Chapter - 3

Planning of transmission system

3.1 Planning process of transmission projects

Inter-state Transmission system (ISTS) is planned by PGCIL on the basis of requests for long term access (LTA) received from Inter-State Generating Stations and inputs from POSOCO/ State Utilities/ CEA. On the basis of such inputs, power system studies are carried out by PGCIL either for evacuation of power from new generation project or for strengthening of transmission system/ removal of transmission constraints as required. The proposals for transmission schemes, including results of studies, are brought out in the form of Agenda at the meeting of Standing Committee for Power System Planning (SCPSP)[16] of the concerned regions. The proposal for a new transmission scheme is technically approved by the SCPSP. Empowered Committee on Transmission, under the chairmanship of Member (Power System), CEA, discusses and recommends to Ministry for implementation of transmission elements either through Tariff Based Competitive Bidding (TBCB) or through cost plus basis by PGCIL as per Tariff Policy. After approval of Ministry of Power for nomination of PGCIL for execution of project on cost plus basis, PGCIL prepares Detailed Project Report (DPR), which is submitted to CMD/ BOD for investment approval. Detailed planning process is explained in ***Annexure 2.*** Audit examined the planning process of PGCIL and observed the following inadequacies:

3.2 Deficiencies in planning of Transmission system

3.2.1 Absence of Network Plan

As per the provisions of Electricity Act 2003, CEA has been entrusted with the responsibility of preparing National Electricity Plan (NEP) for both generation and transmission. CTU is mandated to discharge all functions of planning and co-ordination relating to inter-state transmission system and to ensure development of an efficient, coordinated and economical system of inter-State transmission lines for smooth flow of electricity. As per National Electricity Policy 2005, CTU has the key responsibility of network planning and development based on the NEP, 2012 in coordination with all concerned agencies.

Further, as per Guidelines for encouraging competition in development of transmission projects (April 2006) of Ministry of Power, CTU has the key responsibility of network planning and development based on NEP in coordination with concerned agencies. The practice of carrying out network

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[16] ***SCPSP for each region is constituted by CEA for carrying out its duties of integrated planning under section 73 (a) of the Electricity Act, 2003. These committees are headed by Member CEA and have representative of Central Transmission Utilities, State Transmission Utilities, Central Generating Units (CGUs) etc. as members. SCPSP provides technical approval to the projects***

planning by the Government/ Transmission Companies was noticed in different countries[17]. Network Plan is required to include (i) projects for new transmission lines and substations and (ii) strengthening and upgradation of existing lines. Guidelines further added that network plan will be hosted on the website of the CTU and is to be reviewed and updated as and when required but not later than once a year.

In compliance with the above provisions, CEA notified NEP (November 2012) for generation and transmission capacity addition during 2012-17. However, audit observed that no Network Plan was found available in the records or on the website of CTU.

Due to absence of Network Plan, a structured mechanism for timely dissemination of the likely additions/ modifications to the transmission system to stakeholders, and for assessing and focusing on the requirement for upgradation of the existing lines in advance was not available as discussed in the subsequent para.

In the Exit Conference with Ministry, Management stated (January 2020) that as per Electricity Act, CEA is to formulate short term and perspective plan and in this exercise, CTU extends necessary support in preparation of comprehensive network plan. Based on NEP and inputs from stakeholders, schemes were finalised and discussed in the Standing Committee from time to time and implemented. Planning of annual transmission network beforehand may not be possible as it depends on various inputs from stakeholders.

Reply of Management/ is not acceptable because as per the guidelines of Ministry, CEA was to prepare perspective plan whereas CTU was to prepare Network Plan based on perspective plan for implementation, and host the same on the website which was not done. Internationally also, for example in United Kingdom[18](UK), network planning is carried out annually by their system operator.

3.2.1.1 Non-availability of timely information to stake holders about new projects

Audit observed that as per the 12th five year plan 2012-17, PGCIL had planned to execute 162 projects during that period. However, 182 unplanned projects were also executed while 41 planned projects were not undertaken, making a total execution of 303 projects by March 2017. But these changes were nowhere reflected as part of any network plan. A professional approach to planning requires that additional schemes be conceived at the beginning of each financial year and the information be disseminated for the information of stakeholders. In the absence of annual plan, the overall transmission plan becomes an aggregation of additional plans approved in each meeting of the SCPSP and there is a

17 ***As per Power and Energy Journal Volume 14 Number 4 July August 2016 of Institute of Electrical and Electronics Engineers, USA***

18 ***National Grid ESO is the electricity system operator of UK published Forward Plan 2020-21, which apart from other things included system insight, Planning and Network development***

possibility that each individual scheme would focus on addressing the immediate issue, thereby, compromising the larger perspective of an economical and optimum transmission plan.

A well-defined Network Plan to map these changes on an annual basis, which was hosted on the website would have provided timely and useful information to the STUs and other stakeholders (States/ Centre regulators, generator and DISCOMs). Besides, this would have included measures being taken up by PGCIL for enhancement of inter-regional and inter-state power transfer capacity and removing transmission constraints, which would be of added value. A proper network plan and its dissemination would help strengthen the mechanism for the CTU to discharge its coordination role as mandated in the Electricity Act. This would aid in reducing the possibilities of mismatch of the transmission system with linkages of other stakeholders like generators and STUs, etc. Few instances of mismatch of the transmission system of PGCIL with generators and STUs are highlighted in Para 3.2.2 in this Report.

3.2.2 Mismatch of planning of transmission lines

3.2.2.1 Mismatch in planning transmission lines for evacuation of power from generation projects

National Electricity Policy, 2005 requires that while planning new generation capacities, requirement of associated transmission capacity would need to be worked out simultaneously in order to avoid mismatch between generation capacity and transmission facilities. CERC regulations on "Grant of Connectivity, Long Term Access and Medium Term Open Access" also allow injection of infirm power *(i.e.* power generated by a power station prior to its date of commercial operation) by a generating station into transmission system six months prior to its commissioning. Therefore, transmission system associated with a generation project should precede the date of commercial operation of the generating station at least by six months.

Out of 11 generation linked transmission projects selected in audit, eight projects were completed till July 2018. Out of these eight projects there was delay in commissioning of six transmission systems associated with generation projects in the States of Chhattisgarh, West Bengal and Odisha due to which there was congestion in evacuation of power. Details of generation projects and associated transmission projects are discussed in Table 3.1.

Table 3.1

Sl. No.	Name of Transmission projects/ generating Projects	Installed capacity (In MW)	Scheduled Commissioning of Generation Project	Scheduled Commissioning of Transmission Project	Actual commissioning of Generation Project	Actual commissioning of Transmission Project
(i) System strengthening in North/ West part of WR for IPP projects in Chhattisgarh, (ii) System strengthening in western part of WR for IPPs in Chhattisgarh and (iii) WR – NR HVDC Interconnector for IPP Projects in Chhattisgarh.						
1	RKM Powergen Ltd. (4x360)	1,440	June 2011 onwards	July 2014 to June 2015	October 2015	Sept 2017 to Dec 2017
2	Athenea Chhattisgarh Power Ltd. (2x600)	1,200	June 2013 onwards	July 2014 to June 2015	Not commissioned	Sept 2017 to Dec 2017
3	Jindal Power Ltd. (4x600)	2,400	March 2012 onwards	July 2014 to June 2015	September 2013	Sept 2017 to Dec 2017
4	Jindal Power Ltd. (225 MW Dongamahua CPP + 175 MW Tamnar TPS	400	July 2010, Existing	July 2014 to June 2015	Existing	Sept 2017 to Dec 2017
5	SKS Power Gen. Ltd. (4x300)	1,200	December 2012 onwards	July 2014 to June 2015	April 2017	Sept 2017 to Dec 2017
6	Korba West Power Co. Ltd. (1x600)	600	Nov 2012	July 2014 to June 2015	March 2013	Sept 2017 to Dec 2017
7	DB Power Ltd. (2x600)	1,200	October 2013	July 2014 to June 2015	October 2013	Sept 2017 to Dec 2017
8	KSK Mahanadi Power Co. Ltd (6x600)	3,600	February 2012 onwards	July 2014 to June 2015	August 2013	Sept 2017 to Dec 2017
9	BALCO (4x300)	1,200	October 2010 onwards	July 2014 to June 2015	October 2011 (interim arrangement started)	Sept 2017 to Dec 2017
10	Vandana Vidyut Ltd. (2x135+1x270)	540	Jan 2012 onwards	July 2014 to June 2015	December 2013	Sept 2017 to Dec 2017
11	Lanco Amarkantak Power Pvt. Ltd (2x660)	1,320	Jan 2012 onwards	July 2014 to June 2015	Not yet commissioned	Sept 2017 to Dec 2017
12	Chhattisgarh Steel & Power Ltd. (1x35+1x250)	285	June 2013	July 2014 to June 2015	Not yet commissioned	Sept 2017 to Dec 2017
13	Chhattisgarh state Power Tr. Co. Ltd.			July 2014 to June 2015	-	Sept 2017 to Dec 2017
14	GMR Chhattisgarh Energy	1,370	August 2013 onwards	July 2014 to June 2015	February 2015	Sept 2017 to Dec 2017
(iv) Transmission system for Phase –I generation projects in Orissa (Part C)						
1	Sterlite Energy Ltd.	2,400	June 2010	March 2014	October 2010	August 2015
2	GMR Kamalanga Energy Ltd.	1,050	November 2011	March 2014	March 2013	August 2015
3	Navbharat Power Pvt. Ltd.	1,050	March 2012	March 2014	Not commissioned	August 2015
4	Monet Power Company Ltd.	1,050	July 2012	March 2014	Not commissioned	August 2015
5	Jindal India Thermal Power Ltd.	1,200	March 2012	March 2014	May 2014	August 2015
6	Lanco Babandh Power Pvt. Ltd.	2,640	December 2013	March 2014	Not commissioned	August 2015
7	Ind Barath Energy (Utkal) Ltd.	700	December 2011	March 2014	Feb 2016	August 2015

Sl. No.	Name of Transmission projects/ generating Projects	Installed capacity (In MW)	Scheduled Commissioning of Generation Project	Scheduled Commissioning of Transmission Project	Actual commissioning of Generation Project	Actual commissioning of Transmission Project
(v) Transmission project for Ph-I Generation projects in Jharkhand and West Bengal Part A2 (vi) Transmission project for Ph-I Generation projects in Jharkhand and West Bengal Part B						
1	Adhunik Power	540	January 2012	August 2014 and October 2014	November 2012	April 2016 and October 2016
2	Essar Power (Jharkhand)	1,200	March 2013	August 2014 and October 2014	Uncertain	April 2016 and October 2016
3	Corporate Power Ph-I & II	1,080	September/ December 2013	August 2014 and October 2014	Uncertain	April 2016 and October 2016
4	West Bengal State Electricity Transmission/ Generation	1,000	Progressively by 2014-15	August 2014 and October 2014	-	April 2016 and October 2016

It can be seen from Table 3.1 that there was a clear mismatch between the scheduled commissioning of transmission system (March 2014 and June 2015) for the above projects vis à vis scheduled commissioning of the generating stations (June 2010 to December 2013), which was not in conformity with the requirements of the CERC Regulations. In addition to delay in planning the transmission projects, there were further delays in the execution of these transmission projects as none of the above transmission projects was commissioned as per their scheduled commissioning dates. There was a delay of eight months to one year in preparation and approval of DPR for these projects from the timelines fixed as per PGCIL's policy. Moreover, PGCIL took around 7-14 months for submitting application for forest clearance after investment approvals in the above six transmission projects. Accordingly, execution of the transmission projects was delayed even beyond their scheduled completion dates. Thus, generation projects were actually commissioned while the corresponding transmission projects were not ready to evacuate their power. Resultantly, interim arrangements had to be made for 21 to 56 months to evacuate the power produced by generating stations as given in Table 3.2.

Table 3.2

Sl. No.	Generation projects	Capacity	Period of interim arrangements
1	RKM Powergen Pvt. Ltd.	4X360 MW	Sep 14 to June 16
2	Korba West Power Co. Ltd.	1X600 MW	Feb 13 to April 16
3	KSK Mahanadi Power Co. Ltd.	6X600 MW	Aug 12 to Dec 16
4	BALCO	4X300 MW	Oct 11 to June 16
5	Vandana Vidyut	2X135MW+270MW	July 12 to March 17

Interim arrangements for injecting power disturbs power flow patterns, reduces reliability and can cause overloading of the transmission lines. Moreover, operational feedbacks submitted (February 2014 and January 2016) by POSOCO highlighted that non-availability of transmission system planned for evacuation of power from generation projects like Vandana Vidyut, KSK Mahanadi Power Co. Ltd, Korba West Power Co. Ltd, BALCO and Sterlite power projects, resulted in transmission constraints in Chhatisgarh and adjoining areas.

Management/ Ministry stated (January/ June 2019) that in some cases the applications for long term open access were received with a very small time gap of two to three years between date of application and the year of commissioning of generating units whereas implementation of transmission system generally takes about three to four years from the date of award. Accordingly, interim arrangements were planned in the respective Regional Standing Committee meetings for evacuation of power from the generation projects.

Reply of the management is to be viewed against the following facts;

- Even considering the time gap of two to three years given by the generators against the required time of three to four years for setting up a transmission system, the interim arrangements made by PGCIL for 21 months to 56 months cannot be justified. Further as per the Guidelines (April 2006) of Ministry of Power, CTU has the key responsibility of network planning and development based on NEP and not based on the LTA applications.

- Although it is correct that interim arrangements were agreed in the Standing Power Committee because scheduled commissioning of some of the generation projects was ahead of scheduled commissioning date of associate transmissions systems, actual implementation of generation projects was delayed. If the associated transmission systems are commissioned as per their own scheduled time frame, connectivity through interim arrangement could be avoided.

Thus, due to delay in completion of transmission lines, PGCIL was forced to evacuate power through interim arrangement against the directions given in the NEP which, as per POSOCO, resulted in congestion in Chhattisgarh and adjoining areas.

In the Exit Conference, Ministry agreed (January 2020) with the audit observation that delay should be an exception and not the rule.

3.2.3 Planning for evacuation of Renewable Energy

Forum of Regulators (FORs), a body of CERC Power Regulators, entrusted (5 October 2011) a detailed study for "Preparing a plan for transmission infrastructure development for likely capacity addition of Renewable Energy (RE) based power plants in the States rich in RE potential" to PGCIL.

PGCIL, along with State transmission utilities, conducted studies and prepared a Green Energy Corridor (GEC) Report which was submitted (September 2012) to Ministry of New and Renewable Energy. As per above report, a total of 17,683 MW RE capacity addition was envisaged by the end of 31 March 2017 in Rajasthan and Gujarat (potential States) out of which 5,212 MW was assessed surplus available for evacuation through ISTS after considering renewable purchase obligation (RPO) between 7-15 *per cent* for the host States and balance available for interstate transmission. For evacuation of the surplus 5,212 MW RE power after intra State consumption by host states, PGCIL proposed 765 kV transmission corridor from Bhuj Pooling Station in Gujarat (WR) to Moga in Punjab (NR). Subsequently, CEA re-assessed (17 June 2013) RE capacity for Rajasthan and Gujarat to 10,423 MW. However, surplus available power after considering RPO of the host states was not re-assessed in the changed scenario.

Audit observed that against the planned RE capacity of 10,423 MW, 6,928[19] MW was commissioned in Gujarat and Rajasthan during the period 2012-17. However, transmission corridor planned for evacuation of RE power was not commissioned upto 31 March 2017. Only the part of the corridor from Bhuj-Ajmer was actually commissioned in stages from December 2017 to March 2019.

Management/ Ministry stated (January/ June 2019) that till 31 March 2017, no envisaged RE generation materialised for interconnection at GEC-Inter-state network. It was also stated that most of the RE generation had come up in Intra state only for host state consumption. Accordingly, GEC–ISTS scheme commissioning was rescheduled.

The reply itself indicates deficiencies in the planning because despite commissioning of 66.47[20] *per cent* of planned RE generation capacity in Rajasthan and Gujarat, no RE power was available for Inter-State transfer. It indicates that there was deficiency in the assessment of internal consumption of RE power in host States and also in the assessment of existing margin available in transmission system at the time of planning the system.

In the Exit Conference with Ministry, Audit requested (January 2020) Management to provide details of RE power evacuated from these corridors along with updated status of commissioning of the corridor. While the Ministry provided (May 2020) the details of RE capacity connected to ISTS, the details of power evacuated from these corridors were not provided which would have facilitated the assessment of adequacy and utilisation of the system.

However, Audit obtained the data of actual power flows from this line from POSOCO, which indicated that the average power flows in different sections of this corridor ranged between 2.93 to 6.79 *per cent* only and peak power flows never exceeded 30.65 *per cent*.

Thus, Green Energy Corridor transmission system planned for evacuation of RE power through Inter-State transmission network was not used effectively for its envisaged purpose due to deficiencies in the assessment of requirements.

3.2.4 Insufficient focus on up-gradation of existing lines in planning process

While discussing the challenges in the implementation of 11th Plan, NEP 2012 stated that the main challenges faced by implementing agencies in completion of transmission works included delay in forest clearance, problems of right of way

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[19] ***Addition during period 2012-17 by, Gujarat:3,065 MW and Rajasthan: 3863MW***

[20] ***Addition of RE generating capacity in Gujarat and Rajasthan during 12th Plan i.e. 6,928 MW against the envisaged RE generating capacity addition of 10,423 MW***

and challenges in acquiring land for substations. NEP, therefore, emphasised the need to optimise the transmission corridors by considering the possibility of increasing the transmission capacity of existing lines through use of re-conductoring and other measures in the planning stage itself.

Audit observed that in the absence of network plan, PGCIL had not prepared any separate plan for upgradation of the existing system. The planned projects of the NEP (162 projects) all pertained to new projects. Further, as PGCIL does not have system to assess the need for upgradation before laying new line, this data is not captured in their records. In the Exit Conference, CMD/ PGCIL admitted that efforts made to maximise utilisation of existing system before evolving new system may not be recorded. During audit examination also, it was noted that, DPRs of 18 projects selected for audit did not indicate any studies having been conducted to explore the possibility of up-gradation of existing transmission lines before planning new lines as suggested by NEP 2012. Therefore, structured system of considering the possibility of upgradation of existing lines and considering re-optimisation of the system was not available. During 2012-17, while PGCIL commissioned 233 new lines, upgradation was carried out to only eight lines.

Inadequate focus on upgradation of existing lines was also evident from the following instances:

(i) In compliance of CERC directions, a Committee comprising of CTU, CEA and POSOCO studied the maximum loadability limits for transmission lines and communicated to PGCIL (12 January 2013) various measures[21] to improve line loadability[22] of 222 lines of 400 kV and above. However, PGCIL took action to improve the loadability of only 10 lines by making line reactors switchable.

(ii) Again, during their fourth meeting (January 2015) of the Committee on congestion in transmission, constituted by CERC, POSOCO reiterated the measures communicated in January 2013 and inter-alia added that there was need for re-conductoring of 12 out of 17 lines involved in 1,341.01 circuit km in four regions to mitigate congestion in long term.

All the lines identified by the Committee for reconductoring/ upgradation had critical importance in the meshed grid e.g. robustness of Meerut - Muzaffarnagar line and Muzaffarnagar - Roorkee lines has a crucial role in meeting power requirements of large industrial and agricultural load centres of West UP and to facilitate transfer of hydro power from THDC to West UP. Similarly, Farakka - Malda line has an important role to meet power requirements of the North Bengal and Sikkim hills during the period of low hydro generation in the hills. Singraul - Anpara line- is important because it was a link between the two large generating

[21] ***Providing line-in-line-out load centres at intermediate points in respect of 98 lines, conversion of line reactors as bus reactors in respect of 222 lines, etc.***

[22] ***Loadability of a transmission line in power system is limited by thermal limit, surge impedance limit and stability limit etc.***

regions. Therefore, non-upgradation of these lines has consequences related to sub-optimal utilization of the system.

The recommendations (January 2015) of the Committee for upgradation of lines remained largely unattended. Resultantly, transmission constraints continued to be observed by POSOCO even as late as October 2019 in the Northern Region and Southern Region due to high loading in five of these lines viz., 400 kV Singrauli – Anpara S/c line, 400 kV Anpara and Obra line, 400 kV Mohindergarh - Bhiwani line, 400 kV Hiriyur - Neelmangala line and 400 kV Dadri – G. Noida S/c, 400 kV line. Thus, absence of adequate measures to upgrade the lines as suggested by CERC committees/ POSOCO ultimately resulted in transmission constraints.

Studies, for example, an international report[23] (June 2013), on 'Integrated Transmission Planning and Regulation', have demonstrated that the latent transmission capacity can be released to network users through application of advanced network, information and communication technologies on existing transmission network, thereby postponing or even eliminating the need of asset heavy network reinforcement.

In this regard, Audit further observed that re-conductoring of existing Farakka – Malda 400 kV D/C transmission line by PGCIL resulted in increase in the total transfer capacity of ER-NER corridor from 900 MW to 1,400 MW and that of ER-NR from 3,780 MW to 3,900 MW. Thus, inadequate focus on re-conductoring deprived PGCIL of the possibility to enhance the transfer capacity of the Inter-regional corridors and effectively optimize the utilisation of existing transmission network, as repeatedly impressed upon by various committees and NEP.

In the Exit Conference, Ministry stated (January 2020) that out of these 17 lines, eight lines in NR were discussed in the Standing Committee meeting (February 2016) for proposed re-conductoring. In the meeting, POSOCO admitted that all of these lines except 400 kV Singrauli - Anpara S/c and 400 kV Anpara - Obra were overloaded in the past but after commissioning of other new parallel circuits, these lines were operating at normal load and hence did not require re-conductoring. Further, two lines in ER viz. Farakka - Malda line and Maithon - Maithon RB 400 kV D/c line were discussed in the said meeting and approved for re-conductoring. However, remaining seven lines in three Regions (i.e, WR, SR and ER) were not deliberated upon for re-conductoring in any meeting of Standing Committee and therefore, no action for re-conductoring of these seven lines was taken.

Reply of Ministry is to be viewed against the facts:

(i) The issue was discussed during the 8th meeting of Co-ordination Forum held in April 2019 wherein Chairperson, CERC stated that re-conductoring option was cheaper as compared to construction of new line and suggested that some regulatory mechanism needs to be put in place to encourage putting up new conductors for increasing the capacity of existing transmission line

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[23] ***Electricity Policy Research Group, University of Cambridge, London***

(ii) Efforts made to examine utilization of the existing network capacity to the extent possible using various technologies have not been recorded.

(iii) The reply is silent on the specific action taken against the recommendation of the Committee to upgrade the remaining seven lines. Moreover, PGCIL had preferred laying new parallel transmission lines in place of option to upgrade existing transmission lines as suggested by the committee.

3.2.5 No plan for augmentation of transfer capacity in long term

Two parameters viz. Transmission capacity and Transfer capacity are relevant for assessing the capability of Inter-Regional (IR) corridor. Transmission capacity of IR corridor is the sum of the ratings of transmission links joining two regions. IR Transfer capability, on the other hand, is a holistic measure of the ability of the IR corridor along with interconnected ISTS links to transfer power from one region to another.

As per NEP 2012, the transmission capacity being summation of capacities of inter-regional links is a figurative representation of the bonds between the regions. These aggregate numbers do not indicate actual power transfer capability across different regions/ states. Thus, transmission capacity has a limited role in indicating capability of corridors to handle power flows.

As per clause 16.1 of 'Procedure for making application for grant of medium term open access to inter-state transmission system' approved by CERC, PGCIL has to notify Total Transfer Capability [24](TTC) for four years on the 31st day of March each year. Further, the sub-committee of the Central Advisory Committee (CAC) of CERC constituted to examine transmission congestion related issues recommended (June 2015) that in view of the necessity for transparency in declaration of TTC/ ATC in planning horizon, the results of long term studies carried out by CTU should be made available on their website.

Audit, however, observed that PGCIL fixed targets and prepared plans only for the transmission capacity to be augmented over a period but no targets were fixed or declaration made for achieving the transfer capability in long term.

Non-declaration of TTC on long term horizon was highlighted in the CAG Audit Report No.18 of 2014. COPU, in their 20th Report (2017-18), also emphasised that PGCIL should declare TTC targets as per CERC regulations because without such long-term planning it was not possible to grant long-term access and medium-term open access to Inter-State transmission systems. In their reply to COPU, Ministry stated that PGCIL had engaged an international consultant for advising on TTC and related issues.

Audit observed that at present, TTC declaration appears on the PGCIL website till the month of January 2020, however, no long-term declaration has been done by PGCIL. In the absence of the declaration of TTC for four years as per the

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[24] ***Total Transfer capacity means the amount of electric power that can be transferred reliably over the transmission system under a given set of operating conditions***

regulatory requirements, there was no benchmark to assess the actual performance of PGCIL in terms of its capability to transfer power. Moreover, there was no practice of declaring the targets for intra-regional transfer capability *viz.* between ISTS and State Transmission Systems (STU system). One of the crucial information that ISTS was expected to provide to the States as power drawing entities was how much power (in MW) they would be able to draw through ISTS in future in order to meet their load demand. This would help in planning for procurement of power through ISTS i.e. from outside the State. For this, ISTS capability to bring power up to the State boundary and capability of the STU system to draw that power is required to be assessed. This is the crux of coordinated planning for which the Act mandates that CTU would coordinate with all required agencies. This vital deliverable was found missing.

Ministry stated (June 2019) that as per the recommendation of the international consultant, the TTC/ ATC is to be declared by the operator i.e. POSOCO and System Operating Limit (SOL)[25] is to be declared by CTU. It has been decided that the guideline/ methodology for calculation of SOL would be submitted by CTU.

In the Exit Conference with Ministry, representative of CEA stated (January 2020) that action plan on the recommendation of the international consultant will be finalized by June 2020.

The reply is to be viewed against the fact that it is essential to monitor and declare TTC in the long run as per requirements of extant CERC Regulations since 2009 which has not been done so far.

3.2.6 Status of augmentation of Inter-Regional Transfer capability

Audit analysed the status of actual augmentation of Transfer Capability *vis-a-vis* transmission capacity during 2012-17 as given in Table 3.3.

Table 3.3

Corridor	Transmission Capacity (at the end of 12th Plan)	TTC as per CTU (April 2017)	% age of TTC to transmission capacity
(In MW)			
ER-NER	2,860	1,400	48.95
ER-NR	21,030	4,200	19.97
ER-WR	12,790	-	-
ER-SR	7,830	3,460	44.19
NER-NR	3,000	-	-
WR-NR	15,420	12,900	83.66
WR-SR	12,120	4,940	40.76
Total	**75,050**		

[25] *SOL is defined as the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a transmission system configuration to ensure operation within acceptable reliability criteria*

Audit observed that at the end of 12th five-year plan, the TTC of different corridors ranged between 19.97 *per cent* and 83.66 *per cent* of their respective transmission capacity. It was further observed that for every pair of double circuit AC line[26], IR transmission capacity considered achievable by CEA in the NEP 2012 is less than 50 *per cent* of its transmission capacity. For example, gross thermal rated capacity for double circuit 400kV quad bundled ACSR moose[27] conductors is of the order of 3,957 MW[28] but the IR capacity target for the same in NEP as per CEA is only 1,600MW. This implies that NEP targets are already less than 50 *per cent* of thermal rated capacity of the individual links and CTU should endeavor to achieve at least the same. The actual TTC achieved in all the regions except WR-NR was less than even 50 *per cent* of the achievable targets. Thus, the actual achievement of CTU indicates significant scope for improvement through diligent optimization.

Audit further analysed the corridor-wise addition to TTC achieved by PGCIL *vis-à-vis* addition in the transmission capacity in the 12th Plan and observed as given in Table 3.4.

Table 3.4

Corridor	Transmission capacity (at the end of 11th Plan)	TTC[29] (March 2012)	% age of TTC to transmission capacity 11th Plan	Transmission capacity (at the end of 12th Plan)	TTC as per CTU (March 2017)	%age of TTC to transmission capacity
ER-NER	1,260	570	45.24	2,860	1,400	48.95
ER-NR	12,130	3,100	25.56	21,030	4,200	19.97
ER-WR	4,390	1,000	22.78	12,790	-	-
ER-SR	3,630	830	22.87	7,830	3,460	44.19
NER-NR	-	-	-	3,000	-	-
WR-NR	4,220	2,200	52.13	15,420	12,900	83.66
WR-SR	1,520	1,000	65.79	12,120	4,940	40.76
Total	**27,150**			**75,050**		

It may be seen from the above that:

(i) Even though significant transmission capacity had been added in XII Plan in ER-NR (8,400 MW) and WR-SR (10,600 MW) corridors, TTC in terms of percentage to transmission capacity actually decreased from 25.56 to 19.97 *per cent* in ER-NR corridor and from 65.79 to 40.76 *per cent* in WR-SR corridor.

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26 ***Transmission lines which carry three phase power are usually configured as either single circuit or double circuit. A single circuit configuration has three conductors for the three phases. While a double circuit configuration has six conductors (three phases for each circuit)***

27 ***Aluminium conductor steel reinforced of 500 sq mm diameter***

28 ***√3X400kVX0.714kAmp=3957MW at 50 deg C ambient temperature, final temperature 85 deg Solar radiations = 1045 Watt/m2. Wind Speed = 2 km/hour Absorption Coefficient = 0.8 Emissivity Coefficient = 0.45 and Age > 1 year***

29 ***AS per NLDC because CTU did not have practice of declaring TTC at that time***

(ii) Although significant transmission capacity was added in ER-WR (8,400 MW) and NER-NR (3,000MW) corridors, TTC was not worked for these corridors.

Ministry stated (July 2019/ May 2020) TTC is dynamic in nature and is dependent on network topology of ISTS as well as Intra - State Transmission System including Load –Generation scenario and weakest link in the corridor etc. Further management added that aggregate transmission capacity which is a static value between two areas may differ vastly from TTC which is dynamic in nature.

Reply of the management is to be viewed against the fact that:

(i) Audit has compared the TTC declared by CTU one year in advance i.e. TTC 'as planned' for future which at the time of its declaration cannot be affected by day to day real time dynamic factors. On the other hand, TTC as declared regularly by POSOCO at a point of time may be affected by dynamic factors such as load generation balance etc. which is not the subject matter of the audit observation. Further, internationally also some norms to assess adequacy of inter-regional transfer capacity with reference to operating requirement had been fixed. Like the European Council as per their Ten year Transmission Network development Plan 2012, had proposed a criterion for interconnection development, asking Member states a minimum import capacity level equivalent to 10 *per cent* of their installed production. In United Kingdom and USA the planning and evaluation of the transmission network is carried out in terms of transfer capacity.

(ii) During the 8th meeting of the Co-ordination Forum convened by CEA in April 2019 for smooth and coordinated development of power system in the country, Joint Chief (Engg.) of CERC stated that CTU grants LTA to applicants 34 years hence and grants LTA to such applicants on "existing system" or "with system strengthening". While granting such LTA it uses the numbers of ATC of three to four hence to decide the need of system strengthening. Therefore, it must declare these numbers for market participants to bring transparency. Moreover, declaration of such ATC with clear indications of the assumptions and possibility of updating thereof based on the changing conditions would facilitate the market rather than misleading it.

3.2.7 Reduced margins for Short and Medium Term Open Access

Access to transmission system is given to users through Long Term Access (LTA) or Medium Term Open Access (MTOA) or Short Term Open Access (STOA). As per National Electricity Policy 2006, network expansion should be planned and implemented keeping in view the anticipated transmission needs that would be incident on the system in the open access regime. Prior agreement with the beneficiaries would not be a pre-condition for network expansion.

The above requires a robust transmission system to cater to the requirements of all categories of customers. Audit observed that while the requirements for long term access were taken care of by dedicated planning of transmission system, the access to short and medium-term customers was provided from the margins available within the system. Non-achievement of adequate power transfer capability as per the projections in the NEP (highlighted in the preceding paragraph) reduced the availability of margins thereby impacting short term power transactions as brought out subsequently.

A Committee formed by CERC in December 2015 to review the transmission planning, connectivity, Long Term Access, Medium Term Open Access and other related issues observed in their report (September 2016) that margins for short term and medium-term customers were inadequate.

Based on the information provided by POSOCO, Audit also observed that due to inadequate margins available in the transmission system for short term open access, there were rejections of STOA requests by POSOCO for purchase for power from different regions. The details of requests for STOA rejected in different regions[30]are given in Table-3.5.

Table 3.5

(In MW)

Year	NRLDC*	SRLDC	NERLDC	WRLDC	ERLDC
2012-13	21,86,265.66	0	561.8	17,652.76	1,263
2013-14	31,27,936.41	17,340.04	423	1,413.44	18,783.23
2014-15	71,72,611.02	0	576.57	2,240.65	4,243.16
2015-16	64,59,258.32	0	0	169.05	167.55
2016-17	1,75,69,275.81	3,275.55	0	610.05	407.39

It is provided by POSOCO in MWhr.

Thus, sufficient margins were not available for short term transactions in line with the spirit of the Electricity Act and National Electricity Policy.

Ministry stated (June 2019) that

(i) As per CERC Open Access in inter-state transmission Regulation 2008, for STOA, the short term customers shall be eligible for access to the surplus capacity available on the inter-state transmission system after use by the long term customer and medium term customers by virtue of (a) inherent design margin (b) margin available due to variation in power flow and (c) margin available due to inbuilt spare transmission capacity created to cater to future load growth or generation addition. Hence, ISTS system is planned to take care of power transfer requirement under long term.

(ii) As per Report of CERC on Short Term Open Access, the volume of electricity transacted through power exchange that could not be cleared as percentage to unconstrained cleared volume was reduced from 17 *per cent* in 2012-13 to 0.5 *per cent* in 2017-18 by implementing additional inter regional links by PGCIL.

[30] ***Northern Region Load Despatch center (NRLDC), Southern Region Load Despatch Centre (SRLDC), North Eastern Region Despatch Centre (NERLDC), Western Region Load Despatch Centre (WRLDC) and Eastern Region Load Despatch Centre (ERLDC)***

The reply is to be viewed against the facts that;

(i) National Electricity Policy, 2005 requires transmission network expansion to be planned and implemented keeping in view the anticipated needs that would be incident on the system in the open access regime. It also adds that prior agreement with the beneficiaries would not be a pre-condition for network expansion. Moreover, CERC regulations do not prevent PGCIL from taking up system strengthening schemes in the absence of LTA for which separate regulatory approval can be obtained from CERC. In fact, in addition to LTA driven schemes, many system strengthening schemes are regularly approved in the SCPSP.

(ii) As per Monthly report of CERC on Short Term Transactions of Electricity in India (March 2019), volume of electricity that could not be cleared in Indian Energy Exchange due to congestion was 3.44 *per cent* of the unconstrained cleared volume. Also in terms of time, congestion occurred is 35.62 *per cent*[31] during March 2019. Further as per data furnished by POSOCO, during the year 2017-18, 3,06,156 MWhr/ 11,597 MW of short term applications were rejected due to non-availability of margins in NR and SR region respectively.

In the Exit Conference, Ministry stated (January 2020) that system should have the capacity to accommodate all types of open access and for that regulation can be modified.

Therefore, existing planning process needs to be reviewed in view of present Regulations and Open Access Policy.

3.2.8 Need for planning to address regional power transfer requirements

Non-availability of adequate margins for short term transactions as discussed above was also visible in congestion and variations in the electricity prices over regions. The Country is divided into 13 bid areas (IEX) for power exchange transactions. In case there is no congestion, single price prevails across all bid areas called Market Clearing Price. Otherwise in case of congestion across a transmission corridor, the net power of upstream areas will not flow to downstream deficit areas resulting in variation in prices in different bid areas. The prices prevailing in different bid areas in such case are called Area Clearing prices. A comparison of Market Clearing Price[32] with Area Clearing price[33] in Indian Energy Exchange (IEX) is given in Table 3.6.

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[31] ***Percentage of time congestion occurred during the month (Number of hours congestion occurred/total number of hours in the month)***

[32] ***MCP is the clearing price for cleared transactions in the whole country, if there is no congestion at all***

[33] ***The country is divided into 13 bid areas (IEX) for power exchange transactions. The criteria for defining these areas is the location of the physical constraints in the structure of transmission network, including national and/or control area border. In case of congestion across a transmission corridor, the net sale of upstream areas will not flow to downstream deficit areas. The cleared prices in all areas i.e., Area Clearing Prices (ACPs) are adjusted so that the flow of power across transmission corridor is same as available transfer capability***

Table 3.6
Comparison of Market Clearing Price and Area Clearing price in IEX

Year	MCP (₹ per kWhr	Area clearing prices in bid areas (₹ per kWhr)												
		A1	A2	E1	E2	N1	N2	N3	S1	S2	S3	W1	W2	W3
2012-13	3.49	3.26	3.26	2.91	2.1	3.13	3.13	3.13	**6.86**	**7.29**	-	3.07	3.07	2.80
2013-14	2.80	2.44	2.44	2.42	2.42	2.55	2.55	3.10	**4.73**	**5.57**	-	2.52	2.52	2.25
2014-15	3.51	4	3.24	3.22	3.22	3.23	3.23	3.27	**5.11**	**5.93**	-	3.07	3.07	3.05
2015-16	2.73	2.47	2.47	2.47	2.47	2.77	2.77	2.79	**3.79**	**4.28**		2.46	2.46	2.46
2016-17	2.41	2.29	2.29	2.29	2.29	2.58	2.58	2.61	**2.79**	**2.79**	**2.92**	2.29	2.29	2.29

Source: Data obtained from the website of Indian Energy Exchange

It is evident from Table 3.6 that there has been a reduction in Market Clearing Price of electricity traded through power exchange but the Area Clearing Prices in bid areas in Southern Region continued to be higher than Market Clearing Price on an average annually.

Economic Survey 2015-16 stated that on 29 December 2015, no congestion was observed in the electricity grid and a single price was discovered in the IEX.

Audit observed that though formation of National Grid was completed in December 2013, single price (₹2.30/ kWh) was discovered on 29 December 2015 in the power exchange (IEX) in short term transactions, *i.e.,* almost after two years. Thereafter, only on 23 days (from the period 29 December 2015 to 31 March 2017) single price was discovered on the power exchange, IEX. During the intervening period (2013-15) there were wide variations in the prices prevailing in the different regions and regional inequalities in power prices still persist as the Area Clearing Price ranged between ₹2.29 per kWhr to ₹2.92 per KWhr even in 2016-17.

Thus, there is still a need to improve the inter-regional power transfer capability to reduce congestion and to ensure smooth flow of power and remove regional inequalities in power prices.

Ministry stated (June 2019) that with continuous expansion and growth in transmission capacity upon implementation of new transmission schemes based on anticipated power transfer requirement, the percentage time blocks congested has improved from 21.8 *per cent* during Q1 of 2017-18 to 0.6 during Q1 of 2018-19 and from 8.8 *per cent* during Q2 of 2017-18 to 0.5 *per cent* during Q2 of 2018-19 for southern region. Management further added that One Nation – One Grid – One Price was also achieved for all 76 days in Q2 of 2018-19.

In the Exit Conference, Ministry stated (January 2020) that One Nation One Grid and One price has since been achieved.

Reply of the management is to be viewed against the fact that on an average annual basis, Area Clearing Price of electricity traded through power exchange in Southern Region (S1, S2 and S3) continued to be higher than the Market Clearing

Price from the period 2012-13 to 2018-19. Further, One Nation – One Grid - One price was achieved only on 57 days and 25 days in Q3 and Q4 of 2018-19, respectively. Thus, variations in the prices prevailing in the different regions and regional inequalities in power prices continue to persist.

Also COPU, in its 20th Report (2017-18) on Planning and Implementation of Transmission Projects by PGCIL and Grid Management by POSOCO, had stated that by commissioning of a number of transmission elements at ISTS level and effective project management by PGCIL, corridor capacity will increase progressively which in turn would pave the way for single price of power across the country. Electricity trade results in optimisation of resources, creates competition and increases the possibility and options for supplying cheaper and regular power to consumers. Benefitting the consumers through competitive electricity trade is enshrined in the preamble of the Electricity Act. Therefore, existing planning process needs to be reviewed with focus on maximising power transfer capability of the power system with the mandated aim of achieving overall economy and efficiency in the power sector.

3.3 Investment approval of projects

Records relating to planning of 18 selected transmission projects taken up for implementation during April 2012 to March 2017 with the status of augmentation to transmission network made by PGCIL upto March 2017 were examined in audit. Results of examination are as under:

3.3.1 Non-adherence to stipulated timelines for preparing detailed project reports

As per provisions contained in Works & Procurement Policy and Procedure (WPPP) of PGCIL, a time limit of eight weeks has been prescribed for approval of DPR by CMD after in-principle clearance from CEA.

In 14 out of 18 selected projects, there was delay ranging from three weeks to 165 weeks beyond the stipulated eight weeks' time in WPPP for obtaining internal clearance of DPR from CMD after approval of the projects in the respective Standing Committee Meetings. Thus, the time limit was not adhered to by PGCIL for preparation and approval of DPR by CMD as prescribed in the WPPP.

Such delay on the part of PGCIL to fulfil its own obligations has a cascading effect on the overall completion and commissioning of various projects as evident from the fact that out of 18 selected projects, only two projects were completed within the scheduled time upto December 2018 and 13 projects were completed with delays ranging from 4 to 71 months. The remaining three projects are to be completed with anticipated delays ranging from 6 to 109 months. Thus, it becomes imperative that all efforts should be made to strictly adhere to various internal timelines.

Ministry stated (June 2019) that delay in approval of the DPRs has no material impact in commissioning of the schemes as the initial delay is taken care of during implementation phase of the projects. The conclusion that delays in implementation arise out of cascading effect of DPR approval is not a true representation analysis of the situation.

Reply needs to be viewed against the fact that out of 18 selected projects only two projects were completed within stipulated time period. This shows that delay in approval of DPR is also one of the factors of delay in commissioning of the transmission projects.