have liberty to decide which transaction it wishes to schedule. For example, if an STU has Withdrawal GNA for 2,000 MW and it has contracts under Long/medium/short term with suppliers for 3,000 MW, however on day ahead basis available corridor is only for 1,800 MW, the STU may inform POSOCO from which suppliers it wishes to avail power out of 3,000 MW so that total allocation of corridor is limited to 1,800 MW. It may so happen that multiple STUs wish to avail the corridor in which there is a constraint. Suppose corridor from WR-NR can accommodate 5,000 MW. Total GNA granted to NR beneficiaries is 6,000 MW. In such case, POSOCO should consider pro-rata capacity for each state in proportion to its long term PPAs tied up on that corridor.

6.5. GNA Agreement

An agreement should be signed by GNA applicant with CTU within one month of grant of GNA (as per the format prescribed by the CTU and approved by the Commission) and intimation by CTU to the applicant to sign the agreement. In case it fails to sign the agreement within specified time period, the bank guarantee furnished by the applicant should be forfeited. This has been proposed to have seriousness while applying for GNA.

6.6. Curtailment of transactions after finalization of day ahead schedule

When for the reason of transmission constraints, it becomes necessary to curtail power flow on a transmission corridor after finalization of day ahead schedule and in real time, the transactions already scheduled may be curtailed by the Regional Load Despatch Centre. The transactions should be curtailed on the basis of duration of transaction with short term transactions to be curtailed first, followed by curtailment of medium term transactions and thereafter curtailment of long term customers. Amongst the customers of same category, curtailment should be carried out on pro rata basis.

The aforesaid methodology for curtailment in real time operation may be reviewed five years after implementation of GNA system based on the experience during the intervening years.

6.7. Mismatch between injection GNA and drawal GNA

6.7.1. As per GNA scheme proposed by CEA/CERC staff paper, Withdrawal GNA and Injection GNA are force-matched for transmission planning. This may lead to a situation in which gap between Withdrawal GNA and Injection GNA gets distributed on drawal points on proportionate basis, thus leading to 'fixing' of drawal points. In the process, while ISTS of higher capacity will get planned at drawal

ends, system planning for transmission corridors may still remain deficient. The Committee is of the view that Withdrawal GNA should not be force matched with Injection GNA. As the bulk power market is in overall surplus condition and growth scenario indicates that this situation is likely to continue for quite some time, Withdrawal GNA by utilities is likely to be substantially less than Injection GNA.

6.7.2. The STUs are required to firm up the Withdrawal GNA in consultation with and based on inputs from DISCOMs and generating stations in the State regarding anticipated demand and their anticipated offtake from the generating stations located in the State in different seasons/month. Their Withdrawal GNA from the ISTS is likely to be maximum during the season/month when the shortfall between their demand and generation availability to them from the internal sources is going to be maximum. The Committee is of the view that this is not a difficult exercise. Requisite format for estimation of withdrawal GNA may be specified in detailed procedure to be formulated by CTU. If required, the STUs/DISCOMs could seek assistance of CEA or RPC for estimation of Withdrawal GNA. The Withdrawal GNA so assessed would then be discussed in the meeting of Validation Committee. Further, the apprehension of the STUs in regard to repercussions of error in assessment of Withdrawal GNA get addressed by the fact that the sharing of transmission

charges of ISTS is to be based on usage of ISTS. Drawal from ISTS upto Withdrawl GNA plus a margin of 20% would not attract any additional transmission charges. The additional transmission charges for drawal from ISTS beyond the margin as mentioned earlier may be kept as 25% above normal transmission charges. Transmission Planners may consider up to 20% margin above withdrawal GNA while planning.

6.8. Date of Operationalisation of General Network Access

- 6.8.1. Stakeholders have suggested that date of GNA should be firm and no relaxation should be provided. However, in force majeure conditions and if generator informs about its delay sufficiently in advance, a relief may be considered.
- 6.8.2. The Committee suggests that subject to force majeure conditions or Change in Law as specified in Paragraph 6.8.6 of this Report, the operationalisation of GNA should start from the date indicated in the letter of grant of GNA or from the availability of the identified transmission system, whichever is later and the liability of payment of transmission charges should begin from this date.
- 6.8.3. The Committee also suggests that inability of a GNA Applicant to generate/supply electricity would not absolve it from liability to pay transmission charges.
- 6.8.4. In case a generator has not started injection of power on date of operationalisation of GNA and its Point of Connection (PoC) rate under CERC (Sharing of inter-state

transmission charges and losses) Regulations, 2010 is not available, such generator should be liable to pay at all India average PoC rate for the region as its GNA charges.

- 6.8.5. In cases where operationalisation of GNA is contingent upon commissioning of several transmission lines or systems and only some of the transmission lines or elements have been declared to be under commercial operation, GNA to the extent which can be operationalised without affecting the security and reliability of the Indian Grid should be operationalised and the GNA customer should pay transmission charges for the quantum of GNA operationalised. The transmission licensee because of delay of whose transmission system GNA for an applicant could not be operationalised in full, should pay corresponding transmission charges as per its TSA, which should be provided to generator as compensation in case generator is ready and transmission system is not ready.
- 6.8.6. A generator which has sought GNA may get delayed due to reasons beyond its control or for reasons within its control for example delays due to contractor. In case a transmission system or a generator is delayed beyond the scheduled date of GNA due to event caused by force majeure and Change in Law, the date of operationalisation of GNA may be extended to the extent the delay is attributable to force majeure or Change in Law which is beyond the control of the party. Force Majeure Conditions and Change in Law may be specified in the Regulations to be framed by the Commission.

6.8.7 In case a generator gets delayed due to reasons beyond its control other than force majeure, the relief is suggested as under:

- (a) In case of delay up to three months from date of operationalisation of GNA,- a generator be liable to pay 25% of the transmission charges due on him.
- (b) In the event of delay beyond three months up to six months from date of operationalisation of GNA,- a generator be liable to pay 50% of the transmission charges due on him.
- (c) In case of delay beyond six months from date of operationalisation of GNA, generator be liable to pay 100% of the transmission charges due on him.

6.8.8. CTU should determine whether the delay was due to reasons beyond the control of the generator. In case of any dispute, the matter will be adjudicated by the Commission.

6.9 Intimation regarding termination of Power Purchase Agreement

Where the entire or part of the Power Purchase Agreement (PPA) of the GNA customer is terminated in accordance with the provisions of their agreement or through determination by a court or Tribunal or Appropriate Commission of competent jurisdiction or in the event of mutual termination, it should be incumbent on the GNA customer to give intimation about such termination of PPA to CTU and POSOCO immediately and not later than

one month from the date of such termination. CTU should consider the transmission capacity so made available for scheduling of transactions for other Long term access / medium term open access customers.

6.10. Sharing of Transmission Charges under GNA

- (a) The outline of the proposal for Connectivity, GNA, sharing of transmission charges, etc. is presented below for sake of clarity and completeness.
- (b) The transmission charges should be shared among users of ISTS in accordance with CERC (Sharing of Inter-state transmission charges and losses) Regulations, 2010.
- (c) The methodology of sharing of transmission charges should be as under:
 - (i) Prior to beginning of a quarter for which POC charges are to be specified, Designated ISTS Customers (DICs) need to provide their peak demand/injection from their generating stations. This data is fed into POC software which has the entire grid modelled. Injection into / drawal from ISTS in respect of each DIC is automatically derived from the peak demand/injection data provided by DICs.
 - (ii) Based on projected peak injection/drawal requirement, transmission charges are allocated to various nodes under POC mechanism. These charges should be divided by GNA (MW) of each DIC to determine POC rate for each DIC. These rates should be put into slabs

as per prevailing Sharing Regulations notified by CERC.

(iii) There may be cases where projected peak injection /drawal in actual time frame i.e. just prior to beginning of a quarter will be different from the GNA quantum projected 5 years before by a DIC. In such cases projected ISTS drawal/injection as projected before beginning of quarter should be used in the POC software for the purpose of allocation of transmission charges as in the prevailing CERC Sharing Regulations. However, additional charges should be levied for injection /drawal beyond GNA sought by an entity so as to bring seriousness while seeking GNA. An example is provided for clarity

(iv) An example is illustrated below for clarity:

Suppose an entity has sought GNA for 5,000 MW for Quarter 2 of year 2021-22. In May 2021, entity would be required to provide its projected demand/ injection for determination of transmission charges for quarter July-September 2021. Suppose this entity has 3000 MW under Long term PPA and 1000 MW under Medium term PPA. In July 2021 it does Short term PPA for another 2,500 MW, thereby its total transaction shall be equal to 6500 MW which is 500 MW more than 120% of its GNA, it should be liable to pay transmission charges @ 1.25 times POC rate for this 500 MW and normal POC rate for drawl upto 6000 MW.

- (v) In cases where power is tied up under contracts other than short term contracts, the POC charges should continue to be calculated directly at drawal nodes as in the prevailing Sharing Regulations.
- (d) The DISCOMs seem to have an apprehension that they may be required to pay transmission charges for the entire quantum of GNA which would be projected 4 years before and may cause huge penalty in case of wrong projection. The apprehension is misplaced as the basic premise of Sharing Regulations is that the transmission charges are usage based. Hence a DIC will be allocated transmission charges which are commensurate to its usage of ISTS as per its projected demand for the next quarter. However DISCOMs should endeavour to seek GNA as prudently as possible and there should be additional transmission charges if actual drawal is more than 120% of its GNA. GNA quantum should be used to determine the slab rate for POC Charges and additional transmission charges should be payable by a DIC only in case the drawal from ISTS is beyond 120% of Withdrawal GNA.
- (e) An entity transacting power in a grid is either an injecting DIC or a withdrawal DIC. As per the proposed mechanism for sharing of transmission charges, each entity should be paying as per its GNA quantum under first bill as per sharing mechanism currently in vogue for long term

access. Since it should be seeking GNA quantum for its maximum injectable/maximum drawal quantum required, it should transact under power exchange within this quantum for which it should pay charges under first bill. Hence there should be no separate transmission charges for exchange transactions / short term transactions.

6.11 Transition phase between prevailing LTA Regulations and new proposed GNA mechanism

6.11.1 Under the prevailing Connectivity, LTA and MTOA Regulations, Connectivity is not to be mandatorily followed by Long term Access (LTA) Application. The same has to be replaced with Connectivity plus GNA Application. Suppose the new GNA Regulations become effective from 1st January, 2017, any new application for Connectivity/GNA to be received post 1.1.2017 should be processed as per the new regulations. The treatment of Connectivity / LTA Applications received till December 2016, should be as given below:

- (a) For existing generating stations with full capacity tied up, for example NTPC/NHPC stations etc., their GNA for installed capacity minus auxiliary power consumption should be deemed to have been granted and a list of same should be published by CTU.
- (b) For generating stations where LTA has been sought for part capacity and the same is already operational, the generating station should be required to apply for additional quantum (balance quantum for which there is

no LTA) under GNA within 3 months from the date on which the new GNA Regulations/ amended Connectivity Regulations become effective, so that they have access for full injectable capacity. CTU may grant GNA to such generating stations from the date of availability of transmission system. In case no application is received from such a generating station within the stipulated time, generating station should not be allowed to schedule any power.

- (c) In case of generating stations who have applied for LTA for full capacity but their LTA is yet to be operational, CTU should consider same as GNA application for the full injectable capacity and operationalise GNA as per availability of transmission system. This would imply that there is no concept of target region once the new regulations come into force. In case LTA for only part capacity has been applied, generating station should be required to apply for additional quantum (balance quantum for which there is no LTA) under GNA within 3 months from the date on which the new GNA Regulations/ amended Connectivity Regulations become effective, so that they have access for full injectable capacity.
- (d) The applications for Connectivity / LTA received till December 2016 which are pending with CTU for grant of LTA should be processed as per the new Regulations, i.e. any applicant of only Connectivity should be granted Connectivity subject to submission of application for GNA

within 2.5 years. Any application for part LTA should be supplemented with GNA application for balance quantum within 3 months as indicated above. CTU to grant GNA for full quantum for such cases.

6.11.2 Sharing of Transmission Charges in transition phase

Sharing of transmission charges will continue to be done as is done under the prevailing Sharing Regulations provided that LTA/MTOA quantum currently considered should be replaced by GNA quantum once GNA is granted by CTU on the basis of GNA sought by the generators/ Withdrawal DICs . The process may take up to 6 months. Till then POC rates will be calculated based on LTA/MTOA. It has been proposed that there should be no separate transmission charges for short term / power exchange transactions. This mechanism can become effective only after GNA system is fully operationalized.

6.12 Suggestions in regard to the issues raised in the staff paper

Apart from procedure related to transmission planning, issues related to Connectivity, Construction stage bank guarantee, development of power market have been raised in the Staff paper which are discussed in following paragraphs:

6.12.1 Connectivity

- (a) In the staff paper certain issues related to Connectivity were raised - whether Connectivity should be retained as a separate product or Connectivity and LTA applications should be sought simultaneously, the quantum for which Connectivity should be applied, pre-requisites, if any, for grant of connectivity, charges for connectivity etc. Most of the Stakeholders have suggested that Connectivity should remain as a separate product in view of its requirement for securing finances. According to stakeholders, it enables the generators to (i) know in advance, the connection point up to which they have to build dedicated lines, (ii) finalise switchyard of the generator including generator transformer, (iii) synchronise generating unit without getting a customer, draw start-up power, and carry out performance tests.
- (b) The Committee is of the view that Connectivity needs to continue to be a distinct product in view of the foregoing. Connectivity should be applied for a quantum equal to installed capacity of generating station less auxiliary consumption. In case of captive power plants connectivity may be applied for a quantum of installed capacity proposed to be connected to ISTS less auxiliary power consumption. An applicant may apply for Connectivity after it registers itself at Central Repository with CEA.
- (c) The Committee finds that under the prevailing Regulations, the applicant, while applying for 'Connectivity to ISTS', is obligated to inform the following :

- (i) Site identification and status of land acquisition and possession
- (ii) Status of submission of proposal for Environmental clearance for the power station to the concerned administrative authority (first level submission).
- (iii) Status of submission of proposal for Forest Clearance (if applicable) for the land for the power station to the concerned administrative authority (first level submission).
- (iv) Fuel Arrangements: Details in regard to quantity of fuel required, percentage of fuel already tied up / proposed to be tied to generate power from the power station for the total installed capacity of the project
- (v) Water linkage: Status of approval from the concerned state irrigation department or any other relevant authority for the quantity of water required for the power station.

The Committee is of the view that aforesaid prerequisites are adequate for making an application for Connectivity.

- (d) The Committee is of the view that Connectivity is primarily for facilitating following
 - (i) the financial closure of new generation projects
 - (ii) planning of dedicated transmission line
 - (iii) take into account cost of dedicated transmission system in the estimated project cost
- (e) CTU may grant the Connectivity to the applicant but applicant should not be allowed physical connection with the grid before filing the application for GNA and

furnishing bank guarantee thereof. Application seeking GNA has to be filed within 2.5 years of date of grant of Connectivity by CTU, failing which Connectivity granted should be withdrawn and application fees should be forfeited. Applicant will have to file fresh application for Connectivity if it wishes to obtain the same.

(f) **Charges for Connectivity**

Few stakeholders have suggested that Connectivity should continue to be free and few have suggested that certain charges should be levied for Connectivity. The Committee has already suggested that application for only Connectivity should not survive and generator should have to mandatorily apply for GNA before it gets physically connected to the grid. However there may be a situation that generator is connected to ISTS for purpose of startup power/injection of infirm power before operationalization of GNA for which period it should be levied Reliability Support Charges. A generator should be charged Reliability charges for the installed capacity of unit post synchronization of the unit and as per the quantum of electricity drawl (under start up) approved by RLDC before synchronization.

6.12.2 Construction of Dedicated Line

- (a) The Regulations in vogue provide that for generating stations with capacity of more than 500 MW in case of thermal plants and with capacity more than 250 MW in case of renewable /hydro stations, dedicated line should be

considered by CTU under coordinated planning. However many stakeholders have suggested that dedicated line should be constructed by the generating company.

(b) Section 10 of Electricity Act 2003 provides as follows:

“Section 10. (Duties of generating companies): --- (1) Subject to the provisions of this Act, the duties of a generating company should be to establish, operate and maintain generating stations, tie-lines, sub-stations and dedicated transmission lines connected therewith in accordance with the provisions of this Act or the rules or regulations made thereunder.”

The above provides that it is a duty of generating company to construct dedicated line.

(c) The Committee is of the view that establishing dedicated lines should be responsibility of a generator as prescribed in the Act. Needless to mention that the generator can match the commissioning of dedicated line with the commissioning of its generating station.

(d) A generating station may also be planned to be connected at two different substations. In such case, the lines emanating from switchyard of the generating station to substation(s) of the inter-State Transmission Licensees including Deemed inter-State Transmission Licensees should be constructed by generators as dedicated lines.

(e) An Applicant should be required to construct Dedicated Line(s) to the point(s) of connection to ISTS to enable connectivity to the grid. In case CTU envisages dedicated lines as lines which should be required to enhance the

system reliability even if generation project does not come up or is delayed, CTU may consider such lines under coordinated transmission planning.

- (f) If a generator gets connected to dedicated line established by another generator, then such dedicated line may be considered as ISTS after obtaining transmission license on filing application with the Commission under CERC (Transmission License) Regulations.

6.12.3 Start date of Connectivity

Few stakeholders have suggested that Connectivity is required for the purpose of availing startup power from the grid. The Committee agrees with the suggestion. As per prevailing Connectivity Regulations, a generating unit can avail startup power 21 months before it is expected to be declared under commercial operation. A generating unit can avail startup power even when the Associated Transmission System for a generation project is not commissioned. Hence a generator may seek Connectivity prior to the anticipated date of its Commercial operation depending upon its requirement for startup power or injection of infirm power. Since the Connectivity lines should be built by a generator, it should be able to avail startup power on getting connected with the grid provided that it has applied for GNA and deposited requisite bank guarantee as suggested above. A generator will be allowed startup power only through dedicated line. However, in exceptional cases CTU in consultation with

RLDC/NLDC/CEA may consider drawal of startup power through LILO of existing lines.

6.12.4 Point of Commercial Metering

CEA Metering Regulations provide that metering should be done at interface point of connection with transmission system of licensee. In case Dedicated Lines are owned/constructed by a generator, such metering point will be at the pooling substation of ISTS licensee. In case generator is connected to more than one pooling station, there may be flow of power from one pooling station to other through generating station, thereby causing losses in Connectivity lines for incidental power flow. Hence it is suggested that metering should be at the bus bar of the generating station. The above provision of metering at bus bar should be implemented for existing stations also where dedicated lines have been built by generating stations so as to apply the Regulations uniformly to all generators.

6.12.5 Connectivity/GNA by a Captive Power Plant

A captive power plant may have surplus capacity which it may sell on long term/medium term/short term basis. It may also wish to draw power in case of shutdown of its generating units. It should pay transmission charges for the quantum of schedule drawal at POC rate applicable for the State in which it is located. In such a case the captive plant may apply for Connectivity for the maximum

injectable/maximum drawal capacity with ISTS. However, it may seek GNA for injectable capacity i.e. maximum surplus capacity which it would normally sell through ISTS. It may be allowed to sell power/buy power on obtaining LTA/ MTOA/ STOA as per the GNA sought. If its actual injection / drawal schedule exceeds respective GNA quantum by 120%, additional transmission charges should be levied. CPP may also draw emergency power for short duration in case of tripping of captive generating unit. Such a plant may be allowed to draw emergency power for short duration of upto 3 hrs equivalent to installed capacity of its largest unit for its captive load during the time the CPP is able to procure power under short term.

6.12.6 Application fees

The Committee notes that the Commission has, in the Statement of Reasons dated 30th October, 2009 given the basis of fixing application fee for Connectivity, MTOA and LTA as under:

34. In our view, the system studies involved in dealing with processing of applications for Medium Term open access are relatively simpler and less time consuming as the RLDCs are required to check only the system constraints, whereas stability and other studies would additionally be required for allowing connectivity and long term access. Accordingly, the application fee for Medium Term open access has been kept lower than the fee for the Grant of

connectivity and Long Term access for which more elaborate system studies and system planning studies are required to be made. Therefore, application fee for Long Term access and connectivity have been accordingly formulated of the same order. However, the application fees have been reduced for all categories depending upon the quantum of power to be injected in to ISTS or drawn from ISTS.

The above fee was fixed in 2009. The Committee is of the view that about 7 years having elapsed since then, an increase would be in order keeping in view of increase in manpower expenses (for carrying out system studies). Enhancement in application fees in comparison to the prevailing application fees would also be in order in view of the fact that Application Bank Guarantee along with the application is proposed to be dispensed with. Since construction of Dedicated Lines would be responsibility of the generator and application fees is proposed to be enhanced, no application bank guarantee would be necessary.

Accordingly, non-refundable Application Fee should be paid by the Generating Station / Bulk Consumer along with application for Connectivity and GNA as per details given below:

Application fees for Connectivity and GNA is proposed as follows:

Sl. No.	Quantum of Power to be injected/off taken into/from ISTS	Application fee/ (Rs. in Lakh)	
		For Connectivity	GNA
1.	Up to 100MW	4	4
2.	More than 100 MW and up to 500 MW	6	6
3.	More than 500 MW and up to 1000 MW	12	12
4.	More than 1000 MW	18	18

A generator shall apply for Connectivity and GNA once at the time of its inception whereas STUs shall apply for GNA every year for 5 year period. Hence the above Application fee should not be levied on STUs applying for GNA.

6.12.7 Access bank guarantee

- (a) The main issue is the amount of bank guarantee which could be considered as sufficient as bank guarantee to safeguard against the risk of stranded asset in case generation project fails to get commissioned.
- (b) The basic question in regard to amount of Bank Guarantee in the Staff Paper was whether to continue existing bank guarantee of Rs 5 lakh per MW despite transmission cost being of the order of Rs 1 cr per MW. The propositions in the Staff Paper in this regard were (i) BG equal to NPV of transmission charges for 12 years or 7 years (ii) BG at a flat rate of Rs X per MW of installed capacity as one time charge, (iii) Five years Average

Injection and withdrawal charge and (iv) Five years Average injection charges only.

- (c) Few stakeholders have suggested that existing bank guarantee of Rs. 5 lakh/ MW is sufficient and few have suggested that it should be equivalent to cost of transmission line or it should be equivalent to 2-5 years of estimated transmission charges. The purpose of bank guarantee is to safeguard recovery of charges for transmission which is already under execution for an Applicant and in case the generating plant gets delayed or is abandoned, the charges for transmission unutilized / underutilized due to its exit should not be passed on to other beneficiaries of the grid.
- (d) The existing BG for augmentation of transmission system is upto Rs. 5 Lakh/MW. Staff Paper recognised that BG of Rs. 5 lac/MW is grossly inadequate to cover investment by transmission licensee. POWERGRID and GUVNL have stated that BG should be equivalent to 12 years transmission charges. POSOCO has stated that Bank Guarantee amount should be sufficient to bring in seriousness regarding entry as well as exit. Few generators have stated that BG amount shall be equivalent to 3 to 5 years of transmission charges payable for the GNA capacity. We have perused data of POWERGRID system for a few projects where the cost of associated transmission system varies from Rs. 5 lacs/MW to Rs. 90 Lacs/MW. The monthly transmission charge for Q2 2016-17 is approx. Rs. 2100 Crore and

LTA+MTOA among which this is divided is approx. 80,000 MW. Hence the average transmission charge is Rs. 2.6 lacs/MW/month which approximates to Rs. 31 lac /MW/year. However the Committee has proposed that the construction of the dedicated line for all the generators should now be the responsibility of the generating company. Further, in the proposed arrangement the generator will be able to schedule any power only when it obtains GNA. Most of the issue of relinquishment of LTA was due to the existing system of LTA with target region which has since been revised. The Committee has also seen that abandoning of LTA was in case of less than 2% of capacity addition in the country. Keeping all these factors in view, the Committee suggests that BG should be approximately equal to one year transmission charges. Since the Committee has already recommended that dedicated lines should be responsibility of generator, the Committee suggests that Access bank guarantee may be considered as Rs. 20 lac/MW. The Access Bank Guarantee should be kept subsisting for 12 years from the date of operationalisation of GNA. After operationalisation of GNA, Access BG equivalent to 1/5th of amount should be returned back to the Applicant till 4th year. The amount equivalent to 1/5th of Access BG should be kept subsisting till the end of 12th year as security towards relinquishment charges. It is expected that in a power system with the growth as it is being witnessed in the country at present, spare transmission capacities created

if any due to exit of a generator in pooled network would get utilized to some extent.

- (e) In case, GNA application is not accompanied with adequate Bank Guarantee, the application should be considered incomplete and should be rejected.
- (f) Access bank guarantee shall not be required to be paid by STUs.

6.12.8 Encashment /Discharge of bank Guarantee

- (a) The quantum of Access Bank Guarantee should be progressively reduced each year after operationalisation of GNA corresponding to the one fifth of its total value. Each year one fifth of the value of Access bank guarantee should be returned to the Applicant till 4th year. The amount equivalent to 1/5th of Access BG should be kept subsisting till the end of 12th year as security towards relinquishment charges.
- (b) If GNA Customer seeks an exit (fully or partly) or abandons the generation project or relinquishes GNA at any stage after placement of LOA or order to a successful bidder under TBCB route by bid process coordinator or placement of LOA to contractor by POWERGRID for transmission system to be developed by POWERGRID on nomination basis of Transmission System associated with that GNA either partly or fully, the bank guarantee subsisting should be encashed.

6.12.9 Charges in case of exit/downscale of GNA after commissioning

- (a) Stakeholders have suggested that a onetime charge should be specified for cases of exit since CTU has expressed its inability to determine stranded capacity in a meshed network. It has also been suggested that 3-5 years injection and withdrawal charges may be considered.
- (b) The Committee is of the view that any downscaling of GNA should not be allowed for units which are running except if unit gets non-functional due to force majeure conditions. Further calculation of exit charges on the basis of estimated charges for future years should be difficult to estimate. Hence the charges for exit should be known upfront to a generator. In case a generator wishes to exit from GNA it should be disconnected from the grid. In case it exits prior to completion of 5 years after GNA is operationalized, the remaining / available Access Bank Guarantee be encashed by CTU towards exit charges. In addition the generator should be liable to pay transmission charges for one year (as per prevailing POC rate for the generator in case rate is available for the generator, else all India average POC rate) towards exit charges. In case it exits after 5 years, the generator should be liable to pay transmission charges for one year (as per prevailing POC rate for the generator in case rate is available for the generator, else average POC rate) towards exit charges. However in case there are pending

applications for GNA seeking same corridor, exit charges should not be leviable on the generator to the extent corridor is reallocated to other seekers.

- (c) A generator may derate its units due to technical issues in which case it should be allowed downscaling of GNA without any charges.

6.12.10 Treatment of delay in Transmission system / Generation projects

- (a) In order to monitor/ review the progress of generating units along with its direct evacuation lines and also the common transmission system, Joint Co-ordination meeting with the representative of each developer, CTU and transmission licensees should be held at regular intervals (preferably quarterly) after grant of GNA as prevailing.
- (b) In case any of the developer fails to construct the generating station /dedicated transmission system or makes an exit or abandon its project, CTU should have the right to encash the bank guarantee.
- (c) In case of adverse progress of individual generating unit(s) /expected delay of generators assessed during coordination meeting, CTU should endeavour to re-plan the system if the augmentation system has already not been awarded. In case the augmentation system has already been awarded and generator seeks deferment of start of GNA, no such deferment should be granted and the generator should be liable to pay full transmission

charges from the date of operationalisation of GNA or commissioning of the related transmission system whichever is later.

- (d) In the event of delay in commissioning of concerned transmission system from its scheduled date, CTU should make alternate arrangement for dispatch of power at the cost of the transmission licensee. The interim arrangement so provided should be removed with commissioning of actual planned system.
- (e) In case such alternative arrangement cannot be provided the transmission licensee should pay proportionate transmission charges as per its TSA which should be provided to generator as compensation in case generator is ready and line is not ready. Such payment from the transmission licensee may be recovered from the Contract Performance Guarantee furnished by the transmission licensee.

6.12.11 Treatment of payment of charges in case of non-availability/delay in upstream /downstream system.

- (i) 'Upstream system' means the end bays/ transmission lines at same or higher voltage associated with a transmission line without commissioning of which the transmission line cannot be in regular service. 'Downstream system' for a transmission line means the terminating bays/ transmission lines at same or lower voltage associated with a transmission line without commissioning of which the transmission line cannot be in regular service. It has been observed that in few cases

downstream system of states to be built by STUs is not available matching commissioning with ISTS lines due to which ISTS remains unutilised/ doesn't serve intended purpose. The issue was discussed with representatives of States during Committee Meetings where few states suggested that in such cases charges for associated ISTS may be charged to the DISCOM for whom the associated ISTS has been built. Few states have suggested that compensation should be covered under a mutual agreement between both the transmission licensees. States have also stated that in case CTU system is not ready and State system is ready CTU should also be liable to pay compensation to State. CERC has already issued Suo Motu Order 11/SM/2014 dated 5.8.2015 whereby following is directed:

"Keeping in view the mismatch between commissioning of transmission system by an ISTS licensee and upstream/downstream system of STU, we are of the view that ISTS transmission licensees and STUs should also sign such Implementation Agreement for development of ISTS and downstream system in coordinated way to avoid any mismatch.

.....

Concerned STU, who had requested for provision of downstream line bays in the various meetings of Standing Committee/RPC, should bear the transmission charges till completion of downstream system."

- (ii) Gujarat has stated that STU doesn't have any agreement with ISTS licensee and it is the DISCOM who should be liable to pay the transmission charges.
- (iii) Accordingly Committee is of the view that ISTS licensee, CTU, STU, associated State transmission licensee; DISCOM should enter into indemnification agreement to agree upon payment of charges in case of delay by ISTS licensee/ State transmission licensee. In the absence of indemnification agreement the payment liability should fall on entity due to which an element is not put to use. For e.g., Line is ready but terminal bays belonging to other licensees are not ready, the owner of terminal bays should pay the charges to line owner in a ratio of 50:50 till the bays are commissioned. In case one end bays are commissioned, the owner of other end bays should pay the entire transmission charges of the line till its bays are commissioned.
- (iv) Further CTU may coordinate with STU to ensure that ordering for state lines are done such that it is commissioned matching with ISTS lines. The ISTS system should be included under POC calculations only after it is put to use. The Committee feels that there is a need of planning State systems along with ISTS. A State Power Committee similar to Regional Power Committee may be established at State level to coordinate issues affecting state involving all stakeholders within States.

6.12.12 Utilisation of congestion charges

- (a) The Staff Paper raised an issue whether congestion charges should be utilised for reduction of long term ISTS transmission charges or they should be utilized for creation of specific transmission assets for relieving the congestion and whether it should be treated as equity, loan or grant.
- (b) Stakeholders have suggested that congestion charges should be used to reduce transmission tariff or may be used to fund new projects to relieve congestion in form of loan / grant.
- (c) CERC has notified Power System Development Fund (PSDF) Regulations in July, 2014. The congestion charges also form part of PSDF and are being utilised for various purposes (like transmission systems of strategic importance for relieving congestion, compensation devices for improving voltage profile, standard and special protection schemes, setting right the discrepancies found in protection audit on regional basis, capacity building, technical studies, installation of PMUs, etc.
- (d) CERC has in Order in Petition no. 129/MP/2012 directed that PGCIL to make an application before the Managing Committee of PSDF for reimbursement of funds equivalent to the loan amount for installation of PMUs.

- (e) CERC has in petition no. 67/TT/2015 also directed POWERGRID to seek funds from PSDF Fund to reduce the cost of the assets and consequently, the transmission tariff of Biswanath-Chariyali-Agra HVDC Link.
- (f) Thus Congestion charges are already being utilised and the utilisation has found acceptance among the stakeholders.
- (g) GOI has also decided for support from PSDF for use of imported e-RLNG in gas based stations.
- (h) We suggest that congestion charges may be utilised as provided in CERC (Power System Development Fund) Regulations 2014 as amended from time to time.

6.12.13 Transmission Corridor Allocation for power markets

- (a) Few stakeholders have supported the idea of booking of corridor for participants of power exchange and few have opposed the idea.
- (b) The Committee feels that in a power exchange point to point transaction cannot be ascribed since it is not a bilateral transaction. Hence booking of corridor would be subject to speculations and gaming. Hence booking of corridor by participants is not recommended. However it is recommended that 5% of each flow gate may be booked for day ahead collective transactions which may be released for contingency market in case of non utilisation the corridor by exchanges. The percentage of booking may be reviewed after one year of operation.

6.13 Technical aspects to be considered while Planning of ISTS

- (a) Central Electricity Authority (CEA) prepares the “Perspective Plan for Power” based on “Annual Power Survey” while CTU executes the Planning of Transmission lines for evacuating power from the integrated power plants in the integrated All India Synchronous Grid.
- (b) Earlier the power system planning was done on regional self-sufficiency basis involving all the five Electrical Regions in India and any surplus or deficit was managed through interconnected power flow. From about 1994 the power generation has witnessed major developments through Public and Private sector power plants and affected the evacuation/transmission system in the grid. The transformation from Regional Grids to all India-Synchronous grid and the development of hybrid network with bulk power evacuation through HVDC system have expanded the network, and the density of network has increased. This has resulted in more transmission lines in some areas while some other areas suffer constraints due to inadequate or inapt transmission.
- (c) The planning criteria, adopted in India, has so far been deterministic, although probabilistic considerations are being considered but good amount of data acquisition

regarding growth expansion in generation and transmission need collation for use in Planning.

- (d) It has been felt that normal planning practice needs extensive studies that include load flow and stability simulations with numerous outage contingencies based on grid operation and reliability as also system security considerations for such a vast synchronous grid. It is worth noting that both these organizations have, as on date, necessary tools to carry out these types of studies and these tools are being upgraded continually.
- (e) Even though these two organizations have at their disposal advanced software/tools to perform system planning studies both these organizations suffer from acute and chronic shortage of skilled and trained engineering manpower. The available resources are too meagre and requires strengthening to undertake such an enormous task on their own, at this time. A look into the corresponding figures of the System Studies department in China and Brazil staffed with highly qualified experts, with advanced training possessing M. Tech and Ph. D. in various disciplines of power system planning that includes technical, financial and commercial aspects, and handle extensive generation expansion with associated transmission studies as per international standards and practices. The expertise cannot be built overnight and the engineering team to handle the Indian power system planning need good amount of planned training before they can be entrusted to handle

proper system studies to meet the challenge of power evacuation to the same degree of reliability and security standards that are followed in the industrialized countries. It is not an understatement to say as to how much is needed to supplement the power system departments of CEA and CTU to meet such a challenge. The Administration/Government responsible for both CEA and PGCIL has to look into such shortages as fast as possible and plan their specialized training so that the All Indian Synchronous Grid can be planned and built to meet high standards; if not, then system planning in India would continue to suffer and will continue to be insecure leading to uneconomical and unreliable system. Now reverting to technical aspect of system planning in India the committee feels that following be incorporated in the System Planning Criteria on 2013 which, in itself, is quite exhaustive.

- (f) CTU should carry out systematic load flow studies covering all credible contingencies with possible voltage constraints. It is also important to execute and determine the load characteristic in relation to frequency and voltage parameters. This should be jointly done by PGCIL and POSOCO with the association of CPRI and IITs. At present we are using the load characteristics (PQ Versus V and f) as defined by Kundur or PTI and this may not be realistic to the Indian Grid.
- (g) The Dynamic Stability Studies of heavily loaded transmission system with High Gain Static Excitation

system along with PSS and Limiters in action should be carried out.

- (h) Voltage Stability Studies should be done in detail. In this connection it is advised that CEA and CTU in particular should refer to WSCC Document entitled “Voltage Stability Criteria, Undervoltage Load Shedding and Reactive Power Reserve Monitoring” issued in 1998. This document was a result of findings of two major grid disturbances that took place in July/August 1996, similar to what Indian Power System experienced in July 2012. This document defines very well the methodology of conducting reactive power studies and reactive power reserve margins. The development of VQ curves under the worst contingency has been described in detail.
- (i) It is necessary to evaluate the impact of SCR and Inertia Constants of large size generators in the Public and Private Sectors on load-ability of lines. Refer to a classic paper by Kimbark-Clark diagram that shows the steady state stability limits as influenced by loads and reactive sources at intermediate busbars.
- (j) The liberal application of reactive sources on the lines in the form of shunt reactors, passive and dynamic compensation and in special cases use of Phase Angle Regulators at strategic nodes to control the loop power flows and optimize the loadings on lines needs to be addressed. The line connected shunt reactors applied on EHV lines are essential part of the line and should not be disconnected. If required the same lines could be

provided with SC or TCSC as the case may be to maintain an acceptable voltage profile.

- (k) It is strongly felt that appropriate allocation of shunt reactors on transmission lines as un-switched reactors, switched reactors on EHV busbars and MV reactors on tertiary winding of ICT should be managed in an approved sequence so that the EHV lines and the power system maintain the normal voltage profile within limits.
- (l) Besides the passive shunt reactors provided in the system as indicated above, the need of dynamic support in the form of SVC or STATCOM is warranted to take care of post-fault developments. The quantum of dynamic resources in the form of SVC and STATCOM would be over and above the quantum of passive compensation provided and as a thumb rule it could be around 50 % of passive capacitive resources. Such provision of dynamic resources is quite normal and practiced all around the developed world.
- (m) Appropriate management of dynamic resources must consider the necessity of “assured” quantum of dynamic compensation. In this connection attention may be drawn to a paper “ Static Compensators and their relation to system stability” by Tanguay and McGillis from Hydro-Quebec indicating the methodology to determine the number of SVCs required in addition to that considered in System studies. This is important as several fairly large sized and good number of SVC/STATCOMs have been planned in the Indian

network and their availability and system reliability has to be assured.

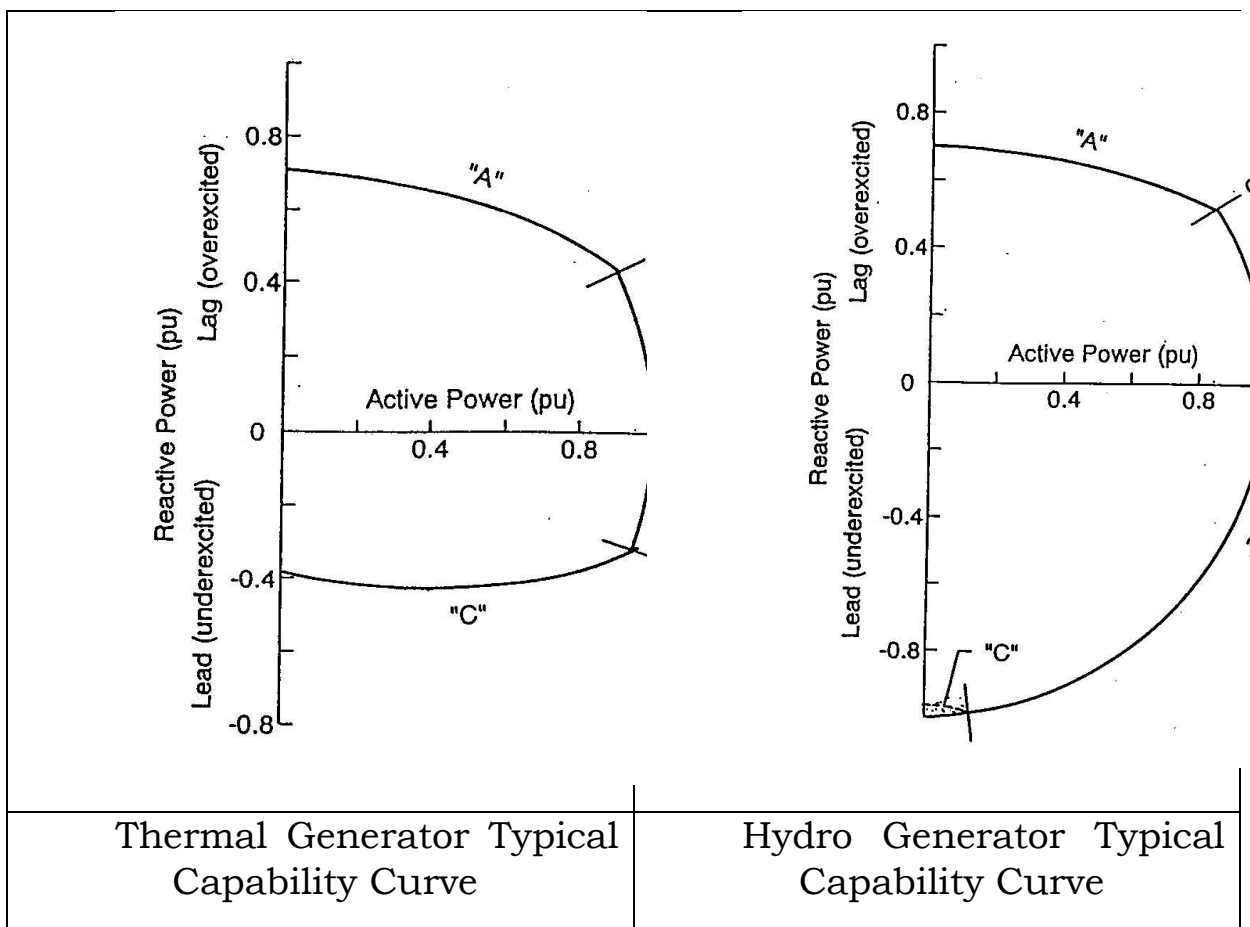
- (n) There should not be any confusion of load-ability limits of EHV transmission lines. In Integrated grid operation with appropriate compensation prevalent wind and temperature conditions under peak load period no constraints on the load flow limits on the line is expected and depending upon the weather and temperature conditions, the line loading can exceed the thermal limits.
- (o) In all these efforts in adaptation of latest techniques and software for system studies by CEA, PGCIL and POSOCO, it may be desirable some assistance is taken from reputed consultants like Hydro-Quebec, Teshmont, RBJ all from Canada and PRDC from India with whom PGCIL had good exposure.
- (p) CEA, Transmission Planning Criteria provides that during operation, following the instructions of the System Operator, the generating units shall operate at leading power factor as per their respective capability curves. In this regard a short description on understanding of Generator Capability Curves is as detailed below:
 - (i) The Supplier of Generating units furnish the Generator Capability or Performance Curves that indicate Power output, Maximum Stator Current, Maximum Rotor current, maximum lagging output, leading reactive power output, rotor angle limiter and end-iron heating

limit. This is the Capability Curve defined by limiting values. For practical operational purposes realistic output of P and Q over the full range of power factor should be prepared by the Plant Operator and use as Operating Instructions for the power plant.

- (ii) The rated power factor of all the Generating Units installed so far has been 0.85 lagging with given rated output P at this Power factor. The corresponding Q output is around 55% of rated MVA of machine. Although the unit can supply lagging Vars to the system to the tune of 55% but this is not practical, especially with generators remote from load centres, as the lagging Var requirements of the load have to be met and managed locally and not transported over the system. Such transportation will be creating more power loss and affect the voltage profile. This results into a situation where the Generators are operated at about 0.95 instead of 0.85 pf lagging. Such operation results into loss of about 15-20% in the stability margin. See reference [1].
- (iii) The Turbo-Generators with SCR around 0.5 have limited MVAR absorption capabilities and that too is restricted by end-iron heating, rotor angle limiter of around 75° and further need of keeping an operating margin of atleast 10%. This means under steady state operating conditions the thermal has limited reactive power absorption capability. With restraints of Quadrature Axis Vibration, the loading pattern on

Generator becomes quite restrictive and should not be violated without endangering the life of the Generating units.

- (iv) To meet such operational requirements of the network, the system must be provided with suitable reactive power absorption devices, especially under light load conditions.



- (q) There is a need to assess the Available Transfer Capacity (ATC) of existing system through independent experts. It is recommended that Commission may entrust the task to third party for independent assessment of ATC for existing system and measures that can be employed to enhance the

transfer capability of existing system may be through SVCs/STATCOMs etc.

6.14 Other Issues in regards to ISTS

The Committee while discussions came across issues which have not been raised directly in Staff paper but needs to be addressed. The Committee has accordingly included them herein:

6.14.1 Sale of surplus power by States

GRIDCO has stated that GNA Mechanism does not speak out on the issue of sale of surplus power by the States for which even if the states will declare their injection GNA as there is no prescribed mechanism for such sale. In this regard a state may seek injection GNA and drawl GNA separately. A state may like to sell power for a few hours in a day and draw for rest of the hours. It may seek STOA accordingly. Committee also notes that many states are involved in Banking mechanism in which case a State sells power in a particular season and takes back same in other season. A state has power from its own stations and the contracted power from ISGS. A state may like to sell power from its contracted power from ISGS. However currently there is no such provision through which a State may sell its share of contracted power from an ISGS at injection point of ISGS. The Committee recommends that necessary provision may be made in the Regulations to enable a State to sell power

out of its contracted power from ISGS at injection point of ISGS.

6.14.2 Demand Forecasting by States

The essence of seeking GNA by States lies in accurate demand forecasting by States. There is an imminent need for handholding of States for accurate demand forecasting. It is suggested that CEA and CTU should handhold states for demand forecasting. It is also suggested that States should procure software for short term/medium term and long term demand forecasting. The State Regulator may allow the expenditure towards procurement of software in their ARR. This work may be undertaken by the proposed State Power Committee.

6.14.3 Formation of State Standing Committee

Committee suggests that there is a need of formation of state level standing committee to take up transmission planning within the state to ensure that transmission system within the state is planned and commissioned matching with inter-state transmission system.

6.14.4 Formation of State Power Committee

A State Power Committee similar to Regional Power Committee may be established at State level to coordinate issues affecting state involving all stakeholders within States. Such a committee should coordinate between STU and DISCOMs for assessment of GNA and between SLDC and DISCOMs for demand/load

forecasting. Such a Committee may also see that State has a balanced purchase portfolio. There should also be need of coordination between Regional Power Committee and State Power Committee. A forum on the lines of Forum of Regulators (which coordinates between (CERC and SERC) may be created for interaction between RPCs and State Power Committees within a region.

6.14.5 Draft Regulations

The Terms of Reference provides for regulatory intervention with Draft Regulations. The Committee has recommended considerable changes in the transmission planning and terms and conditions of Connectivity and Long Term Access, Medium Term Open Access and Short Term Open Access and feels that the exercise for preparing draft regulations could be undertaken after in-principle acceptance of its recommendations. The Commission may like to amend existing Regulations or notify new Regulations and direct the Staff of the Commission accordingly.

CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC)
3rd & 4th Floor, Chandralok Building, 36, Janpath, New Delhi-110 001
Tel.:23753920 / Fax: 23753923

No. Engg./DP – Transmission/2014-CERC

Dated 8.12.2015

Subject: Constitution of Committee to “Review Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues”

Central Electricity Regulatory Commission (CERC) has decided to constitute a Committee to review “Transmission Planning, Connectivity, Long Term Access, Medium Term Open Access and other related issues”.

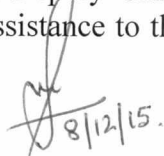
2. The Committee has been constituted having ^{the} following members:-

- | | | |
|--|---|----------|
| i. Shri Mata Prasad, Power System Expert | - | Chairman |
| ii. Shri Rakesh Nath, Former Member, APTEL | - | Member |
| iii. Shri A.S. Bakshi, Member, CERC | - | Member |

3. The scope of work of the Committee is as follows:-

- To study the CERC Staff Paper on Transmission Planning, Connectivity, Long Term Access and Medium Term Open Access;
- To analyse of the comments received in response to the above staff paper;
- To suggest an appropriate regulatory intervention with a draft regulation.

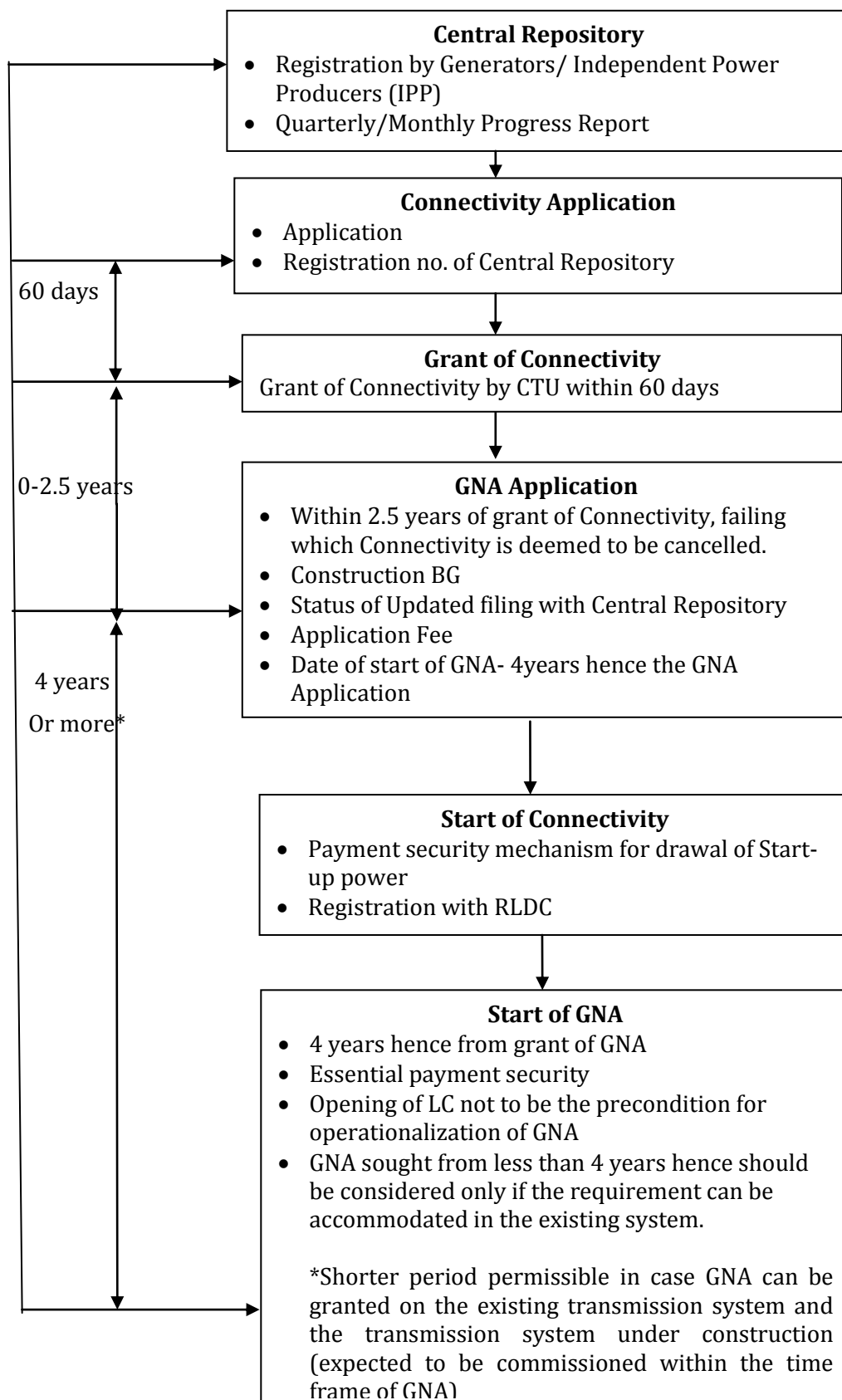
4. The Committee may complete the task within three months. While carrying out the task, the Committee may co-opt or consult any person / expert / institution / organization and seek assistance, advise, opinion in the subject matter. Mrs. Shilpa Agarwal, Deputy Chief (Engg.), CERC will assist the Committee as its Nodal Officer and secretarial assistance to the Committee will be provided by the Engg. Division of CERC.


(Shubha Sarma)
Secretary

To

- | | | |
|--|---|---------------|
| i. Shri Mata Prasad, Power System Expert | - | Chairman |
| ii. Shri Rakesh Nath, Former Member, APTEL | - | Member |
| iii. Shri A.S. Bakshi, Member, CERC | - | Member |
| iv. Mrs. Shilpa Agarwal, DC (Engg.), CERC | - | Nodal Officer |

Process of GNA/Connectivity



BIBLIOGRAPHY

- [1] Tanguay and McGillis, “Static Compensators and their relation to System Stability” (Hydro-Quebec).
- [2] Voltage Stability Criteria, Under voltage Load Shedding and Reactive Power Reserve Monitoring (WSCC, 1998).
- [3] E. W. Kiambark, “Improvement of System Stability by Switched Series Capacitors” (IEEE, February, 1966).
- [4] Manual on Transmission Planning Criteria, (CEA, January, 2013).
- [5] Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 (CERC, July, 2009).
- [6] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 (CERC, April, 2010).
- [7] Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service (FERC, February, 2007).
- [8] Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities (FERC, July, 2011).
- [9] SB Farnham and RW Swarthout, “Field Excitation in Relation to Machine and System Operation”: AIEE paper no 53-387.
- [10] Estimating Generator Capability Curves : University of Wisconsin Madison USA.
- [11] Niazy, Mortazavi, Ebadi and Sabzevari, “Considering Synchronous Generator Capability Curve Variations for Reactive Power Market”.