the next five (5) years starting from 1st April of the next year and submit the same to the STU by 31st July every year.

(a) For carrying out the demand estimation, the distribution licenses shall use trend method, time series, econometric methods or any state-of-the-art methods and shall include daily load curve (hourly basis) for a typical day of each month. The daily load curve (hourly basis) for a typical day of a month shall be provided in such a way as to depict the clear picture of demand pattern in the control area.

(b) In the Planning Code, STU has been assigned the responsibility to estimate overall demand of the State in co-ordination with all the distribution licensees based on demand estimate. The STU shall estimate by 31th August every year, the demand for the entire State duly considering the diversity for the next five (5) years starting from 1st April of the next year. The STU shall also capture the diversity in demand for all aspects in its demand estimatimation for the State.

(c) To ensure consistency and uniformity in approach across states towards demand estimation, it has been provided that Forum of Regulators (FOR) may develop guidelines for demand estimation considering the factors such as economic parameters, historical data and sensitivity and probability analysis.

3.8. Generation Resource Adequacy Planning

(a) After load is forecasted, the next step is to assess the existing resources based on their capability to contribute to meet the peak demand. This exercise would give an indication about the additional resources that must be procured to meet the forecasted demand.

(b) However, while deciding on the resource procurement plan, it is important not only to factor in the resource gap (between demand and the existing resource capability) but also to ensure availability of adequate reserves for meeting contingencies. For this, there is a need for computing the Planning Reserve Margin (PRM) based on the factors like Loss of Load Probability (LOLP), Energy Not Served (ENS) etc.

(c) Planning Code of the draft Grid Code, therefore, provides that each distribution licensee shall do the assessment of the existing generation resources with due regard to its capacity contribution to meet the peak demand. Further, based on the demand estimate and assessment of the existing generation resources, the distribution licensee shall prepare generation resource procurement plan which shall specify the procurement from resources under State control area and regional control area. Generation resource procurement planning shall be done for different time horizons, namely long -term, medium term and short term as per GNA provisions to ensure:

(d) adequacy of generation resources and

(e) planning reserve margin (PRM) taking into account loss of load probability and energy not served as specified by CEA.

(f) Considering the prevailing thrust on Renewable Energy (RE) generation and steps towards reduction of carbon emission from Power Sector, Generation planning should be done in a way to maximize the harnessing of available RE resources and its economical transmission/dispatch to the load centers. The other factors like available Distributed Energy Resources (DER), RE generation pattern and subsequent requirement of Energy Storage System (ESS), load variations (including sessional load variations) shall also be factored in while planning for optimal harnessing of RE resources.

(g) Distribution licensee shall also factor-in the Renewable Purchase Obligation (RPO) target including Hydro purchase Obligation (HPO), as applicable, in their generation resource adequacy planning and in subsequent generation procurement plan.

(h) Each distribution licensee is expected to carry out these exercises involving demand estimation, existing generation resource assessment, determination of PRM before designing its resource procurement planning. However, empirical evidence shows that if each distribution licensee engages in resource procurement planning only based on its own sets of data (on load forecasting, generation resource assessment and PRM) in isolation, it would lead to sub-optimal planning at the national level leading to excess capacity creation.

(i) As such, it is important that some national level agency carries out a simulation by compiling the data on each of the aforesaid parameters (viz. State /Discom-wise load forecasting, existing resource assessment, PRM etc.) and factor in seasonal load variation across States, share of each State in the national co-incident peak, feasibility of sharing of capacities amongst States etc. Such an exercise can lead to optimal resource adequacy allocation among different States.

(j) The draft Grid Code has sought to entrust this responsibility to NLDC at the national level. This Planning Code specifically mentions that STU on behalf of distribution licensees in the State shall provide to NLDC by 30th September every year, the details regarding demand forecasting, assessment of existing generation resources and such other details as may be required for carrying out a national level simulation for generation resource adequacy for States.

(k) To assist the State in drawing optimal generation resource adequacy plan, NLDC shall carry out a simulation by 31st October every year based on the information received from STU and in consideration with the information related to demand estimation, generation planning and related matters as available with CEA.

(l) However, as the Commission believes in a bottoms-up approach, it has been provided that even after the NLDC has done a national simulation and indicated resource procurement planning for States, it would be desirable for the States to do due diligence at their level. This will ensure that each distribution licensee remains commercially responsible for its own resource procurement strategy which it has to finalize after seeking approval of the concerned SERC.

(m) Distribution licensees shall have the responsibility to demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year based on their demand forecasting and the generation resource procurement planning.

(n) The draft Grid Code also highlights the need for proper enforcement of resource adequacy framework developed based on the above principles and accordingly has provided that non-compliance of the resource adequacy target determined as above would make the distribution licensees liable for payment of resource adequacy non-compliance charge as may be determined by the appropriate Commission.

(o) To maintain uniformity and to optimize the State generation resource adequacy, it has been provided that FOR may develop a model Regulation stipulating inter alia the methodology for generation resource adequacy assessment, generation resource procurement planning and compliance of resource adequacy target by the distribution licensees.

3.9. Transmission resource adequacy assessment

(a) As per Section 38 (2) of the Electricity Act 2003, the CTU is responsible for development of an efficient, co-ordinated and economical ISTS system and discharge all functions related to planning and coordination. The Commission notes that such planning should include the assessment of power transfer capability across flow gate, import and export capability across control areas and regions as well transnational exchange of power to ensure that no power gets bottled up on account of requirement of augmentation of transmission system. Further, assessment of such capabilities shall also ensure that the transmission system is being planned optimally.

(b) The CTU shall coordinate with various stakeholders such as CEA, MNRE, state renewable development agencies, STUs, distribution licensee, SLDC, RLDC, NLDC and generation developers to make a comprehensive assessment of inter-state transmission plan covering power evacuation schemes, pooling stations, enhancement of power transfer capability between regions and enhancement of power transfer capability for each STU system.

(c) In addition to the inter-State transmission planning, the CTU shall plan from time to time, system strengthening schemes, need of which may arise to overcome the constraints in power transfer and to improve the overall performance of the grid. The inter-State transmission proposals including system strengthening scheme identified on the basis of the planning studies would be discussed, reviewed and finalized in the meetings of Transmission Planning, in consultation with identified Entities as notified by Government of India from time to time.

(d) Similarly, at state level, STU is responsible for development of an efficient, coordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centres and discharge of all functions related to planning and coordination.

(e) The Transmission planning criterion shall be based on the security philosophy on which the ISTS has been planned. The security philosophy may be as per the Transmission Planning Criteria and other guidelines as specified by CEA from time to time.

(f) CTU shall also factor in the Reactive Power requirement into the Grid as part of inter-State Transmission planning which includes planning studies for Reactive Power compensation of ISTS including reactive power compensation requirement at the generator's /bulk consumer's switchyard and for connectivity of new generator/ bulk consumer to the ISTS in accordance with GNA Regulations.

4. Connection Code

4.1. The Connection Code deals with the technical criteria for connectivity, procedure for connectivity and technical requirements for safe and secured physical connection and integration of either new or modified grid elements, The Indian Power System is one of the largest Grid in the world having interconnection with its neighboring countries. The purpose of this Code is to ensure the safety, stability, integrity and reliability of the Grid while connecting/ integrating new or modified grid elements into the Grid.

4.2. With the penetration of large RE capacity into the Grid there is a need to revamp the Connection Code. The main factors for such a change are as follows:

(a) The current Connection Code needs to be reviewed in light of the newly introduced Connectivity and GNA under the GNA Regulations.

(b) Provisions are required to be incorporated to identify any threat to grid security on introduction of a new or modified power system element including smooth integration of RE.

4.3. The proposed Connection Code comprises of the following sections:

(a) Compliance with existing rules and regulations

(b) Procedure for Connection

(c) Connectivity Agreement

(d) Technical Requirements

(e) Data and Communication Facilities

The key changes are elaborated in subsequent paragraphs.

4.4. Compliance with existing Rules and Regulations

The prevailing Connection Code provides that any user connected or seeking connection to ISTS shall comply with Central Electricity Authority (Technical Standards for connectivity to the Grid) Regulations, 2007 and Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-state Transmission and related matters) Regulations,2009. In the post-GNA regime, the Connectivity Regulations, 2009 shall be repealed and shall be succeeded by the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-StateTransmission System) Regulations, 2022 (GNA Regulations). The Commission observes that the multiple regulations have been notified by various statutory bodies and accordingly all users connected or seeking connection to the grid shall comply with the applicable regulations as specified in the Draft IEGC.

4.5. Provision for Grant of Connectivity

(a) As per the existing regulatory regime, the process for Grant of Connectivity to ISTS is governed by 2009 Connectivity Regulations. Under the GNA Regulations, the grant of Connectivity to the ISTS shall be as per the GNA regulations.

(b) Commission observes that when any new or modified element is integrated into grid there is a need for such an entity to submit technical data for the purpose of studies. POSOCO has already included first time charging Procedure as a part of its Operating Procedure since June 2020. It is clarified that connection of an element after shutdown or tripping shall not be treated as “modified element” and shall not be required to go through first time charging procedure. However, in case the element has been modified, such as a transformer of 300 MVA replaced by 500 MVA, it would be required to go through first time charging procedure.

(c) The Expert Group recommended to include the first time charging procedure as a part of Grid Code. Accordingly, it has been proposed that NLDC shall prepare a detailed procedure covering modalities for first time energization and integration of new or modified power system element. It is important that similar procedure is also developed by SLDC for connection of new or modified element to the grid. Accordingly, it has been proposed that SLDC shall prepare a detailed procedure covering modalities for first time energization and integration of new or modified power system element for intra-state transmission system. The State grids being part of the National grid, are inter-connected and the said detailed procedures would facilitate smooth and integrated grid operation of Indian power system. The Commission has further proposed that in the absence of procedure of concerned SLDC, the NLDC procedure shall be applicable for the elements of 220 kV and above (132 kV and above in case of North Eastern Region).

(d) Users, after completing the all prerequisite requirements as per the prevailing provisions and necessary site tests will approach the concerned RLDC or SLDC, as the case may be, in the NLDC specified format to get the permission for first energization.

4.6. Connectivity Agreement

As per the existing regulatory regime, a Connection agreement is signed by the applicant in accordance with the 2009 Connectivity Regulations. Under the GNA Regulations, the Connectivity agreement shall be signed which shall include all technical details also. However, since transmission licensee does not apply separately for Connectivity, the Connectivity Agreement with such transmission licensee integrating a new element has not been covered under the GNA regulations which was covered under the 2009 Connectivity Regulations. Further, such Connectivity Agreement with transmission licensee under the 2009 connectivity regulations was purely for technical purpose where transmission licensee submitted necessary technical details. Accordingly, it has been proposed that the Connectivity Agreement with transmission licensee shall be signed under the Grid Code. CTU shall specify the formats of submission of technical data by the Transmission licensee and draft Connectivity Agreement to be signed with the transmission licensee.

4.7. Technical Requirements

(a) The Commission feels that connection of a new element to the power system must ensure security of the grid as well as of the element getting connected to the grid as per the CEA Connectivity Standards. It is, therefore, essential to analyze the impact of the element on the power system when the element is transitioning from construction to operation phase. Accordingly, the Commission has proposed that NLDC or RLDC, in consultation with CTU shall carry out a joint system study six (6) months before the expected date of first energization of a new power system element to identify operational constraints. Further, all associated technical data shall be submitted to the CTU and NLDC or RLDC for necessary technical studies to enable CTU/NLDC to accurately forecast the results.

(b) Proposed Connection Code further specifies that SLDC shall also do the similar exercise in consultation with STU for the intra-state system, and specifically for elements of 220 kV and above (132 kV and above in case of North Eastern region) which shall facilitate the SLDCs to identify the operational constraints in their intra-state network and their rectification in a timely manner which shall facilitate smooth and integrated grid operation of Indian power system

4.8. Data and Communication Facilities

(a) For seamless data exchange, safe and secure integration as well as monitoring/supervision of the operation of the grid elements, establishment of reliable speech and data communication systems shall have to be in place. To connect Grid elements into the Grid, users need to comply with the CERC (Communication System for Inter-State Transmission of Electricity) Regulations, 2017 and the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020. The Commission has proposed the requirement of established Data and Communication facilities in Connection Codes.

(b) In view of large integration of RE and fast dynamic changes in the power system network, visibility of data at various control centers are of growing importance day by day. Data exchange is must for supervision and control of the grid by the System Operators so as to achieve overall secured and integrated operation of the grid.

5. Protection Code

5.1 The protection system plays a pivotal role in ensuring stability of the power system which isolates the faulty section of the power system from the rest of the electrical network and thereby preventing system collapse during disturbances and reducing outage time. The importance of reliable and correct operation of protection system has been brought out in various orders of the commission and reports of various committees from time to time. One of the learning from the 2012 Grid disturbance is requirement of robust protection audit system.

5.2 The failure of protection system may result in incidents of tripping(s), which may further cause cascade tripping of various elements, depletion of network and loss of generation or load in some cases and even partial or complete blackout of the grid. The CEA Grid Standards Regulations provide the classification for events of multiple trippings wherein grid events have been classified into Grid Disturbances and Grid Incidents depending upon the severity and impact of generation/load loss in a region. RLDC releases a list of Grid Events of its region on monthly basis on its website and also submit to the respective RPC and the same is discussed in Protection Sub-committee meetings at RPC level for remedial measures and further actions.

5.3 The Expert Group has observed as follows:

"(1) Protection Code

(a) This code has been newly added to have a common protection philosophy amongst users of the grid, to provide proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended operation of protection system, to have a repository of protection system and settings at regional level, to have a repository of events, timelines for submission of data and ensure healthiness of recording equipment's along with time synchronization, to provide for periodic audit of protection system.

(b) It is observed that in absence of a coordinated procedure and specific guidelines of protection systems the desired outcomes are not being witnessed. It is therefore recommended that a coordinated protection setting are adopted by all users of regional grid. The provision of protection philosophy to be adopted at regional level has been added to achieve a uniformity in the procedure for adopting protection settings. The guideline and recommendation provided under various committee Report as constituted under the various orders (Report of the Task Force on Power System Analysis under Contingencies (2013), TASK II PHASE I AND PHASE II – FINAL REPORT (2017), CBIP Manual on Power System Protection (Publication No. 328), Protection philosophy of different RPC (Regional Power Committee)/ NPC

(National Power Committee) and any other as prescribed by commission) may form the basis for finalising the protection philosophy by all RPCs uniformly.

(c) The Protection Code covers the following aspects:
i. Protection philosophy
ii. Protection Settings
iii. Protection Audit Plan
iv. System Protection Schemes (SPS)
v. Recording Instruments"

5.4 Based on the above recommendations, the Commission has proposed inclusion of a new Protection Code in the Draft Grid Code with the following sections:

(a) Protection Protocol
(b) Protection Settings
(c) Protection Audit Plan
(d) System Protection Scheme
(e) Recording Instruments

5.5 **Protection Protocol**

(a) The Commission has proposed that the users connected to the integrated grid shall be guided by uniform protection protocol. The protection protocol shall be evolved by RPC ensuring a common and coordinated approach. In doing this, RPC may be guided by the principal that electrical protection function for equipment connected with the grid shall be provided as per the CEA Technical Standards. However, users may have electrical protection functions over and above or better than the ones specified as per CEA Technical Standards. We observe that each RPC has issued protection philosophy for respective region on its website. Such philosophy at ERPC website dated 2.9.2016 is as under:

PROTECTION PHILOSOPHY OF EASTERN REGION

In the Special meetings of PCC held on 30.12.2014, 10.04.2015 & 20.07.2015 the Protection Philosophy for Eastern Region was agreed as given below:

Sl. No.	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
1	Zone-1	Forward	80%	Instantaneous (0)	As per CEA
2a	Zone-2	Forward	For single ckt- 120 % of the protected line	0.5 to 0.6 - if Z2 reach overreaches the 50% of the shortest line ; 0.35- otherwise	As per CEA
			For double ckt- 150 % of the protected line		As per CEA
2b	Zone-2 (for 220 kV and below voltage Transmission lines of utilities)	Forward	120 % of the protected line, or 100% of the protected line + 50% of the adjacent shortest line	0.35	As per CEA with minor changes
3	Zone-3	Forward	120 % of the (Protected line + Next longest line)	0.8 - 1.0	As per CEA
4	Zone-4	Reverse	10%- for long lines (for line length of 100 km and above) 20%- for shot lines (for line length of less than 100 km)	0.5	As per CEA

Note:

1) ***Zone-2:- Z2 Reach should not encroach the next lower voltage level.***
2) ***Zone-3:- If Z3 reach encroaches in next voltage level (after considering "in-feed"), then Z3 time must be coordinated with the fault clearing time of remote end transformer.***
3) ***Zone-4:- If utility uses carrier blocking scheme, then the Z4 reach may be increased as per the requirement. It should cover the LBB of local bus bar and should be coordinated with Z2 time of the all other lines.***
4) ***The above settings are recommended primarily (exclusively) for uncompensated lines.***

(b) The Draft Grid Code envisages uniform protection protocol. However, each RPC shall develop the protection protocol for the region. The RPCs may coordinate among themselves to ensure uniform protection protocol as far as possible duly considering region specific variations, if any. Further, the protection protocol may vary as per the operational experience and necessary modification/revision as per requirement shall be carried out after approval of the concerned RPC.

5.6 Protection Settings

(a) It is observed that multiple agencies are involved for implementation of protection settings such as a line is owned by a transmission licensee and the substation terminating bays of that line may have different owner and hence coordination is required among them for successful implementation and real time operation of the protection system as per the required settings. Accordingly, to evolve a common and coordinated approach, the Commission has proposed that the relay settings shall be discussed and decided at RPC level. To achieve this, a centralized database of relay settings shall be required which will be coordinated with the remote end settings. This data base of settings containing information of various relays has been proposed to be created, updated and verified during the relay audit. The data base shall be maintained with the Regional Power Committees with different levels of access of different users.

(b) The protection group of each entity shall be required to furnish the protection system implemented to the respective RPC in a prescribed format and also obtain approval of the concerned RPC in case of revision in protection setting and implementation of new protection system within specified timeline.

5.7 Protection Audit Plan

(a) Periodic audit of the protection system shall be ensured by the user. The audit shall broadly cover the important aspects of protection system, namely the setting and scheme adopted in line with agreed protection philosophy of RPC, the deviations from the RPC protection philosophy, the healthiness of Fault Clearing System etc. It is suggested that each user shall conduct internal audit of their protection system annually and any shortcomings identified shall be rectified and informed to RPC. In order to ensure healthiness of protection system for better grid operation with due weightage for checks and balances in the system, all users shall also conduct third party protection audit of each sub-station (132 kV and above in NER and 220 kV and above for rest of the grid) once in five years or earlier as advised by RPC.

(b) In order to ensure reliability of protection system, certain indices for protection devices and switching devices have been included in the draft Grid Code. The proposed indices have already been notified through the Central Electricity Regulatory Commission (Standards of Performance of inter-State transmission licensees) Regulations, 2012 wherein the inter-state transmission licensees shall furnish prescribed data to enable POSOCO compute the Indices. One such sample submitted by SRLDC for June 2022 is as under:

Annexure-1

PERFORMANCE INDICES CALCULATION AS PER CERC SOP REGULATION FOR June 2022

SN	Name of Transmission Licencee	Nc	Nf	Nu	Ni=Nf+Nu	D= (Nc/Nc+Nf)	S= (Nc/Nc+Nu)	R= (Nc/Nc+Ni)	(1/S)+(1/D)	(1/R)+1
1	KTL	0	0	0	0	Nil	Nil	Nil	Nil	Nil
2	MTL	0	0	0	0	Nil	Nil	Nil	Nil	Nil
3	RSTCL	2	0	0	0	1.000	1.000	1.000	2.000	2.000
4	PGCIL SR-1 (incl.PVTL & PSITSL)	11	0	1	1	1.000	0.917	0.917	2.091	2.091
5	PGCIL SR-2 (incl.PNMTL)	17	0	1	1	1.000	0.944	0.944	2.059	2.059
	NET SR ISTS	30	0	2	2	1.000	0.938	0.938	2.067	2.067

Abbreviations :
Nc :- Number of correct operations
Nf :- Number of failures to operate at internal power system faults
Ni =(Nf+Nu):- Number of incorrect operation & sum of Nu+Nf
Nu :- Number of unwanted operation
D :- Dependability Index.
S :- Secuirty Index.
R :- Reliability Index.

(c) In order to ensure better reliability and security of the protection system, the Commission is of the view that these protection performance indices namely Dependability Index, Security Index and Reliability Index shall be submitted by all users to the respective RPCs on a monthly basis.