Central Electricity Regulatory Commission
New Delhi

Coram:

Shri Jishnu Barua, Chairperson
Shri Arun Goyal, Member

File No. L-1/265/2022/CERC **Date:02.08.2024**

STATEMENT OF REASONS

In the matter of

Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023

1. Introduction:

1.1. The Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 was notified on 28.04.2010 (hereinafter referred to as "2010 Grid Code"), and subsequently, six amendments have been made in the 2010 Grid Code.

1.2. In view of the developments in the power sector over the years, for the updation of the existing Regulations, the Commission, vide notification dated 07.06.2022, issued the Draft CERC (Indian Electricity Grid Code) Regulations, 2022 (hereinafter referred to as the "Draft Grid Code") seeking comments/ suggestions/ observations from the stakeholders/public. Explanatory Memorandum for Draft CERC (Indian Electricity Grid Code) Regulations, 2022 were uploaded on 09.10.2022.

1.3. Written Comments were received from 75 stakeholders, including Discoms, Generators, Transmission Licensees, Statutory bodies, Power Exchanges, Individuals and Associations. A list of stakeholders who submitted written comments is attached as **Appendix-I**. Subsequently, the Public Hearing on the Draft Grid Code was conducted on 19.10.2022 through video conferencing, wherein 21 stakeholders made their presentations/ oral submissions. A list of stakeholders who made their submissions during the public hearing is attached as **Appendix II**. The detailed comments and presentations made during the Public hearing are available on the website of the Commission at www.cercind.gov.in.

1.4. After due consideration of the comments/ suggestions/ objections received and views of the participants in the Public Hearing, the Commission has finalized the

Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023 (hereinafter referred to as '2023 Grid Code') which was notified on 29.05.2023 and made effective from 1.10.2023.

1.5. The CERC (Indian Electricity Grid Code) Regulations, 2023 ('2023 Grid Code' or 'Grid Code') comprise 10 Chapters and 7 Annexures and include various provisions regarding the roles, functions and responsibilities of the concerned statutory bodies, generating companies, licensees and any other person connected with the operation of the power systems within the statutory frameworks envisaged in the Act and the Rules and Notifications issued by the Central Government, COD, security of grid, reserves, scheduling, connecting new elements requirements, compensation for low load operation etc. Three new chapters viz Protection Code, Cyber Security Code, and Monitoring & Compliance Code have been introduced in the 2023 Grid Code. The Planning Code has been renamed as Resource Planning Code. The main provisions which have been newly introduced under the different codes of the 2023 Grid Code are as follows:

a) Resource Planning Code:

Provisions for integrated resource planning, including demand forecasting, generation resource adequacy planning, and transmission resource adequacy assessment, required for secure grid operation have been introduced under the newly introduced Resource Planning Code.

b) Protection Code:

The chapter covers the protection protocol, protection settings and protection audit plan of electrical systems.

c) Commissioning and Commercial Operation Code:

The provisions related to the trial run and declaration of commercial operation of wind, solar, hybrid, pumped storage, and ESS stations have been introduced. Further, the necessary provisions regarding data to be furnished prior to the trial run and the documents and test reports required to be furnished before the declaration of Commercial Operation by Generating entity/ Transmission System have also been incorporated.

d) Operating Code:

(i) The framework for reserves comprising primary, secondary, and tertiary reserves has been introduced. States are obligated to ensure the availability of the quantum of secondary and tertiary reserves within their control area as published by NLDC. In case of a shortfall, NLDC shall procure the reserves on behalf of the state with cost liability to the erring state.

(ii) The provisions for carrying out periodic tests, on power system elements to ascertain the correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system have been incorporated.

(iii) The provisions regarding reactive power compensation have been introduced for generating stations also in addition to drawee entities at 5 paise/kVARh with an escalation of 0.5paise/kVArh per year.

(iv) Compensation for black start service has been introduced as actual injection @ 110 % of the normal rate of charges.

e) <u>Scheduling and Despatch Code:</u>

(i) The scheduling procedure has been modified to align with the GNA Regulations.

(ii) The mechanism for Security Constrained Unit Commitment (SCUC) and Security Constraint Economic Despatch (SCED) has been included.

(iii) Provisions and methodology for the supply of power from alternate sources in case of USD and Forced outage and the flexibility to the generating station other than REGS for replacing its scheduled generation with power supplied from REGS have been introduced.

f) <u>Cyber Security Code and Monitoring and Compliance Code:</u>

(i) Cyber Security Code deals with measures to be taken to safeguard the national grid from spyware, malware, cyber-attacks, network hacking, procedures for security audits from time to time, system upgradation requirements, etc.

(ii) Monitoring and Compliance Code deals with the monitoring of compliances to the Grid Code by the various entities in the grid by RLDCs, RPCs, or any other person.

1.6. The proposed Regulations and reasons for the Commission's decisions are given in the succeeding paragraphs. While an attempt has been made to consider all the comments/suggestions received, the names of all the stakeholders may not appear in the deliberations.

CHAPTER 1 – PRELIMINARY

2. Preliminary (Regulation 2 (1))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation 2 (1) of the Draft Regulations:

"(1) These regulations shall apply to: all users, State Load Despatch Centres, Regional Load Despatch Centres, National Load Despatch Centre, Central Transmission Utility, State Transmission Utilities, licensees, Regional Power Committees and Power Exchanges to the extent applicable."

2.2. **Comments have been received from New Age Markets in Electricity and PCKL**

2.2.1. **New Age Markets in Electricity** has suggested adding "OTC platform" in the clause.

2.2.2. **PCKL** has suggested adding “REMC” in the clause.

2.3. **Analysis and Decision**

2.3.1. Considering suggestions of PCKL, ‘REMC’ has been added to the Regulations. Further, Regional Power Committees, Settlement Nodal Agencies, Qualified Coordinating Agencies and Power Exchanges, to the extent applicable, have also been inserted in the Regulations.

2.3.2. ‘OTC’ Platform has not been considered since its roles and responsibilities are not included in the Grid Code.

3. Definitions (Regulation 3 (1)(2))

3.1. **Commission’s Proposal**

3.1.1. The Commission had proposed the following in Regulation 3(1) (2) of the Draft Regulations:

“2. ‘Alert State’ means the state in which the system is within the operational parameters as defined in this Code but a contingency has occurred;”

3.2. **Comments have been received from Tata Power and POSOCO**

3.2.1. **TATA Power** has requested clarification in this clause, as operational parameters are not clearly defined in the proposed code. The allowable band of frequency is mentioned as 49.95 - 50.05 Hz in clause 30.2. So, whether the Grid Code refers to Frequency as the only operational parameter. Please clarify.

3.2.2. **POSOCO** has suggested that a Power system shall be categorized as an in alert state when the power system is operating with operational parameters within their respective operational limits, but an N-1 contingency leads to a violation of security criteria. The power system remains intact under such an alert state.

3.3. **Analysis and Decision**

3.3.1. The term ‘operational parameters’ has been defined in the Grid Code under Regulation 3(1) as the parameters for system security as specified by the system operator, including frequency, voltage at station-bus, angular separation, damping ratio, short circuit level, and inertia.

3.3.2. Suggestions of POSOCO have been accepted, and accordingly, the definition of Alert State in Regulation 3 (1) of the 2023 Grid Code Regulations has been specified as,

“2. ‘Alert State’ means the state in which the operational parameters of the power system are within their respective operational limits, but a single n-1 contingency leads to violation of system security;”

4. Power Grid has suggested adding a new clause in (Regulation 3 (1))

4.1. **Power Grid** has suggested inserting an additional definition in Regulation 3 (1) of the Draft Regulations,

“Associated Transmission System or ATS shall have the same meaning as defined in CERC (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022.”

4.2. **Analysis and Decision**

4.2.1. Keeping in view suggestions of Power Grid, the definition of ATS has been inserted in Regulation 3 (1) of the 2023 Grid Code Regulations,

“Associated Transmission System’ or ‘ATS’ shall have the same meaning as defined in the GNA Regulations;”

5. New Clause proposed for addition in (Regulation 3(1))

5.1. **Greenko Group, Hero Future Energy, Tata Power, Statkraft, National Solar Federation and Enel** have suggested an additional insertion,

“Auxiliary Energy Consumption means in relation to a period in case of a generating station / ESS means the quantum of energy consumed by auxiliary equipment of the generating station / ESS, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station / ESS and the transformer losses within the generating station / ESS, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station;

Provided that Auxiliary Energy Consumption, in case of ESS, shall not include cycle loss occurred during charging and discharging of ESS.

Provided that auxiliary energy consumption shall not include energy consumed for supply of power to housing colony and other facilities at the generating station and the power consumed for construction works at the generating station and integrated coal mine.”

5.2. **Analysis and Decision**

5.2.1. The Commission has inserted the definition of Auxiliary Energy Consumption in the Regulation 3 (1) of the 2023 Grid Code Regulations,

“‘Auxiliary Energy Consumption’ shall have the same meaning as defined in the Tariff Regulations;”

6. Definition (Regulation 3 (1) (10))

6.1. **Commission’s Proposal**

6.1.1. The Commission had proposed the following in Regulation 3(1) (10) of the Draft Regulations:

“10. ‘Bilateral Transaction’ means a transaction for exchange of energy or power (MW or MWh) between a specified buyer and a specified seller, directly or through a trading licensee or discovered in the Term Ahead Market at power exchange through anonymous bidding, and scheduled from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for any time period;”

6.2. **Comments have been received from New Age Market in Electricity, PXIL and PCKL**

6.2.1. **New Age Market in Electricity** has suggested adding OTC market in the definition.

6.2.2. **PXIL** has requested that the definition of ‘bilateral transaction’ as provided in GNA

Regulations 2022 be retained.

6.2.3. **PCKL** has suggested including transactions through the DEEP Portal in the definition.

6.3. **Analysis and Decision**

6.3.1. The definition has been aligned with definition provided in the GNA Regulations.

6.3.2. Suggestions to include ‘OTC market’ is not accepted since no specific provisions have been included in Grid Code related to ‘OTC market ‘. Similarly, a transaction through DEEP portal is already included in the definition under a transaction between a specified buyer and a specified seller.

6.3.3. The Commission has modified the definition of Bilateral Transaction in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"‘Bilateral Transaction’ means a transaction, other than collective transaction, for exchange of power between a specified buyer and a specified seller directly or through a trading licensee or at a Power Exchange;"

7. Definition (Regulation 3 (1) (15))

7.1. **Commission’s Proposal**

7.1.1. The Commission had proposed the following in Regulation 3 (1) (15) of the Draft Regulations:

"15. ‘Captive Generating Plant’ means a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such cooperative society or association;"

7.2. **Comments have been received from BALCO and IWPA**

7.2.1. **BALCO** has suggested an additional in the clause:

"‘Captive User’ shall mean the end user of the electricity generated in a Captive Generating Plant and the term "Captive Use" shall be construed accordingly. As defined in rule 3(2) of Electricity Rules 2005."

7.2.2. **IWPA** has commented that a new definition is not required and suggested to consider the definition of the Electricity Act 2003

7.3. **Analysis and Decision**

7.3.1. Considering the suggestions received, the Commission has modified the definition of Captive Generating Plant in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"‘Captive Generating Plant’ shall have the same meaning as defined in the Act;"

8. Definition (Regulation 3 (1) (32))

8.1. **Commission’s Proposal**

8.1.1. The Commission had proposed the following in Regulation 3 (1) (32) of the Draft Regulations:

"32. ‘Demand’ means the demand of active power in MW;"

8.2. **Comments have been received from Shri Anshuman and KSEBL**

8.2.1. **Sh. Anshuman and KSEBL** has suggested including reactive power in the definition.

8.3. **Analysis and Decision**

8.3.1. Considering the suggestions, the Commission has modified the definition of Demand in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Demand' means the demand of active power in MW and reactive power in MVAr;"

9. Definition (Regulation 3 (1) (34))

9.1. **Commission's Proposal**

9.1.1. The Commission had proposed the following in Regulation 3 (1) (34) of the Draft Regulations:

"34. 'Despatch Schedule' means the ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time;"

9.2. **Comments have been received from SRPC**

9.2.1. **SRPC** has suggested replacing the word "exported" with "injected", as for the generating station, generally injection schedule is used and not exported.

SRPC has also suggested modifying the clause as follows, "… to the Grid in a time block and from time to time;"

9.3. **Analysis and Decision**

9.3.1. Considering the suggestions, the Commission has modified the definition of Despatch Schedule in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Despatch Schedule' means the ex-power plant net MW and MWh output of a generating station, for a time block, scheduled to be injected to the Grid from time to time;"

10. Definition (Regulation 3 (1) (40))

10.1. **Commission's Proposal**

10.1.1. The Commission had proposed the following in Regulation 3 (1) (40) of the Draft Regulations:

"40. 'Emergency State' means the state in which one or more variables are outside their operating limit or many of the equipment are operating above their respective loading limit;"

10.2. **Comments have been received from POSOCO**

10.2.1. **POSOCO** has suggested amending the definition as below:

"Power system shall be categorized under emergency state when the power system is operating with operational parameters outside their respective operational limits or equipment are above their respective loading limits."

10.3. **Analysis and Decision**

10.3.1. Considering the suggestions of POSOCO, the Commission has modified the definition of Emergency State in Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Emergency State' means the state in which one or more operational parameters are outside their operating limit or many of the equipment connected to the grid are operating above their respective loading limit;"

11. Definition (Regulation 3 (1) (56))

11.1. **Commission's Proposal**

11.1.1. The Commission had proposed the following in Regulation 3 (1) (56) of the Draft Regulations:

"56 'Generating Unit' means

a) for all generating stations except solar photo voltaic, wind and hybrid stations, an electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator;

b) for solar photo voltaic generating stations including hybrid, each inverter along with associated modules shall be reckoned as a separate generating unit;

c) for wind generating stations including hybrid: each wind turbine generator with associated equipment shall be reckoned as a separate generating unit;"

11.2. **Comments have been received from SRPC, SECI, IWPA, Wartsila and PCKL:**

11.2.1. **SRPC** has suggested including ESS in the definition.

11.2.2. **SECI** suggested the following amendment under sub-clause (b)

"(b) for solar photo voltaic *generating* stations including hybrid, each inverter along with associated photovoltaic Modules and other equipment shall be reckoned as a separate generating unit;"

11.2.3. **IWPA** suggested the following amendment under sub-clause (c):

"(c) In old WEGs, multiple WEGs are connected to a single service connection with no metering for individual WEGs. Hence, this may please be modified suitably taking into account the old / existing wind turbines."

11.2.4. **Wartsila** has suggested that the Engine Generator also needs to be considered along with the Turbo-Generator.

11.2.5. **PCKL** has suggested including waste to energy power stations in the exception list of generating stations.

11.3. **Analysis and Decision**

11.3.1. The suggestions of SECI have been accepted and accordingly the Commission has modified the definition of Generating Unit in Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Generating Unit' means

a) an unit of a generating station (other than those covered in sub-clauses (b) and (c) of this clause) having electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator;

b) an inverter along with associated photovoltaic modules and other equipment in respect of generating station based on solar photo voltaic technology;

c) a wind turbine generator with associated equipment, in respect of generating station based on wind energy;

d) in respect of RHGS, combination of hydro generator under sub-clause (a); or solar generator under sub-clause (b) or wind generator under sub-clause (c) of this clause;"

12. Definition (Regulation 3 (1) (60))

12.1. **Commission's Proposal**

12.1.1. The Commission had proposed the following in Regulation 3 (1) (60) of the Draft Regulations:

"60. Grid-forming capability means the capability of a Power Generating Module to generate its own voltage waveform without relying on the grid voltage to synchronize and run as a black-start resource."

12.2. **Comments have been received from Hitachi Energy**

12.2.1. **Hitachi Energy** has suggested a modification in the clause:

"means the capability of a Power Generating Module to generate its own voltage waveform without relying on the grid voltage to synchronize and <u>counteract immediately to the changes in *the* grid voltage (voltage steps, phase jumps, faults etc) and to emulate the behaviour of voltage source behind the impedance</u>"

12.3. **Analysis and Decision**

12.3.1. The definition of Grid forming capability has been deleted.

13. Definition (Regulation 3 (1) (63))

13.1. **Commission's Proposal**

13.1.1. The Commission had proposed the following in Regulation 3 (1) (63) of the Draft Regulations:

"63. 'Hot Start' in relation to steam turbine, means the start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values);"

13.2. **Comments have been received from NTPC**

13.2.1. **NTPC** has suggested modifying the clause as per the CEA Regulation of Construction of Power Plant.

13.3. **Analysis and Decision**

13.3.1. The Commission has noted the suggestion and acknowledges that the definition of 'Hot Start' is identical to the definition provided in the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations of 2010 and 2022. The relevant excerpts from these regulations are as follows:

Regulation 2(1)(q) of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010:

“(q) "Hot Start", in relation to steam turbine, means start up after a shut down period of less than 10 hours (turbine metal temperatures approximately 80% of their full load values);”

Regulation 2(1)(t) of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022:

“(t) “Hot start”, in relation to steam turbine, means start up after a shut down period of less than ten hours (turbine metal temperatures approximately eighty percent of their full load values);”

13.3.2. In view of the above discussion, the definition as proposed in the Draft Regulation has been retained.

14. The new clause in draft regulation 3(1) provided as under:

14.1. **New Proposals**

14.1.1. **SECI** has suggested new definitions to be inserted in the Regulation:

“Intermediary Procurer: means any entity that procures power from single / multiple generation stations and sells to single / multiple buyers. The intermediary procurer shall also be a beneficiary as defined in SI. No. 9”

14.1.2. **POSOCO** has suggested new definitions to be inserted in the Regulation:

“Near miss event” means an incident of multiple failures that had the potential to cause a grid disturbance, power failure or partial collapse but did not result in a grid disturbance;

“Operational Parameters” means for the purpose of these regulations frequency, voltage at station-bus, angular separation, damping ratio, short circuit level, inertia or any other parameter specified by system operator

“Resilience” means the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event

14.2. **Analysis and Decision**

14.2.1. The Commission has inserted the definitions of Intermediary Procurer, Near miss event, Operational Parameters, and Resilience in Regulation 3 (1) of the 2023 Grid Code Regulations,

“Intermediary Procurer shall have the same meaning as defined in Electricity (Amendment) Rules, 2022.

“‘Near Miss Event’ means an incident of multiple failures that has the potential to cause a grid disturbance, power failure or partial collapse but does not result in a grid disturbance;”

"'Operational Parameters' means the parameters for system security as specified by the system operator including frequency, voltage at station-bus, angular separation, damping ratio, short circuit level, inertia;"

"'Resilience' means the ability to withstand and reduce the magnitude or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, or rapidly recover from such an event;"

15. Definition (Regulation 3 (1) (72))

15.1. **Commission's Proposal**

15.1.1. The Commission had proposed the following in Regulation 3 (1) (72) of the Draft Regulations:

72. 'Minimum Turndown Level' means minimum station loading corresponding to the units on bar upto which a regional entity generating stations is required to be on bar on account of less schedule by its buyers or as per the direction of RLDC as detailed in Chapter 7 of this Code;

15.2. **Comments have been received from SRPC**

15.2.1. **SRPC** has commented that the Minimum Turn Down Level should be at least what is specified by Central Electricity Authority (Flexible operation of thermal power plants) Regulations, 2022.

15.3. **Analysis and Decision**

15.3.1. Considering the suggestions of SRPC, the Commission has modified the definition of Minimum Turndown Level in Regulation 3 (1) of the 2023 Grid Code Regulations, as under:

"'Minimum Turndown Level' means the minimum output power expressed in percentage of maximum continuous power rating that the generating unit can sustain continuously; to be on bar and includes minimum power level as defined in CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023"

16. Definition (Regulation 3 (1) (76))

16.1. **Commission's Proposal**

16.1.1. The Commission had proposed the following in Regulation 3 (1) (76) of the Draft Regulations:

76. 'Normal State' means the state in which the system is within the operational parameters as defined in these regulations.

16.2. **Comments have been received from POSOCO**

16.2.1. **POSOCO** has suggested amending the definition as below:

"Power system shall be categorized under normal state when the power system is operating with operational parameters within their respective operational limits and equipment are within their respective loading limits."

16.3. **Analysis and Decision**

16.3.1. The Commission has modified the definition of Normal State in the Regulation 3 (1) of the 2023 Grid Code Regulations:

"'Normal State' means the state in which the operational parameters of the power system are within their respective operational limits and equipments are within their respective loading limits;"

17. Definition (Regulation 3 (1) (83))

17.1. **Commission's Proposal**

17.1.1. The Commission had proposed the following in Regulation 3 (1) (83) of the Draft Regulations:

"83. 'Primary Reserve' means the maximum quantum of power which will immediately come into service through governor action of the generator in the event of sudden change in frequency. This reserve response shall start instantaneously and attain its peak in less than 30 seconds, and shall sustain upto 5 minutes;"

17.2. **Comments have been received from SRPC and Wartsila**

17.2.1. **SRPC** has suggested amending the definition as below:

"'Primary Reserve' means the maximum quantum of power which will immediately come into service through governor action <u>or through any other resource</u> of the generator in the event …"

SRPC commented that, in line with Ancillary Services Regulations, 2022 as Primary Reserve can be maintained on demand side also.

17.2.2. **Wartsila** has requested for a clarification on "Instantaneously" and to specify time period.

17.3. **Analysis and Decision**

17.3.1. Considering the suggestions, the Commission has modified the definition of Primary Reserve in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Primary Reserve' means the maximum quantum of power which will immediately come into service through governor action of the generator <u>or frequency controller or through any other resource</u> in the event of sudden change in frequency as specified in clause (10) of Regulation 30 of these regulations;"

18. Definition (Regulation 3 (1) (92))

18.1. **Commission's Proposal**

18.1.1. The Commission had proposed the following in Regulation 3 (1) (92) of the Draft Regulations:

"92. 'Reference contingency' means the maximum positive power deviation occurring instantaneously between generation and demand and considered for estimation of reserves;"

18.2. **Comments have been received from SRPC**

18.2.1. **SRPC** has suggested considering negative power deviation in the definition.

18.3. **Analysis and Decision**

18.3.1. The reference contingency is to be estimated by the system operator under Annexure-2 of the Grid Code and includes both conditions of generation outage and demand outage. Accordingly, no change is proposed in the definition.

19. Definition (Regulation 3 (1) (97))

19.1. **Commission's Proposal**

19.1.1. The Commission had proposed the following in Regulation 3 (1) (97) of the Draft Regulations:

"97. 'Regional Transmission Account' or 'RTA' means accounts of transmission issued by the RPC Secretariat for the purpose of billing and settlement of transmission charges of ISTS in the concerned region;"

19.2. **Comments have been received from SRPC**

19.2.1. **SRPC** has suggested modifying the definition to be in line with Sharing Regulations.

19.3. **Analysis and Decision**

19.3.1. The Commission has modified the definition of Regional Transmission Account in Regulation 3 (1) of the 2023 Grid Code Regulations:

"'Regional Transmission Account' or 'RTA' means accounts of transmission issued by the RPC for the purpose of billing and settlement of transmission charges of ISTS in the concerned region in accordance with the Sharing Regulations;"

20. Definition (Regulation 3 (1) (102))

20.1. **Commission's Proposal**

20.1.1. The Commission had proposed the following in Regulation 3 (1) (102) of the Draft Regulations:

"102. 'Secondary Reserve' means the maximum quantum of power which can be activated through Automatic Generation Control (AGC) to free the capacity engaged by the primary control. This reserve response shall come into service starting from 30 seconds and shall sustain up to 15 minutes;"

20.2. **Comments have been received from NHPC, SRPC and AP Transco**

20.2.1. **NHPC** has suggested aligning the definition with that as per the Regulation 7(1)(e) of CERC (Ancillary Services) Regulations 2022.

20.2.2. **SRPC** has suggested removing "to free the capacity engaged by the primary control". SRPC has also commented that even if there is no frequency correction there may be tie-line correction as per ACE formula.

20.2.3. **AP Transco** has commented that up to 15 minutes of sustaining time may not be sufficient to replace secondary reserves with tertiary reserves, hence this may be increased.

20.3. **Analysis and Decision**

20.3.1. Keeping in view the suggestions, the definition has been aligned with the definition provided in the Ancillary Services Regulations.

20.3.2. The Commission has modified the definition of Secondary Reserve in the Regulation 3 (1) of the 2023 Grid Code Regulations,

"'Secondary Reserve' means the maximum quantum of power which can be activated through secondary control signal by which injection or drawal or consumption of an SRAS provider is adjusted in accordance with Ancillary Service Regulations;"

CHAPTER-2 - RESOURCE PLANNING CODE

1. General (Regulation 4 (2))

1.1. Commission's Proposal

1.1.1. The Commission had proposed the following in Regulation 4 (2) of the Draft Regulations:

"(2) The planning of generation and transmission resources shall be for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix with a focus on integration of environmentally benign technologies after taking into account the need, inter alia, for flexible resources, storage systems for energy shift and demand response measures for managing the intermittency and variability of renewable energy sources."

1.2. Comments have been received from POSOCO, LBN Lab

1.2.1. **POSOCO** has commented that CEA has issued draft guidelines for the Resource Adequacy framework for Indian electricity sector. Guidelines must be followed by institutions and stakeholders. Reliability standards to be defined separately or referred to the final version of guidelines.

1.2.2. **LBN LAB** has suggested defining the 'optimum generation mix' so that the least-cost portfolio can be determined at the national and state level, and can be integrated into the 'generation resource procurement plan'. Additionally, FOR could consider laying down guidelines for all-source procurement.

1.3. Analysis and Decision

1.3.1. With regard to suggestions of POSOCO regarding CEA Guidelines, we note that the Central Government has issued a resource adequacy framework under Rule 16 of the Electricity (Amendment) Rules, 2022 on 29.12.2022 as follows:

> ***"16. Resource Adequacy**. — (1) A guideline for assessment of resource adequacy during the generation planning stage (one year or beyond) as well as during the operational planning stage (up to one year) shall be issued by the Central Government in consultation with the Authority, within six months from the date of commencement of these rules.*
>
> *(2) The State Commission shall frame regulations on resource adequacy, in accordance with the guidelines issued by the Central Government and the model Regulations framed by Forum of Regulators, if any, the distribution licensees shall formulate the resource adequacy plan in accordance with these Regulations and seek approval of the Commission.*
>
> *(3) The State Commission shall review the resource adequacy, for each of the distribution licensees, as per the time line given in resource adequacy guidelines issued by the Central Government.*
>
> *(4) The State Commission may determine non-compliance charges for failure to comply with the resource adequacy target approved by the Commission.*

(5) The National Load Dispatch Centre and the Regional Load Dispatch Centres shall carry out assessments of resource adequacy, for operational planning, at the national and regional levels, respectively, on an annual basis, in accordance with the guidelines issued by the Central Government.

(6) The State Load Despatch Centre shall carry out assessments of resource adequacy, for operational planning, at the state level, in consultation with all the concerned stakeholders on an annual basis, in accordance with the guidelines issued by the Central Government and the directions of the State Commission.

(7) The State Load Despatch Centre shall review the operational resource adequacy on a daily, monthly and quarterly basis.

1.3.2. Considering the above, the provisions regarding resource adequacy have been included in the 2023 Grid Code. The Resource Planning Code provides regulatory framework to facilitate Resource adequacy framework with Integrated Resource planning ensures optimal harnessing of available resources in economical and sustainable manner and is essential for secure grid operation with high reliability, high resilience and more flexibility.

1.3.3. Regarding suggestions to include Reliability Standards, the same are beyond the scope of present Regulations and may be considered after following pre-publication.

1.3.4. In order to bring uniformity in approach and optimality in generation resource adequacy in the State, the Forum of Regulators (FOR) has been requested to develop Model Regulations.

1.3.5. The provision as proposed in the Draft Regulations has been retained.

2. INTEGRATED RESOURCE PLANNING (Regulation 5 (2) (i))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation **5 (2) (i)** of the Draft Regulations:

"(2) Demand Forecasting:

(i) Each distribution licensee within a State shall estimate the demand in its control area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, for 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. The demand estimation shall be done using 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."

2.2. **Comments have been received from POSOCO, HPSEBL, RE Connect Energy, Torrent Power, Tata Power, BALCO, Sterlite, MSEDCL, Statkraft, MPPMCL and PCKL**

2.2.1. **POSOCO** has commented that Demand forecasting by Distribution Licensees should include the impact of new loads such as EVs and electric cooking etc. Deemed licenses, bulk consumers, and CPPs should also be mandated to submit demand estimates.

2.2.2. **HPSEBL** has commented that for Demand Forecasting, a common software should be deployed by respective RPCs at the Regional Level to have a uniform procedure for the same.

2.2.3. **RE Connect Energy** has requested that demand forecasting be made mandatory for grid operators at the national and regional level as well as STU and distribution licensees. All STU and distribution licensees should be asked to mandatorily submit the projections for the 5-year period by the due date(s). A penalty mechanism depending on the system size of the utility/STU/licensee should also be formulated so that the activity remains relevant.

2.2.4. **Torrent Power Limited** has commented that the entire exercise of seeking details of Demand Forecasting is duplication. Therefore, the requirement of such a provision may be reviewed.

2.2.5. **Tata Power** has commented that considering so many variables involved in the Demand forecast, like open access consumers, distributed generation, demand response etc., it's not practically possible to provide demand forecasting for the next 5 years on an hourly basis with desired accuracy. Accordingly, Tata Power has suggested the following to be incorporated:

(i) Need to have a provision allowing revision of demand estimates for better accuracy
(ii) Demand forecasting to be done on a fortnightly instead of hourly basis
(iii) Uniform demand forecasting methodology across Discoms.

2.2.6. **Balco and Sterlite** have commented that it will be difficult for the Discom to predict the demand of an open access consumer and the same may be as provided by an open access consumer.

2.2.7. **MSEDCL** has commented that DISCOMs should be allowed to revise their Demand Estimation and Generation Adequacy once every quarter in case there is a change in the demand and supply trend.

2.2.8. **Statkraft** has commented that the forecasted demand should be made available on the website of respective SLDCs/RLDCs. The granularity of demand forecast shall at least be on an hourly basis. As availability of data in the public domain will give the correct investment signal for generators and will serve as an important signal for other power market stakeholders (traders, transmission system planners, and participants in the financial market).

2.2.9. **MP Power Management Company** has commented that the task of demand forecasting & resource adequacy should be left with Discoms & CEA, who shall eventually consider inputs from Grid Operators. The proposed amendment of determining resource adequacy by Grid Operators will not protect the interests of the end consumers, and it is proposed that this should be reviewed, so it is proposed to delete the portion "and shall include daily load curve (hourly basis) for a typical day of each month" of Regulation 5 (2) (i).

2.2.10. **PCKL** has commented that it will be very difficult to access the demand of the open access consumer and captive generating plants for the next 5 years from 1st April of next year as these consumers are not under the control of the Distribution Licensee. As per clause 21 of KERC (Conditions of licensee for ESCOMs) Regulation 2004, ESCOMs shall not procure power without approval of the Commission and are required to follow the guidelines issued by the Commission from time to time relating to preparation of load forecasts, power procurement plans and power procurement procedure. In this connection, the State Commission has to frame the Guidelines in line with the Grid Code.

2.3. **Analysis and Decision**

2.3.1. On suggestions of POSOCO and SRPC to include the anticipated addition of new types of loads, including ISTS connected bulk consumers and captive power plants in demand forecasting, the Commission believes that the existing provision is adequate to factor in such a category. On the issue of providing revision in demand estimation to take care of uncertainty due to various factors, the Commission has modified the provision to include different time periods, namely, long term, medium term, and short term.

2.3.2. Suggestions of stakeholders regarding demand forecast as per State specific framework are accepted. The Commission believes that the state specific framework to facilitate resource adequacy requirements would factor in all the concerns raised by the stakeholders. The principles provided in the regulations would act as guiding principles for state regulators while developing the state specific regulatory framework on resource adequacy based on the Model Regulations to be developed by the FOR.

2.3.3. With regard to comments on the hourly forecast, it is clarified that the said forecast is only for a typical day of each month.

2.3.4. Regulation 5 (2) (i) of the 2023 Grid Code Regulations has been modified as follows:

"(2) Demand Forecasting:

(i) Each distribution licensee within a State shall estimate the demand in its control area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, <u>in different time horizons, namely long-term, medium term and short-term</u>. The demand estimation shall be done using 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."

3. INTEGRATED RESOURCE PLANNING (Regulation 5 (2) (ii))

3.1. **Commission's Proposal**

3.1.1. The Commission had proposed the following in Regulation 5 (2) (ii) of the Draft Regulations:

"(ii) STU, based on the demand estimates furnished by the distribution licensees of the concerned State as per clause (i) of this sub-Regulation and in co-ordination with all the distribution licensees, shall estimate by 30th 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."

3.2. **Comments have been received from Shri Zakir H Rather and SRPC.**

3.2.1. **Shri Zakir H Rather (associate Prof IIT Bombay)** has commented that the state level inputs are expected to be utilized for National level resource planning and related matters, a common framework of resource planning studies, and some minimum accuracy on 5 year forecasts should be indicated in IEGC 2022.

3.2.2. **SRPC** has commented that for more accurate demand assessment by STU, inputs of STU are required and has suggested amending clause 5(2)(ii) as below:

"STU <u>(in consultation with SLDC)</u> based on the demand estimates furnished by the distribution licensees of the concerned State as per clause (i) of this sub-Regulation and in coordination with all the distribution licensees, shall estimate by 30th August every year, the demand for the entire State duly considering the diversity and losses for the next five (5) years starting from 1st April of the next year. The demand estimation shall include daily load curve (hourly basis) for a typical day of each month."

3.2.3. **BYPL** has submitted that more clarity is required on different time horizons. BYPL has requested the Commission to specify the various time horizons and provide a definition of the same.

3.3. **Analysis and Decision**

3.3.1. There is no restriction on STU for consultation with any stakeholders, including SLDC for estimating the demand for the entire State. In order to provide revision in demand estimation to take care of uncertainly due to various factors, the Commission has modified the provision to include different time periods, namely, long term, medium term and short term.

3.3.2. Regulation 5 (2) (ii) of the 2023 Grid Code Regulations have been modified as follows:

"(ii) STU or such other agency as may be designated by the State Commission, based on the demand estimates of the distribution licensees of the concerned State as per sub-clause (i) of this clause and in co-ordination with all the distribution licensees, shall estimate, in different time horizons, namely long-term, medium term and short term, the demand for the entire State duly considering the diversity of the State."

4. INTEGRATED RESOURCE PLANNING (Regulation 5 (2) (iii))

4.1. **Commission's Proposal**

4.1.1. The Commission had proposed the following in Regulation **5 (2) (iii)** of the Draft Regulations:

"(iii) Forum of Regulators may develop guidelines for demand estimation by the distribution licensees for achieving consistency and statistical accuracy by taking into consideration the factors such as economic parameters, historical data and sensitivity and probability analysis."

4.2. **Comments have been received from BYPL, RE Connect Energy, Tata Power, Prayas, GRIDCO, and Sterlite.**

4.2.1. **BYPL** has submitted that while forming the guidelines for demand estimation, the Forum of Regulators needs to consider the following factors, Weather data, Temperature, humidity, rainfall, etc. Social data: Consumer price index and Wholesale price index. Demand data: Historical consumption of electricity.

4.2.2. **RE Connect Energy** has requested that a firm timeline not exceeding 3 months be included in the clause by which the Forum of Regulators (FoR) will formulate the regulations for demand forecast that can guide the utilities further. This shall ensure that the activity is taken up by the licensees as a mandatory activity.

4.2.3. **Tata Power** has commented that a need to provide timelines for the development of guidelines, as these would act as broad principles for demand estimation by the distribution licensees. Specifying timelines (say 3 months) will expedite the process.

4.2.4. **Prayas EG** commented that demand forecasting should also be shared with the State Commissions. Distribution licensees can choose any suitable method for demand forecasting, but they should regularly analyse its accuracy and make improvements for future years. The guidelines should cover scenarios based on factors that affect demand and include captive generation, open access, energy efficiency measures, DSM measures, and policies like electric cooking, e-mobility, and industrial development. Block-wise demand curves, not just trend-based estimates.

4.2.5. **GRIDCO** has commented that the Forum of Regulators (FOR), in the first implementation year, may develop guidelines for demand estimation, based on which the distribution licensees will estimate the demand in their respective control areas, so also will STU for the State. Therefore, no timeline for distribution licensee & STU should be prescribed for the first year of implementation without stipulating the timeline for the Forum of Regulators to develop the said guidelines. From the next year onwards, after successful implementation of the load forecasting as per the prescribed guidelines of FOR, the timeline for Load forecasting by the Distribution Licensee and that by STU for the state may be adhered to.

4.2.6. **Sterlite** has commented that Energy Storage Systems (battery and Pump Storage Hydro) should also be considered separately while doing generation resource adequacy planning.

4.2.7. **Statkraft** has commented that the result of Generation Adequacy Planning should be made available on the website of respective SLDCs/RLDCs.

4.3. **Analysis and Decision**

4.3.1. The Commission has taken note of various suggestions by the Stakeholders. It would be pertinent to mention that FOR has already prepared a Model Regulations on Resources Adequacy for States, and hence, providing timelines for the same does not arise. Further a few states like Madhya Pradesh, have specified an Adequacy framework while few states such as Karnataka, Uttar Pradesh etc have issued draft regulations for stakeholders' consultations. CEA has also done state wise resource adequacy plan.

4.3.2. In view of the above discussion, the Commission decides to retain the provision as proposed in the Draft Regulations.

5. INTEGRATED RESOURCE PLANNING (Regulation 5 (3) (c))

5.1. **Commission's Proposal**

5.1.1. The Commission had proposed the following in Regulation **5 (3) (c)** of the Draft Regulations:

"(c) Generation resource procurement planning (specifying procurement from resources under State control area and regional control area) shall be undertaken in different time horizons, namely long-term, medium term and short-term to ensure

(i) adequacy of generation resources and

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

5.2. **Comments have been received from POSOCO**

5.2.1. **POSOCO** has suggested that the time horizons to be considered in long-term, medium term, and short-term planning need to be clearly specified along with their timelines. Further, POSOCO has suggested **"Normalized energy not served"** may be used in place of EENA. "Normalized ENS" is the total expected load shed due to supply shortages (MWh) as a percent (%) of the total system energy and, therefore, represents an overall percentage of system load that cannot be served. NENS provides a better understanding of the magnitude of the issue which the absolute number EENS does not provide.

5.3. **Analysis and Decision**

5.3.1. With regard to suggestions of POSOCO, it is clarified that long, medium, and short term and other details shall be as per the Guidelines issued by the Central Government under the Central Government Electricity (Amendment) Rules, 2022 or in the absence of the same to be separately specified by NLDC.

5.3.2. Accordingly, the provision as proposed in the Draft Regulations has been retained.

6. INTEGRATED RESOURCE PLANNING (Regulation 5 (3) (e))

6.1. **Commission's Proposal**

6.1.1. The Commission had proposed the following in Regulation **5 (3) (e)** of the Draft Regulations:

"(e) Based on the information received under clause (iv) of this sub-Regulation and after considering inter alia the national level planning reserve margin, share of each State in the national coincident peak, seasonal requirements of States and possibility of sharing generation capacity seasonally among States, NLDC shall carry out a simulation by 31st October every year, to assist the States in drawing their optimal generation resource adequacy plan. While carrying out the simulation, NLDC shall also take into consideration the information related to demand estimation, generation planning and related matters as available with CEA. The simulation carried out by NLDC for this purpose shall be considered merely an aid to the distribution licensees in the respective States in their exercise of generation resource adequacy planning and the distribution licensees shall be responsible for all commercial decisions on generation resource procurement."

6.2. **Comments have been received from POSOCO and Tata Power.**

6.2.1. **POSOCO** has commented that NLDC is required to carry out a simulation based study to assist the States in drawing their optimal generation resource adequacy plan by 31st October every year, which is just one month after the submission of the results by STU. Considering the envisaged complexities in such an exercise on account of data non-availability (assumptions to be made) and validation of same with stake holders, it is suggested that the time window of one month may be reviewed.

6.2.2. **Tata Power** has commented that the role of NLDC should not be merely to provide aid in demand estimation. Since NLDC is equipped with the required expertise and skills, it should also ensure that the demand estimation made by distribution licensees is accurate.

6.3. **Analysis and Decision**

6.3.1. The suggestions of POSOCO to increase the timeline for doing the study are not accepted. With regard to suggestions of Tata Power, it is clarified that demand estimation shall be as per State specific guidelines. Regulation 5 (3) (e) of the 2023 Grid Code Regulations has been modified as follows:

"(e) Based on the information received under sub-clause (d) of this clause and after considering inter alia the national level planning reserve margin, share of each State in the <u>regional</u> and national coincident peak, seasonal requirements of States and possibility of sharing generation capacity seasonally among States, NLDC shall carry out

a simulation, to assist the States in drawing their optimal generation resource adequacy plan. While carrying out the simulation, NLDC shall also take into consideration the information related to demand estimation, generation planning and related matters as available with CEA. The simulation carried out by NLDC for this purpose shall be considered merely as an aid to the distribution licensees in the respective States in their exercise of generation resource adequacy planning and the distribution licensees shall be responsible for all commercial decisions on generation resource procurement"

7. INTEGRATED RESOURCE PLANNING (Regulation 5 (3) (f))

7.1. Commission's Proposal

7.1.1. The Commission had proposed the following in Regulation 5 (3) (f) of the Draft Regulations:

"(f) After considering the demand forecasting and the generation resource procurement planning carried out based on the principles specified under this Regulation, each distribution licensee shall ensure demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year. Failure of a distribution licensee to meet the generation resource adequacy target approved by the SERC shall render the concerned distribution licensee liable for payment of resource adequacy non-compliance charge as may be specified by the respective SERC."

7.2. Comments have been received from Tata Power, POSOCO, PSPCL and KSEBL

7.2.1. **Tata Power** has suggested an addition in clause **5 (3) (f) as follows:**

"However, resource adequacy demonstrated by the Discoms shall be subject to modification in case of delay of commissioning of generation projects, sudden/unprecedented load growth, exit of open access consumers from supply area, and any other factor not under their control without any penalty."

7.2.2. **POSOCO** has suggested a modification in the clause as follows:

"(f) After considering the demand forecasting …. SERC for the next five (5) years starting 1st April of the next year. <u>Adequacy statement containing a list of such resources along with associated capacities shall be submitted to the respective STU and SERC</u>… …. specified by the respective SERC."

7.2.3. **PSPCL and KSEBL** have requested to remove the penalty provision from the clause.

7.2.4. **MSEDCL** has commented that resource adequacy non-compliance charges should not be imposed on distribution licensees having sufficient contracted generation capacity.

7.2.5. **GRIDCO** has commented that no timeline may be fixed for distribution licensees, STUs, and NLDCs for Generation Resource Adequacy Planning in the first year (April to March). GRIDCO has also requested the Commission to consider that a non-compliance charge does not apply if there is a lack of adequate generation resources due to Force Majeure conditions, natural disasters, or factors beyond the control of the distribution licensee.

7.3. Analysis and Decision

7.3.1. The timeline for demonstrating generation resource adequacy has been removed, and the same would be as per the timelines specified by the SERC.

7.3.2. Further, the non-compliance charges shall be as specified by SERCs, and hence, the details of when the same should be levied shall be considered by SERCs. Regulation 5 (3) (f) of the 2023 Grid Code Regulations as follows:

"(f) After considering the demand forecasting and the generation resource procurement planning carried out based on the principles specified under this Regulation, each distribution licensee shall ensure demonstrable generation resource adequacy for such period as specified by the respective SERC. Failure of a distribution licensee to meet the generation resource adequacy target approved by the SERC shall render the concerned distribution licensee liable for payment of resource adequacy noncompliance charge as may be specified by the respective SERC."

8. INTEGRATED RESOURCE PLANNING (Regulation 5 (3) (g))

8.1. Commission's Proposal

8.1.1. The Commission had proposed the following in Regulation 5 (3) (g) of the Draft Regulations:

"(g) For the sake of uniformity in approach and in the interest of optimality in generation resource adequacy in the States, 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."

8.2. Comments have been received from BYPL, Enel, Greenko, ReNew, WIPPA, NSEFI, Tata Power, Hero Future Energy, RE Connect Energy MSEDCL, IEX, GRIDCO and POSOCO.

8.2.1. **BYPL** has commented that a timeline needs to be defined for the Forum of Regulators' development of model Regulations.

8.2.2. **Enel, Greenko, ReNew, WIPPA, NSEFI, Tata Power, and Hero Future Energy** have suggested a modification in the clause to insert a levy of penalty for non-compliance of such target in the FOR model regulations.

8.2.3. **RE Connect Energy** has requested that the role of QCAs/forecasters should also be included in the model regulation.

8.2.4. **IEX** has proposed two changes to improve resource adequacy. Firstly, discoms should have the option to procure only capacity instead of both capacity and energy.

8.2.5. **Prayas EG** has requested that the time horizon for adequacy planning be increased from 5 years to 10 years. Prayas EG has also requested the commission to defer the implementation of the penal provision for 2-3 years.

8.2.6. **POSOCO** has suggested that these model guidelines may include the roles and responsibilities of different agencies, sources of inputs, timelines for submission and methodology for assessing compliance.

8.3. Analysis and Decision

8.3.1. The Commission has noted the suggestions of the stakeholders. The FOR has already developed a Model Regulations on Resource Adequacy for states to adopt and as mentioned earlier, some states have adopted the same subject to state specific conditions. The framework provided by the Commission is to complement the guidelines issued by the Central Government under Rule 16 of the Electricity (Amendment) Rules, 2022.

8.3.2. Accordingly, the provision as proposed in the Draft Regulations has been retained.

9. INTEGRATED RESOURCE PLANNING (Regulation 5 (4) (a))

9.1. **Commission's Proposal**

9.1.1. The Commission had proposed the following in Regulation **5 (4) (a)** of the Draft Regulations:

"(4) Transmission resource adequacy assessment

(a) CTU shall undertake assessment and planning of the inter-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) adequate power transfer capability across each flow-gate;

(ii) import and export capability for each control area;

(iii) import and export capability between regions; and

(iv) cross-border import and export capability."

9.2. **Comments have been received from Enel, Greenko group, ReNew, Hero Future Energy, National Solar Energy Federation of India, Tata Power, GRIDCO, CTU, SRPC and POSOCO.**

9.2.1. **Enel, Greenko group, ReNew, Hero Future Energy, National Solar Energy Federation of India, and Tata Power** have suggested an additional insertion in the clause:

> *"Transmission deferral – ESS derive most their value inter alia from averting the installation of excessive amounts of transmission infrastructure. CTU/STU should optimize transmission system requirement with co-located ESS, particularly while designing evacuation system for wind-solar projects located in such resource rich area.*
>
> *Transmission system for RE dense area shall be developed for lower peak and such energy may be stored in ESS for dispatch in non-RE hours."*

9.2.2. **GRIDCO** has suggested that penal provision on CTU may be prescribed in the above Grid Code for their failure to provide adequate power transfer capability across each flow-gate, import and export capability for each control area, import and export capability between regions and cross-border import and export capability.

9.2.3. **CTUIL** has suggested substituting "account" with "<u>consideration import and export</u> capability<u> between regions"</u> in clause (a).

9.2.4. **SRPC** has suggested the modification in the clause:

"CTU, <u>in consultation with RPC(s)/CEA</u>, shall undertake assessment …":

SRPC has commented that RPC(s) & CEA may be consulted for the planning of the ISTS. Additionally, time limits may be defined for CTU/STU.

9.2.5. **POSOCO** has commented that the section on Transmission Resource Adequacy assessment is very short. The planning of ISTS and STU systems needs to be carried out as per provisions of the CEA Manual on Transmission Planning criteria and other CEA/CERC Regulations and has suggested the modification/addition in the clause

"(a)…

<u>i. Manual on Transmission Planning Criteria issued by CEA</u>

<u>ii. Central Electricity Authority (Technical Standards for Connectivity to the Grid) 2007</u>

<u>iii. Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State adequate power transfer capability across each flow-gate;</u>

<u>iv. Central Electricity Regulatory Commission (Grant of Connectivity, Long- Term Access and Medium-Term Open Access in interstate transmission and related matters) Regulations 2009</u>

(ii) import and export capability for each control area;

(iii) import and export capability between regions; and

(v) cross-border import and export capability.

(b) STU shall undertake assessment and planning of the intra-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) import and export capability across ISTS and STU interface; and

(ii) <u>adequate Transmission System</u>"

9.3. **Analysis and Decision**

9.3.1. The Commission has noted the suggestions of the stakeholders. On the issue of transmission deferral and use of ESS for optimum use of the transmission capacity, the Commission is of the opinion that the existing provisions envisage the optimum utilisation of the transmission system by taking into consideration all techno-economic alternatives. The Commission agrees with the view of the CTUIL that transmission planning of ISTS is carried out in terms of the Act, Regulations, CEA Planning Criteria, CEA Technical Standards for Connectivity, etc. Transmission planning inter-alia includes the transfer capability between regions and cross borders.

9.3.2. Accordingly, the provision as proposed in the Draft Regulations has been retained.

10. INTEGRATED RESOURCE PLANNING (Regulation 5 (4) (b))

10.1. **Commission's Proposal**

10.1.1. The Commission had proposed the following in Regulation **5 (4) (b)** of the Draft Regulations:

"(b) STU shall undertake assessment and planning of the intra-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) import and export capability across ISTS and STU interface; and

(ii) adequate power transfer capability across each flow-gate."

10.2. **Comments have been received from GRIDCO, Tata Power, Greenko, Enel, NSEFI, DVC, ReNew, Tata Power, and SRPC.**

10.2.1. **Prayas EG** has also commented that state level planning should be in accordance with or better than the current processes and could consider a longer time horizon. IEGC should also be in consonance with other rules, regulations and guidelines by Central Agencies like the Ministry of Power (MoP) and Central Electricity Authority (CEA).

10.2.2. **GRIDCO** has commented that there should be penal provision on STU in the above Grid Code for their failure to provide adequate import and export capability across ISTS and STU interface and adequate power transfer capability across each flow gate.

10.2.3. **Tata Power** has suggested an additional insertion in the clause:

“Transmission planning, particularly that being planned for evacuation for RE power should be done in a manner that the length of the dedicated transmission line is minimised as much as possible.”

Tata Power has commented that the transmission adequacy planning code should cover the adequacy of intra-state transmission systems too.

10.2.4. **Greenko Group, Enel, and NSEFI** have requested an additional Chapter insertion, which should include the following points:

(i) Dedicated transmission system for generation assets / PSPs, that are distantly far located from grid connection, should be reduced to ~ 25 KM.

(ii) Advance strategic transmission planning needs to be carried out for PSPs to provide transmission system ahead of the start date of operation of such assets.

10.2.5. **DVC** has commented that, as far as the transmission planning is concerned, DVC T&D is treated like other STUs. Presently, augmentation/planning of New Transmission elements is under the purview of STU. However, SLDC is consulted prior to finalisation of the plan.

10.2.6. **Greenko Group, ReNew, NSEFI, Tata Power and Enel have** suggested the insertion of an Energy storage system in the clause. It was suggested that while Generation resource planning/demand forecasting, distribution licensees must access the requirement of ESS in long term, medium term as well as in short term period. Further, under scenarios wherein the distribution licensee anticipates any excess generation from RE resources, instead of curtailing, the same can be stored and utilised during non-RE hours.

10.2.7. **SRPC** has commented that Time limits may be defined for CTU/STU.

10.3. **Analysis and Decision**

10.3.1. The Commission has noted the suggestions of the stakeholders. The transmission planning of ISTS is carried out in terms of the Act, Regulations, CEA Planning Criteria, CEA Technical Standards for Connectivity, etc. The Commission believes that the existing provision proposed in the draft grid code is adequate to take into consideration the comments received from the stakeholders. For monetising the ancillary support capability of various technologies like ESS, the appropriate provisions could be made in the Ancillary Service Regulations instead of IEGC. Accordingly, the Commission decides to retain the provision proposed in the Draft Regulations.

CHAPTER-3 - CONNECTION CODE

1. General (Regulation 6 (4))

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation 6(4) of the Draft Regulations:

"6(4) After grant of connectivity and prior to the trial run for declaration of commercial operation, the tests as specified under this Code shall be performed"

1.2. **Comments have been received from POSOCO, MPPMCL and NTPC**

1.2.1. **POSOCO** has commented that in the Report of the Expert Group for draft IEGC, several tests were mentioned for various power system elements. These tests were to be performed before proceeding to trial run operation. The timings of these tests are very important, and, therefore, they shall be included as a necessary requirement before any element proceeds to trial run operation.

1.2.2. **MPPMCL** has commented that Clause 4.8 (Schedule of assets of Regional Grid) of IEGC 2010 has been dropped. Hence a rationale for dropping the same may be provided. And, in the absence of a schedule of declared assets, how will demarcation of ownership, control, and responsibility over the assets be established?.

1.2.3. **NTPC** has commented that the tests as specified under this Code should be performed before a certificate of successful trial run is issued,"

1.3. **Analysis and Decision**

1.3.1. The tests that are to be performed on various power system elements have been specified in the Commissioning and Commercial Operation Code. Some of the tests are conducted while the power system element is under trial operation. Hence, the tests are required to be conducted prior to declaration of COD but all tests may not be conducted prior to proceeding to the trial run.

1.3.2. The list of assets, as suggested by MPPMCL, is already covered under "list of important elements" published by RLDC under Regulation 29(1)(b) of the 2023 Grid Code 2023.

1.3.3. Regulation 6 (4) of the 2023 Grid Code has been modified as follows:

"6 (4) After grant of connectivity and prior to the declaration of commercial operation, the tests as specified under Chapter-5 of these regulations shall be performed."

2. COMPLIANCE WITH EXISTING RULES AND REGULATIONS (Regulation 7 (1))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation 7(1) of the Draft Regulations:

"7(1) All Users connected to or seeking connection to the grid shall comply with all the applicable regulations as enacted or amended from time to time, such as:"

2.2. **Comments have been received from POSOCO**

2.2.1. **POSOCO** suggested adding the following regulations of CEA in the clause,

"1) Central Electricity Authority (Grid Standards) Regulations, 2010

2) CEA (Cyber Security in Power Sector) Guidelines, 2021"

2.3. **Analysis and Decision**

2.3.1. The Commission has added the following to Regulation 7 (1) of the 2023 Grid Code:

"(j) Central Electricity Authority (Grid Standards) Regulations, 2010.

(k) Central Electricity Authority (Cyber Security in Power Sector) Guidelines, 2021.

(l) Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023"

3. PROCEDURE FOR CONNECTION (Regulation 8 (2))

3.1. **Commission's Proposal**

3.1.1. The Commission had proposed the following in Regulation 8(2) of the Draft Regulations:

"8(2) NLDC, in coordination with RPCs and RLDCs after due consultation of stakeholders, shall publish a detailed procedure covering modalities for first time energization and integration of new or modified power system element. The procedure shall specify requirements for integration with the grid such as protection, telemetry and communication systems, metering, statutory clearances and modelling data requirements for system studies"

3.2. **Comments have been received from POSOCO**

3.2.1. **POSOCO** has commented that the timeline for submission of data to be used for system study may be mentioned in the detailed procedure as the data is to be used as per section 10 of the same regulations.

3.3. **Analysis and Decision**

3.3.1. Considering suggestions of POSOCO, the clause has been modified to include timelines. Regulation 8 (2) of the 2023 Grid Code Regulations has been modified as follows:

"8 (2) NLDC, in coordination with RPCs and RLDCs after due consultation of stakeholders, shall prepare a detailed procedure covering modalities for first time

energization and integration of new or modified power system element and submit for approval of the Commission. The procedure shall specify requirements for integration with the grid such as protection, telemetry and communication systems; metering; statutory clearances; modelling data requirements for system studies and timeline for submission of data for system study."

4. PROCEDURE FOR CONNECTION (Regulation 8 (4))

4.1. **Commission's Proposal**

4.1.1. The Commission had proposed the following in Regulation 8(4) of the Draft Regulations:

"8 (4)SLDC shall prepare procedure for first time energization of new or modified power system elements to intra-State transmission system. In the absence of such procedure of SLDC, the NLDC procedure shall apply for the elements of 220 kV and above (132 kV and above in case of North Eastern region)."

4.2. **Comments have been received from POSOCO and Torrent Power**

4.2.1. **POSOCO** has suggested that notwithstanding the first time energization FTC procedure compiled by SLDCs, all constituents should abide by the NLDC procedure for elements mentioned in the same.

4.2.2. **Torrent Power Limited** has suggested that CERC cannot direct SLDC to specify the procedure to be followed for energization of new/ modified power system as SLDC is within the jurisdiction of SERCs/ JERC. Even at present, SLDC follows the necessary system and mechanism for the energization of new or modified power systems.

4.3. **Analysis and Decision**

4.3.1. The first time energization procedure for elements covered through such Procedure published by NLDC, shall be applicable for all constituents covered under the said Procedure.

4.3.2. Since a first time energisation is a grid related event where system studies to ensure grid security is required to be undertaken, SLDCs have been suggested preparing a first time energization, which SLDCs may issue with approval of SERC/JERC as required.

5. CONNECTIVITY AGREEMENT (Regulation 9 (1))

5.1. **Commission's Proposal**

5.1.1. The Commission had proposed the following in Regulation 9 (1) of the Draft Regulations:

"9(1) In case of users seeking connectivity to the ISTS under GNA Regulations, Connectivity Agreement shall be signed between such users and the CTU"

5.2. **Comments have been received from POSOCO and DVC**

5.2.1. **POSOCO** has suggested that in case of transmission systems involving more than one transmission licensee, the need for proper coordination of protection settings and data sharing with LDCs becomes important. The connectivity agreement can broadly cover the details about the site responsibility schedule covering these aspects.

5.2.2. **DVC** suggested that connectivity with the DVC network (declared as ISTS for Tariff purposes) by any other entity, suitable provision may be incorporated because the T&D network of DVC right from voltage level 400 kV to 33 kV, has been declared as ISTS Network.

5.3. **Analysis and Decision**

5.3.1. Suggestions of POSOCO have been accepted, and accordingly, the clause has been modified.

5.3.2. CTU is responsible for discharging all functions of planning and co-ordination relating to inter-State transmission systems as per the Act. Accordingly, the Connectivity Agreement shall be signed with the CTU.

5.3.3. Regulation 9 (1) of the 2023 Grid Code Regulations has been modified as follows:

"9 (1) In case of users seeking connectivity to the ISTS under GNA Regulations, Connectivity Agreement shall be signed between such users and CTU. In case of multiple transmission licensees connected at same station, the Site Responsibility Schedule including the responsibility for operation & protection coordination and data sharing among the licensees, shall be specified in the Connectivity Agreement."

6. CONNECTIVITY AGREEMENT (Regulation 9 (2))

6.1. **Commission's Proposal**

6.1.1. The Commission had proposed the following in Regulation 9 (2) of the Draft Regulations,

"9(2) In case of an inter-State transmission licensee, Connectivity Agreement shall be signed between such licensee and CTU after the award of the project and before physical connection to ISTS"

6.2. **Comments have been received from CTU and POSOCO**

6.2.1. **CTU** has suggested adding 'STU' along with inter-State transmission licensee.

6.2.2. **POSOCO** has suggested an addition to the clause as follows:

"User seeking connectivity shall submit the necessary technical data to CTU as specified in CTU procedure in line with CERC GNA Regulations. The same shall be passed on to RLDC/NLDC for facilitating any interconnection."

POSOCO has commented that it has been observed that many times sufficient data is not made available to RLDC/NLDC, citing restrictions owing to proprietary data.

6.3. **Analysis and Decision**

6.3.1. Considering suggestions of CTU, an additional clause has been added to the regulation as follows:

"(3) In case of intra-State transmission system getting connected to inter-State transmission system, Connectivity Agreement shall be signed between intra-State transmission licensee, CTU and inter-State transmission licensee after the award of the project and before physical connection to ISTS."

6.3.2. User seeking connectivity shall submit the necessary technical data to CTU under the GNA Regulations. CTU shall share a copy of the same with RLDC/NLDC.

7. TECHNICAL REQUIREMENTS (Regulation 10 (1), 10(2))

7.1. **Commission's Proposal**

7.1.1. The Commission had proposed the following in Regulation 10 (1) and (2) of the Draft Regulations:

"10(1) NLDC or RLDC, as the case may be, 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, if any. The connectivity grantee, transmission licensee and SLDC/STU shall furnish all technical data including that of its embedded generators and other elements to the CTU and NLDC or RLDC, as the case may be, for necessary technical studies.

10(2) Similar exercise shall be done by SLDC 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)"

7.2. **Comments have been received from POSOCO and APP**

7.2.1. **POSOCO** suggested modifying the clause as follows:

"NLDC or RLDC, as the case may be, in consultation with CTU <u>and concerned STUs/SLDCs,</u> shall carry out a joint system study *<u>at least</u>* six (6) months before the expected date of first energization of a new power system element to identify operational constraints, if any. <u>In case of constraints, CTU and RLDC/NLDC shall jointly explore short-term measures for facilitating the integration of the element, subject to grid security</u>. The connectivity *grantee*, transmission licensee, and SLDC/STU shall furnish all technical data, including that of its embedded generators and other elements to the CTU and NLDC or RLDC, as the case may be, for necessary technical studies. <u>NLDC, in consultation with CTU, shall publish a detailed procedure covering modalities for carrying out the interconnection studies as specified in clause 10 (1). The procedure shall specify requirements for modelling data requirements for system studies, the timeline for various stages involved etc. Respective SLDCs shall also prepare similar procedures for intra-</u>

State transmission systems. In the absence of such procedure of SLDC, the NLDC procedure shall apply for the intra-state elements.”

An alternative may be that the modalities for carrying out these studies (such as the timeline to submit the data by the users) are covered in the First time energisation procedure.

POSOCO has suggested that for 400 kV & above systems, the system study should be carried out jointly by CTU, STU, SLDC, and RLDC irrespective of ISTS or intra-state systems.

7.2.2. **APP** suggested carrying out system studies (load flow, short circuit, and stability analysis) and power system studies (transient over voltage analysis and insulation coordination).

7.3. **Analysis and Decision**

7.3.1. Considering the suggestions of POSOCO, Regulation 10 (1) of the 2023 Grid Code Regulations have been modified as follows:

“10 (1) NLDC or RLDC, as the case may be, in consultation with CTU, STU or SLDC, as the case may be, 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, if any. In case of constraints, CTU, NLDC or RLDC, as the case may be and SLDC shall identify measures for facilitating the integration of the element, subject to grid security. The connectivity grantee, transmission licensee and SLDC/STU shall furnish all technical data including that of its embedded generators and other elements to the CTU and NLDC or RLDC, as the case may be, for necessary technical studies.

10(2) Similar exercise shall be done by SLDC 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)”

10(3) NLDC shall publish a detailed procedure covering modalities for carrying out the interconnection studies.”

7.3.2. With regard to suggestions of APP, we are of the view that details of studies may be included by the NLDC in the detailed Procedure to be issued by NLDC.

8. DATA AND COMMUNICATION FACILITIES (Regulation 11 (1))

8.1. **Commission’s Proposal**

8.1.1. The Commission had proposed the following in Regulation 11 (2) of the Draft Regulations:

“11(2) The associated communication system to facilitate data flow up to appropriate data collection point on CTU system including inter-operability

requirements shall also be established by the concerned user as specified by CTU in the Connectivity Agreement"

8.2. **Comments have been received from POSOCO, RE Connect Energy, and Zakir H Rather**

8.2.1. **POSOCO** suggested modifying the clause as follows:

"All Users, STU and *CTU* shall provide systems to telemeter power system parameters such as status of switches, power flow, frequency, voltage, tap, /controller settings, etc required for supervision and performance assessment of power system elements. in line with interface requirements as mentioned in the NLDC First time energization procedure."

8.2.2. **RE Connect Energy** suggested that the telemetry data can also be simultaneously made available on the scheduling portals of respective RLDCs/SLDCs so that the QCA/forecaster or the RE generators can fetch it using API for the purpose of efficient forecasting**.**

8.2.3. **Sh. Zakir H Rather (Associate Prof IIT Bombay)** commented that the agency/stakeholder responsible for data collection with its roles and responsibilities are apparently not covered in the draft. Moreover the draft does not mention broader guidelines to be followed for data collection, and its extent, .

8.3. **Analysis and Decision**

8.3.1. With regard to suggestions of POSOCO, it is clarified that power system parameters to be telemetered shall be as per the CEA Standards for communications and the CERC Communication System Regulations.

8.3.2. The suggestions of RE Connect to provide telemetered data at scheduling portals are not accepted since power system data shall be shared only with access control to ensure grid security. Accordingly, the data that can be shared shall be as decided by the system operator.

8.3.3. The roles and responsibilities of data collection shall be as per the CEA Standards for communications and the CERC Communication System Regulations.

8.3.4. The provision as proposed in the Draft Regulations has been retained.

9. DATA AND COMMUNICATION FACILITIES (Regulation 11 (3))

9.1. **Commission's Proposal**

9.1.1. The Commission had proposed the following in Regulation 11 (3) of the Draft Regulations:

"3) All users*, STU and participating entities in case of cross-border trade shall provide, in coordination with CTU, the required facilities at their respective ends as specified in the connectivity agreement. The communication system along with data links provided for speech and real time data communication shall be monitored in real time by all users, CTU, STU, SLDC and RLDC to ensure high reliability of the communication links."*

9.2. **Comments have been received from CPPA, POSOCO, SRPC and HPSLDC**

9.2.1. **POSOCO** has suggested adding new clause as follow:

“DISCOMs in consultation with the respective SLDC would also establish a system of measuring /estimating distributed generation such as rooftop solar etc. This shall be consolidated state wise at the SLDC level and transmitted to RLDCs and therefrom to NLDC.”

9.2.2. **SRPC** has suggested modifying the clause as follows:

“(3) …The communication system along with data links provided for speech <u>protection and regulation/control</u> and real time data communication shall be monitored…”

SRPC has commented that for AGC and other Regulatory Measures, implementation control may be required

SRPC has also suggested adding a new clause as follows:

“ISTS and Intra-state transmission licensees, CTU & STU would share mutually their communication system for grid operation requirements like voice, data etc.”

9.2.3. **HPSLDC** suggested adding a new clause as follows:

“(4) All the State entities connected on 66 kV and above network shall provide reliable real time data communication connectivity/ Telemetry with SLDC/ RLDC control centre, preferably on Fiber optic network.

(5) In case reliable data is not provided at SLDCs/ RLDCs by the State entities affecting the drawl & demand of the State/ Region/ Nation, then after issuance of a notice by the concerned RLDC/ SLDC, the defaulting state entities will be required to establish a reliable communication with RLDC/ SLDC control centre within 01 month from the date of issuance of such notice. If the defaulting State entity (ies) is / are still unable to provide the reliable data communication, then there shall be a provision of penalty per day per station for non-reporting of real time data of their respective station.”

9.3. **Analysis and Decision**

9.3.1. The Commission has noted the suggestions of the stakeholders. The provision as proposed in the Draft Regulations has been retained.

CHAPTER-4 - PROTECTION CODE

1. General (Regulation 12 (2) (a & d))

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation 12 (2) (a & d) of the Draft Regulations:

"(2) There shall be a uniform protection protocol for the users of the grid:

(a)for proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended *operation of protection system"*

"(d) to ensure healthiness of recording equipment including time synchronization"

1.2. **Comments have been received from SRPC and POSOCO**

1.2.1. **SRPC** has suggested adding a new clause to be in line with CEA Connectivity Regulations:

"Further for providing requisite protection for safeguarding its system from the faults originating in the grid."

1.2.2. **POSOCO** suggested modifying as follows:

"(a) For proper co-ordination of protection system in order <u>to protect the equipment / system from abnormal operating conditions and</u> to isolate …;

(d) to ensure healthiness of recording equipment including <u>triggering criteria and</u> time synchronization."

1.3. **Analysis and Decision**

1.3.1. Suggestions of SRPC and POSOCO have been accepted.

1.3.2. Regulation 12 (2) (a) & (d) of the 2023 Grid Code Regulations have been modified as follows:

"(2) There shall be a uniform protection protocol for the users of the grid:

(a) for proper co-ordination of protection system in order to protect the equipment/system from abnormal operating conditions, isolate the faulty equipment and avoid unintended operation of protection system;

…..

(d) to ensure healthiness of recording equipment including triggering criteria and time synchronization; and"

2. PROTECTION PROTOCOL (Regulation 13 (1))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation 13 (1) of the Draft Regulations:

"(1) All users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per the CEA Technical Standards

for Construction, the CEA Technical Standards for Connectivity, the CEA (Grid Standards) Regulations, 2010 and the CEA Technical Standards for Communication."

2.2. **Comments have been received from POSOCO**

2.2.1. POSOCO suggested modifying as follows:

"All users …. for Communication <u>and any other applicable CEA standards specified from time to time."</u>

2.3. **Analysis and Decision**

2.3.1. The Commission has accepted the suggestions of the POSOCO.

2.3.2. Regulation 13 (1) of the 2023 Grid Code Regulations has been modified as follows:

"13 (1) All users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA (Grid Standards) Regulations, 2010, the CEA Technical Standards for Communication and any other applicable CEA Standards specified from time to time."

3. PROTECTION PROTOCOL (Regulation 13 (3))

3.1. **Commission's Proposal**

3.1.1. The Commission had proposed the following in Regulation 13 (3) of the Draft Regulations:

"(3) RPC shall develop the protection protocol and revise the same, after review from time to time, in consultation with the stakeholders in the concerned region, and in doing so shall be guided by the principle that minimum electrical protection functions for equipment connected with the grid shall be provided as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA Technical Standards for Communication, the CEA (Grid Standards) Regulations, 2010, the CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, and any other CEA standards specified from time to time."

"(4) The protection protocol in a particular system may vary depending upon operational experience. Changes in protection protocol, as and when required, shall be carried out after deliberation and approval of the concerned RPC"

3.2. **Comments have been received from SRPC, CESC and POSOCO**

3.2.1. **SRPC** has suggested adding a new clause:

"Violation of the protection protocol of the region shall be brought to the notice of concerned RPC by RLDC/SLDC."

3.2.2. **CESC** has commented that internal network elements should not be included under these parameters as it is not required and will not be manageable in terms of cost and manpower requirement and has suggested the following modification:

"The Protection protocol in a particular system <u>which are part of National Grid</u> may vary depending …."

3.2.3. **POSOCO** suggested adding that "NPC shall harmonize the protection protocol of all RPCs" at the end of the clause.

3.3. **Analysis and Decision**

3.3.1. The suggestions of SRPC have been accepted. The Commission has added a new Clause 13 (5) to the 2023 Grid Code Regulations:

"13 (5) Violation of the protection protocol of the region shall be brought to the notice of concerned RPC by the concerned RLDC or SLDC, as the case may be."

3.3.2. With regard to suggestions of CESC, it is clarified that since the grid is integrated, the elements that may affect the integrated operation of the grid shall be decided by RLDC/NLDC in consultation with stakeholders. Hence the suggestion of CESC is not accepted.

4. PROTECTION SETTINGS (Regulation 14 (1))

4.1. **Commission's Proposal**

4.1.1. The Commission had proposed the following in Regulation 14 (1) of the Draft Regulations:

"14(1) RPCs shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders of the respective region, from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the respective RPC."

4.2. **Comments have been received from WRPC and Power Grid**

4.2.1. **WRPC** has suggested inserting the following at the end of the clause:

"Whenever changes in the network are anticipated, RLDC/SLDC shall inform the network changes along with the details well in advance (at least 45 days in advance) to respective RPC. The study data dynamic and base case (peak-off peak cases) files required for review of protection settings shall be provided by POSOCO/CTU, along with the above data to respective RPCs."

4.2.2. **Power Grid** suggested replacing "settings" with "philosophy". Power Grid has commented that RPC may review protection philosophy in line with Ramkrishna Task Force guidelines in place of IED specific protection settings.

4.3. **Analysis and Decision**

4.3.1. The suggestions of WRPC have been accepted. Accordingly, Regulation 14 (1) of the 2023 Grid Code Regulations has been modified as follows:

"14 (1) RPCs shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders of the respective region, from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the respective RPCs. The data including base case (peak and off-peak cases) files for carrying out studies shall be provided by RLDC and CTU to the RPCs:"

4.3.2. With regard to suggestions of the Power Grid, it is clarified that changes in protection philosophy are covered under Regulation 13(4) of the Grid Code and no change is required in the instant Regulation. Further, reference to 'Ramakrishna guidelines' has already been made under Clause 3(1) of Annexure-1 to the Grid Code.

5. PROTECTION SETTINGS (Regulation 14 (2))

5.1. Commission's Proposal

5.1.1. The Commission had proposed the following in Regulation 14 (2) of the Draft Regulations:

"(2) All users connected to the grid shall:

(a) furnish the protection settings implemented for each element to respective RPC in a format as prescribed by the concerned RPC;

(b) obtain approval of the concerned RPC for (i) any revision in settings, and (ii) implementation of new protection system;

(c) intimate to the concerned RPC about the changes implemented in protection system or protection settings within a fortnight of such changes;

(d) ensure correct and appropriate settings of protection as specified by the concerned RPC.

(e) ensure proper coordinated protection settings."

5.2. Comments have been received from TS Transco, SRPC, CESC, POSOCO, Adani Power and Enel

5.2.1. **TS TRANSCO** suggested modifications as follows:

"(a). …. the concerned RPC <u>in consultation with the stakeholders in the concerned region.</u>

(b). …implementation of new protection system <u>if the same is not as per protection protocol</u>."

5.2.2. **SRPC** has suggested the following modifications for speedy implementation of revised settings,

"(b). Obtain <u>concurrence</u> of the concerned RPC for (i) any revision in settings, and (ii) implementation of new protection system <u>for voltages 220 kV and above</u>."

5.2.3. **CESC** has suggested that internal network elements should not be included under these parameters as they are not required and will not be manageable in terms of cost and manpower requirement. Instead they should be limited to the elements which are part of the national grid.

5.2.4. **POSOCO** suggested modifying the clause as follows:

"(2) All users connected to the grid <u>at voltage level of 132 kV & above (33 kV & above for RE plants)</u>.

…

(e) ensure proper coordinated protection settings <u>as approved by RPC."</u>

5.2.5. **Adani Power** commented that details of all line and switchyard protection be shared.

5.2.6. **Enel** has requested RPCs to provide the setting details of the user bay at the PGCIL end, other feeder settings and the upstream transformer settings. This ensures that the user coordinates the setting w.r.t. upstream network w.r.t. time and current.

5.3. **Analysis and Decision**

5.3.1. The suggestions of stakeholders are a matter of coordination at the RPC level and may be finalised at the RPC level while finalising the formats by RPC in consultation with stakeholders. Further, in view of the suggestions of CESC, Regulation 14(5) has been inserted as follows:

"(5) The elements of network below 66kV and radial in nature which do not impact the National Grid may be excluded as finalized by the respective RPC."

6. PROTECTION SETTINGS (Regulation 14 (3) (a))

6.1. **Commission's Proposal**

6.1.1. The Commission had proposed the following in Regulation 14 (3) (a) of the Draft Regulations:

"14(3) RPCs shall:

(a) maintain a centralized database in respect of their respective region containing details of relay settings for grid elements connected to 220 kV and above (132 kV and above in NER)."

6.2. **Comments have been received from Torrent Power Limited and WRPC**

6.2.1. **Torrent Power Limited** suggested that instead of specifying the voltage level of 220 kV, reference should be given to interface points.

6.2.2. **WRPC** has suggested that RLDCs should also maintain such a database in addition to RPC. Further, WRPC has suggested adding "The changes in the network and protection settings of grid elements connected to 220kV and above shall be informed to RPCs by CTU and STUs."

6.3. **Analysis and Decision**

6.3.1. The suggestions of WRPC have been accepted. Accordingly, Regulation 14 (3) (a) has been modified, and new Regulation 14(3)(4) has been inserted as follows:

"14 (3) RPCs shall:

(a) maintain a centralized database and update the same on periodic basis in respect of their respective region containing details of relay settings for grid elements connected to 220 kV and above (132 kV and above in NER). <u>RLDCs shall also maintain such database."</u>

"14(3)(4) The changes in the network and protection settings of grid elements connected to 220kV and above (132 kV and above in NER) shall be informed to RPCs by CTU and STUs, as the case may be."

6.3.2. Suggestions of Torrent power are not accepted due to the integrated nature of the power system. The grid elements connected at a specific voltage level need to be monitored at the RPC level.

7. PROTECTION SETTINGS (Regulation 14 (3) (b))

7.1. **Commission's Proposal**

7.1.1. The Commission had proposed the following in Regulation 14 (3) (b) of the Draft Regulations:

"14(3)(b) - carry out detailed system studies, twice a year, for protection settings and advise modifications / changes, if any, to the CTU and to all users and STUs of their respective regions."

7.2. **Comments have been received from SRPC, SJVN and WRPC**

7.2.1. **SRPC** has suggested carrying out detailed system studies once a year instead of twice a year.

7.2.2. **SJVN** has suggested that detailed system studies reports may be shared with generators also.

7.2.3. **WRPC** has suggested inserting the following at the end of the clause:
"The dynamic study data files and the base case data files (peak and off peak cases) shall be provided by POSOCO (NLDC/RLDCs) and CTU every quarter."

7.3. **Analysis and Decision**

7.3.1. The suggestions SRPC and WRPC have been accepted.

7.3.2. With regard to suggestions of SJVN, it is clarified that it may seek system studies reports from RPC as required by it from time to time as a constituent of RPC.

7.3.3. Regulation 14 (3) (b) of the 2023 Grid Code Regulations have been modified as follows:
"(3) (b) carry out detailed system studies, once a year, for protection settings and advise modifications / changes, if any, to the CTU and to all users and STUs of their respective regions. The data required to carry out such studies shall be provided by RLDCs and CTU."

8. PROTECTION AUDIT PLAN (Regulation 15 (1))

8.1. **Commission's Proposal**

8.1.1. The Commission had proposed the following in Regulation 15 (1) of the Draft Regulations:
"15(1) - All users shall conduct internal audit of their protection systems annually, and any shortcomings identified shall be rectified and informed to their respective RPC."

8.2. **Comments have been received from SRPC, APP, MB Power and Power Grid**

8.2.1. **SRPC** has suggested adding "Audit report shall be shared with Respective RPC for 220 kV and above stations" at the end of the clause.

8.2.2. **APP** suggested that this activity be done once every three years, and both the IPPs and Transmission Utility should conduct an internal audit of their respective protection systems for Bay & Line annually and share their studies with each other for coordination purposes.

8.2.3. **MB Power** suggested that users (IPPs) connected with CTU conduct an annual joint audit of their protection systems for Bay and Line and correct any deficiencies with mutual consent. This will help ensure a more reliable 400kV grid system and prevent any relay coordination mismatches.

8.2.4. **Power Grid** suggested conducting an internal audit of their protection systems every two years instead of every year as there are large number of substations.

8.3. **Analysis and Decision**

8.3.1. The suggestions to increase the timeline to conduct an internal audit have not been accepted since a protection system audit is very important for grid security and must be conducted annually. Further, the suggestions for joint audit and sharing of studies may be taken by users at their level with mutual understanding.

8.3.2. The suggestions of SRPC have been accepted. Regulation 15 (1) of the 2023 Grid Code Regulations has been modified as follows:

"15 (1) All users shall conduct internal audit of their protection systems annually, and any shortcomings identified shall be rectified and informed to their respective RPC. The audit report along with action plan for rectification of deficiencies detected, if any, shall be shared with respective RPC for users connected at 220 kV and above (132 kV and above in NER)."

9. PROTECTION AUDIT PLAN (Regulation 15 (4))

9.1. **Commission's Proposal**

9.1.1. The Commission had proposed the following in Regulation 15 (4) of the Draft Regulations:

"(4) The third-party protection audit report shall contain information sought in format enclosed as Annexure–1. The protection audit reports, along with action plan for rectification of deficiencies detected, if any, shall be submitted to the respective RPC and RLDC within a month of submission of third party audit report."

9.2. **Comments have been received from HPSLDC, Power Grid and SLDC Odisha**

9.2.1. **HPSLDC** suggested adding SLDC with RPC, RLDC.

9.2.2. **Power Grid** suggested modifying the clause as follows

"… rectification of deficiencies detected, if any, shall be submitted to the respective RPC within two months of submission of the third-party detailed audit report."

Power Grid has commented that rectification action in line with recommendations can only be taken after the submission of a detailed protection audit report.

9.2.3. **SLDC Odisha** suggested that the timeline for completing compliance of the protection audit should also be informed by RPC.

9.3. **Analysis and Decision**

9.3.1. The suggestions of HPSLDC have been accepted.

9.3.2. The suggestion of Power Grid to submit report in two months is not accepted since follow up action on such a report is to be taken up.

9.3.3. With regard to the suggestion of SLDC Odisha for a timeline of completion of audit compliance, the Commission is of the view that the necessary compliance to third-party protection audit shall be followed up regularly in the respective RPC.

9.3.4. Regulation 15 (4) of the 2023 Grid Code Regulations has been modified as follows:

"15 (4) The third-party protection audit report shall contain information sought in the format enclosed as Annexure–1. The protection audit reports, along with action plan for rectification of deficiencies detected, if any, shall be submitted to the respective RPC and RLDC or SLDC, as the case may be, within a month of submission of third party audit report. The necessary compliance to such protection audit report shall be followed up regularly in the respective RPC."

10. PROTECTION AUDIT PLAN (Regulation 15 (5))

10.1. **Commission's Proposal**

10.1.1. The Commission had proposed the following in Regulation 15 (5) of the draft Regulations:

"15(5)- Annual audit plan for the next financial year shall be submitted by the users to their respective RPC by 31st October. The users shall adhere to the annual audit plan and report compliance of the same to their respective RPC."

10.2. **Comments have been received from TS Transco and Adani Power**

10.2.1. **TS TRANSCO** suggested modification as follows:

"Annual <u>third-party protection</u> audit …. adhere to the <u>annual third party audit plan</u> and report compliance to their respective RPC."

10.2.2. **Adani Power** suggested that this activity once in three years.

10.3. **Analysis and Decision**

10.3.1. The suggestions of TSTRANSCO are not accepted, since users need to submit an annual audit plan for internal audit also to RPC. The suggestions of Adani Power are also not accepted due to the importance of this activity to be carried out annually.

11. PROTECTION AUDIT PLAN (Regulation 15 (6))

11.1. **Commission's Proposal**

11.1.1. The Commission had proposed the following in Regulation 15 (6) of the Draft Regulations:

“15(6) Users shall submit the following protection performance indices of previous month to their respective RPC on monthly basis, which shall be reviewed by the RPC"

11.2. **Comments have been received from SRPC, APP, Tata Power, Power Grid, NHPC and POSOCO**

11.2.1. **SRPC** suggested modifying the clause as,

“Users shall submit the following protection performance indices of previous month <u>and for cumulative period for the FY</u> to their respective RPC on monthly basis for <u>220 kV and above system</u>, which shall be reviewed by the RPC.”

11.2.2. **APP** suggested that detailed protection indices based on reliability index, security index, dependability indices may be carried out only for particular relays that are operated on a real time basis as required by the system; OR be carried out on yearly basis for protection system elements which are connected to the Grid directly.

11.2.3. **Tata Power** has requested clarity on Indices in terms of what minimum level has to be calculated i.e. voltage and grid level.

11.2.4. **Power grid** suggested changing to quarterly in place of monthly as per present practice.

11.2.5. **NHPC** has commented that the basis of selection of no. of correct operations and other factors has not been deliberated and has suggested modification as follows:

“Users shall submit the following protection <u>indices</u> of previous month to their <u>respective RPC after discussion of such event at PCC meeting of respective RPC.</u>”

11.2.6. **POSOCO** suggested adding RLDC in addition to RPC for submission of indices.

11.3. **Analysis and Decision**

11.3.1. The suggestions of POSOCO and SRPC have been accepted. In light of comments of Tata Power, the voltage level has been inserted in the Regulation.

11.3.2. Regulation 15 (6) of the 2023 Grid Code Regulations has been modified as follows:

“15 (6) Users shall submit the following protection performance indices of previous month to their respective RPC and RLDC on monthly basis for 220 kV and above (132 kV and above in NER) system, which shall be reviewed by the RPC:”

11.3.3. The suggestions of APP to calculate indices for particular relays are not accepted since grid security issues may be caused by any relay, and all relays must conform to standards. However, any specific detailing may be finalised at the RPC level in consultation with RLDCs.

11.3.4. The suggestions of Powergrid and NHPC are not accepted. Timely submission of protection performance indices is crucial in order to develop an appropriate action plan and address any issues on a regular basis.

12. SYSTEM PROTECTION SCHEME (SPS) (Regulation 16 (2))

12.1. **Commission's Proposal**

12.1.1. The Commission had proposed the following in Regulation 16(2) of the Draft Regulations:

"16(2) - For the operational SPS, RPCs shall perform regular dynamic studies and mock testing for reviewing SPS parameters & functions, at least once in a year"

12.2. **Comments have been received from SRPC, SJVN Ltd., APP, WRPC and POSOCO**

12.2.1. **SRPC** has suggested modifying the clause,

"For the operational SPS, <u>RLDC/SLDCs</u> shall perform regular load flow and dynamic studies. <u>NLDC/RLDC/SLDC/Users shall coordinate Mock</u> testing for reviewing SPS parameters & functions, at least twice a year. <u>Mock Test will be coordinated in the RPC forum."</u>

12.2.2. **SJVN Ltd.** suggested that report of regular dynamic studies and mock testing for reviewing SPS parameters & functions be shared with concerned generators also.

12.2.3. **APP** suggested that the commercial impact of the Mock test of SPS needs to be addressed. Planning of the export schedule during a mock test of SPS also needs to be covered in the Grid Code.

12.2.4. **WRPC** suggested modifying the clause as follows:

"For the operational SPS, <u>RLDC in consultation with the RPC</u> shall perform regular dynamic studies and also carry out mock testing to review SPS parameters & functions, at least once a year. <u>RLDC to inform any short comings to respective RPC. The dynamic data for such studies shall be provided by CTU annually to RPC/RLDC</u>."

12.2.5. **POSOCO** suggested modifying the clause as follows:

"For the operational SPS, <u>RLDC/NLDC</u> shall perform regular dynamic studies and mock testing for reviewing SPS parameters & functions, at least once in a year…."

12.3. **Analysis and Decision**

12.3.1. In view of suggestions of SRPC, WRPC, and POSOCO, the Commission has modified the draft regulation for operational SPS wherein the studies and mock testing, as specified in the regulation, shall be carried out by RLDC/NLDC in consultation with the concerned RPC(s).

12.3.2. Some stakeholders suggested sharing the report of studies and mock testing, including any shortcomings, with the RPC and the concerned generators. In light of these suggestions, the Commission opines that the RLDC or NLDC should share the report of the studies and mock testing, including any shortcomings, with the respective RPC(s). The Commission believes that once information is received by the RPC, it may be disseminated to the concerned entities, including the respective generators.

12.3.3. Regulation 16 (2) of the 2023 Grid Code Regulations has been modified as follows:

"16 (2) For the operational SPS, RLDC or NLDC, as the case may be, in consultation with the concerned RPC(s) shall perform regular load flow and dynamic studies and mock testing for reviewing SPS parameters & functions, at least once in a year. RLDC or NLDC shall share the report of such studies and mock testing including any short comings to respective RPC(s). The data for such studies shall be provided by CTU to the concerned RPC, RLDC and NLDC."

13. SYSTEM PROTECTION SCHEME (SPS) (Regulation 16 (3))

13.1. Commission's Proposal

13.1.1. The Commission had proposed the following in Regulation 16(3) of the Draft Regulations,

"16(3) - The users and SLDCs shall report about the operation of SPS within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs."

13.2. Comments have been received from SRPC and POSOCO

13.2.1. **SRPC** suggested replacing "three days" with "24 Hrs".

13.2.2. **POSOCO** suggested modifying the clause as follows:

"The users and SLDCs shall report about the operation of SPS <u>immediately and detailed report shall be submitted</u> within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs."

POSOCO Suggested adding new clauses 16(4) as follows:

"(4) The performance of SPS shall be assessed as per the protection performance indices specified in these Regulations. In case the SPS fails to operate, the Users shall take corrective actions immediately and submit a detailed report on the corrective actions taken by them to RPC within a fortnight."

13.3. Analysis and Decision

13.3.1. In light of the suggestions of SRPC and POSOCO, Regulation 16 (3) of the 2023 Grid Code Regulations has been modified, and a new clause 16 (4) has been added by the Commission:

"16 (3) The users and SLDCs shall report about the operation of SPS immediately and detailed report shall be submitted within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs.

(4) The performance of SPS shall be assessed as per the protection performance indices specified in these Regulations. In case, the SPS fails to operate, the concerned User shall take corrective actions and submit a detailed report on the corrective actions taken to the concerned RPC within a fortnight."

14. RECORDING INSTRUMENTS (Regulation 17(1))

14.1. Commission's Proposal

14.1.1. The Commission had proposed the following in Regulation 17 (1) of the Draft Regulations,

"(1) All users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition."

14.2. **Comments have been received from POSOCO**

14.2.1. **POSOCO** suggested modifying as follows:

"All users/SLDCs shall keep the recording instruments (disturbance recorder, <u>data acquisition system, transient fault recorder, voice recorder</u> and event logger) in proper working condition."

14.3. **Analysis and Decision**

14.3.1. The recording instruments as disturbance recorder and event logger have been specified as an illustration. It is important to note that the recording instruments play a crucial role in monitoring and analysing the performance of grid-connected elements thereby helping to ensure the reliability and stability of the power system. The Commission is of the view that all recording instruments including those which are not mentioned under this regulation, should be kept in proper working condition.

15. RECORDING INSTRUMENTS (Regulation 17(2))

15.1. **Commission's Proposal**

15.1.1. The Commission had proposed the following in Regulation 17 (2) of the Draft Regulations,

"The disturbance recorders shall have time synchronization and a standard format for recording analogue and digital signals which shall be included in the guidelines issued by the respective RPCs."

15.2. **Comments have been received from POSOCO, Adani Power, APP, WRPC, Power Grid, and IEEMA Copper Alliance**

15.2.1. POSOCO suggested modifying clause (2) and inserting an additional clause (3) & (4) as follows,

"(2) The disturbance recorders shall have time synchronization and shall be configured for recording analogue and digital signals as per guidelines issued by the respective RPCs.

(3) SOE indicating Protection signal and Breaker Opening/Closing signal should be integrated with SCADA/WAMS at RLDC/SLDC/REMC for

a. 220kV/230kV and above SS (132 kV& above for NER)

b. Renewable plants at 33 kV and above.

c. 33kV feeders connected to 220/33 kV or 132/33 kV substation having defense schemes (AUFLS, UVLS Df/Dt, SPS, ADMS, Islanding).

(4) Recording instruments (disturbance recorder and event logger) shall have the facility of automatic downloads."

15.2.2. **Adani Power** Suggested that while most of the signals can be standardized, few of them can be application / product specific.

15.2.3. **APP** suggested adding the following provision to this clause,

"Provision of disturbance and event recording may be provided by either of the following methods:

i) Separate disturbance and event recorder

ii) As in-built feature of recording the disturbances and events on central PC, which is used for parametrization of numerical relays.

iii) As in-built feature of numerical relays to record disturbances and events."

APP has also commented that while most of the signals can be standardized, a few of them may be application / product specific. This may be appropriately clarified.

15.2.4. **WRPC** has commented that the DRs time synchronization can be verified based on the signatures seen in the PMU data and event loggers of SCADA.

WRPC has suggested inserting the following at the end of the clause:

"The time synchronization of the DRs shall be corroborated with the PMU data/SCADA event loggers etc. by the respective RLDCs and the list of DRs which are non-compliant shall be placed before the Protection sub-Committee."

15.2.5. **Power Grid** suggested modifying the clause as follows:

"The disturbance recorders shall have time synchronization and <u>include analogue & digital signals as specified by the respective RPCs. The sequence and naming of the signals may be decided by respective utilities</u>*."*

15.3. Analysis and Decision

15.3.1. The suggestions of stakeholders are about detailing aspects that may be included in guidelines formulated at RPC level.

15.3.2. Commission has added new regulation 17 (3) to the 2023 Grid Code Regulations:

"17 (3) The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers by the respective RLDC. Disturbance recorders which are non- compliant shall be listed out for discussion at RPC."

CHAPTER 5 - COMMISSIONING AND COMMERCIAL OPERATION CODE

1. General (Regulation 18)

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation (18) of the Draft Regulations:

"This chapter covers aspects related to (i) drawl of startup power from and injection of infirm power into the grid, (ii) trial run operation (iii) documents and tests required to be furnished before declaration of COD, (iv) requirements for declaration of COD."

1.2. **Comment has been received from NHPC.**

1.2.1. **NHPC** has commented that as per the Tariff Regulation 2019-24, the 'Useful Life' in relation to a unit of a Hydro generating station, including pumped storage hydro generating stations is 40 years. The generating company may undertake Renovation and Modernization (R&M) of the generating station or unit thereof for the purpose of extension of life beyond the originally recognized useful life. In this regard, NHPC has requested clarification on whether a Trial Run operation and Declaration of Commercial Operation would be required for generating units after the completion of R&M works for generating units.

1.3. **Analysis and Decision**

1.3.1. Keeping in view the suggestions of NHPC, the relevant provision has been incorporated in Regulation 21(4) of the Grid Code Regulations 2023 as follows:

"(4) A generating station shall be required to undergo a trial run in accordance with Regulation 22 of these regulations after completion of Renovation and Modernization for extension of useful life of the project as per the Tariff Regulations."

2. DRAWAL OF START UP POWER AND INJECTION OF INFIRM POWER (Regulation 19 (2))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation (19) (2) of the Draft Regulations:

"19(2) The period for which such interchange shall be allowed shall be as follows: -
(a) Drawal of start-up power shall not exceed 15 months prior to the expected date of first synchronization and 6 months after the date of first synchronization; and
(b) Injection of infirm power shall not exceed six months from the date of first synchronization"

2.2. **Comments have been received from Tata Power and POSOCO.**

2.2.1. Tata **Power** has requested to extend the duration for the drawal of start-up power and injection of infirm power after the date of the first synchronization, from 6 months to 12 months.

2.2.2. **POSOCO** commented that in an RE station with only part capacity commissioned, the segregation of firm and infirm injection of power becomes difficult.

2.3. **Analysis and Decision**

2.3.1. The suggestion of Tata Power has been accepted, and the regulation has been modified as follows:

"19 (2) The period for which such inter-change shall be allowed shall be as follows: -
(a) Drawal of start-up power shall not exceed 15 months prior to the expected date of first synchronization and one year after the date of first synchronization; and
(b) Injection of infirm power shall not exceed one year from the date of first synchronization."

2.3.2. With regard to suggestions of POSOCO for segregation of firm and infirm injection in stations, the provision has been added as Regulation 19(8) of the Grid Code Regulations 2023 as follows:

"(8) In the case of multiple generating units of the same generating station or multiple generating stations owned by different entities connected at a common ISTS interface point, RLDC shall ensure segregation of firm power from generating units that have achieved COD from power injected or drawn by generating units which have not achieved COD through appropriate accounting of energy."

3. DRAWAL OF START UP POWER AND INJECTION OF INFIRM POWER (Regulation 19 (3))

3.1. **Commission's Proposal**

3.1.1. The Commission had proposed the following in Regulation (19) (3) of the Draft Regulations:

"(3) Notwithstanding the provisions of clause (2) of this Regulation, the Commission may in exceptional circumstances, allow extension of the period for inter-change of power beyond the stipulated period on an application made by the generating station at least two months in advance of completion of the stipulated period."

3.2. **Comments have been received from Tata Power Limited and POSOCO.**

3.2.1. Torrent **Power Limited** has suggested removing the words "in exceptional circumstances" from the clause.

3.2.2. **POSOCO** has proposed that any drawal of start-up power or injection of infirm power should be scheduled by the generating station using RTM.

3.3. **Analysis and Decision**

3.3.1. In respect to the suggestion put forth by Torrent Power, the regulation has been modified and the term "in exceptional circumstances" has been removed.

3.3.2. The suggestion of POSOCO that drawal/injection of infirm power can only occur through RTM is not accepted and the generating stations have the flexibility to choose between entering into a contract, or through DSM for the drawal of start-up power or injection of infirm power, keeping in view the nature of such drawal and injection.

4. DRAWAL OF START UP POWER AND INJECTION OF INFIRM POWER (Regulation 19 (4))

4.1. **Commission's Proposal**

4.1.1. The Commission had proposed the following in Regulation (19) (4) of the Draft Regulations:

"19(4) Drawal of start-up power shall be subject to payment of transmission charges as per Sharing Regulations"

4.2. **Comments have been received from SRPC and PCKL.**

4.2.1. SRPC has suggested modifying the clause by inserting "/injection of infirm power", as per draft Sharing Regulations (1st amendment).

4.2.2. **PCKL** has suggested including "payment of deviation charges" in the clause.

4.3. **Analysis and Decision**

4.3.1. As per regulation 13 (11) of the CERC (Sharing of Inter-State Transmission Charges and Losses) (First Amendment) Regulations, 2023, transmission deviation charges shall not be levied for injecting infirm power prior to COD of a generating station. Therefore, the provision as proposed in the Draft Regulations has been retained.

4.3.2. The suggestion of PCKL has been accepted, and accordingly, a new clause has been added,

"(5) The charges for deviation for drawal of start-up power or for injection of infirm power shall be as per DSM regulations"

5. DRAWAL OF START UP POWER AND INJECTION OF INFIRM POWER (Regulation 19 (6))

5.1. **Commission's Proposal**

5.1.1. The Commission had proposed the following in Regulation (19) (6) of the Draft Regulations:

"(6) The onus of proving that the interchange of infirm power from the unit(s) of the generating station is for the purpose of pre-commissioning activities, testing and commissioning, shall rest with the generating station and the concerned RLDC shall seek such information on each occasion of interchange of power before COD. For this, the generating station shall furnish to the concerned RLDC relevant details of the specific commissioning activity, testing and full load testing, its duration and intended period of interchange, etc."

5.2. **Comments have been received from Torrent Power Limited and POSOCO**

5.2.1. **Torrent Power Limited** suggested removing the words "on each occasion" from the clause.

5.2.2. **POSOCO** has suggested that the generating station must submit a tentative day-ahead schedule for infirm power injection to RLDC.

5.3. **Analysis and Decision**

5.3.1. The Commission has not accepted the suggestion of Torrent power as RLDC will seek information regarding interchange of power before COD, so as to maintain Grid stability. Also, there should not be any interchange of infirm power except the conditions as stipulated in the regulation. The suggestion of POSOCO to include a tentative day ahead plan for injection, would help POSOCO manage such drawals/injections has been accepted.

5.3.2. The regulation has been modified as follows:

“19 (7) The onus of proving that the interchange of infirm power from the unit(s) of the generating station is for the purpose of pre-commissioning activities, testing and commissioning, shall rest with the generating station, and the concerned RLDC shall seek such information on each occasion of the interchange of power before COD. For this, the generating station shall furnish to the concerned RLDC relevant details, such as those relating to the specific commissioning activity, testing, and full load testing, its duration and the intended period of interchange. <u>The generating station shall submit a tentative plan for the quantum and time of injection of infirm power on day ahead basis to the respective RLDC</u>.”

6. DRAWAL OF START UP POWER AND INJECTION OF INFIRM POWER (Regulation 19 (7))

6.1. **Commission’s Proposal**

6.1.1. The Commission had proposed the following in Regulation (19) (7) of the Draft Regulations:

“19(7) RLDC shall stop the drawl of the start-up Power in the following events:

(a) <u>In</u> case, it is established that the start-up power has been used by the generating station for construction activity;

(b) In case of default in payment of monthly transmission charges.”

6.2. **Comments have been received from SRPC, PCKL, POSOCO, Torrent Power, Sterlite and BALCO.**

6.2.1. **SRPC, PCKL, and POSOCO** have suggested adding DSM charges, RLDC Fees and Charges along with other charges.

6.2.2. **Torrent Power Limited** suggested that SLDC shall be added with RLDC.

6.2.3. **Sterlite** and **BALCO** have requested to make provision for allowing Discoms to provide connection to Generators connected through ISTS grid for drawl of Start-up Power.

6.3. **Analysis and Decision**

6.3.1. The suggestion of Torrent Power is not accepted as the respective clauses may be covered in the State Grid Code.

6.3.2. No changes are required to consider the suggestion of Sterlite and BALCO as the generating station can draw start power through a separate line connecting to Discom or through ISTS, as is the current practice .

6.3.3. The suggestions of SRPC, PCKL and POSOCO have been accepted and the regulation has been modified as follows.

“19 (9) RLDC shall stop the drawl of the start-up Power in the following events:

(a) In case, it is established that the start-up power has been used by the generating station for construction activity;

(b) <u>In the case of default in payment of monthly transmission charges, charges under RLDC Fees and </u>Charges<u> Regulations and deviation charges under the DSM Regulations</u>."

7. DATA TO BE FURNISHED PRIOR TO NOTICE OF TRIAL RUN (Regulation 20 (1))

7.1. Commission's Proposal

7.1.1. The Commission had proposed the following in Regulation (20) (1) of the Draft Regulations:

"20(1) The following details, as applicable, shall be furnished by each regional entity generating station prior to notice of trial run:"

7.2. Comments have been received from SRPC, KSEB, Prayas EG, Sembcorp, Sterlite, BALCO and POSOCO.

7.2.1. SRPC suggested replacing "ex-bus" mentioned in the Minimum turndown level parameter with "rated", in line with the draft CEA (Flexible operation of thermal power plants) Regulations, 2022.

7.2.2. **KSEB** suggested adding a new parameter, "MCR" in the clause.

7.2.3. **Sembcorp** suggested including a separate table for wind and solar power plants.

7.2.4. **Sterlite** and **BALCO** have requested modifying the format as per the generation source to make it more inclusive and align with changing technology and configurations.

7.2.5. **POSOCO** suggested replacing "MWh" mentioned in the Installed Capacity of generating station parameter with "MVA".

POSOCO has also suggested adding another column on applicability to different types of generating units.

7.2.6. **Prayas EG** requested clarification, as there is a need to periodically re-check these important parameters. Prayas EG has enquired whether there is any periodic re-check included in some other code like the Monitoring & Compliance code.

7.3. Analysis and Decision

7.3.1. The suggestion of SRPC and KSEB has been accepted by the Commission. The Generating entity shall furnish a Minimum turn down level in terms of % of MCR and MW (ex-bus) basis.

7.3.2. The suggestion of Sterlite and BALCO to segregate the table generation source wise is not required in the Grid Code and the same shall be incorporated by RLDC in its Portal.

7.3.3. The Commission clarifies that the generating station submits parameters while declaring DC on a day ahead basis as per provisions of Chapter – 7 of the Grid Code, while for certain parameters a re-check procedure has been included in the Grid Code under Periodic testing (Regulation 40 of the 2023 Grid Code).

8. NOTICE OF TRIAL RUN (Regulation 21 (1))

8.1. **Commission's Proposal**

8.1.1. The Commission had proposed the following in Regulation (21) (1) of the Draft Regulations:

"21(1) - The generating company proposing its generating station or a unit thereof for trial run or repeat of *trial run shall give a notice of not less than seven (7) days to the concerned RLDC and the beneficiaries of the generating stations wherever identified. The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC"*

8.2. **Comments have been received from SECI, NHPC, NTPC, PCKL and Torrent Power.**

8.2.1. **SECI** suggested including the intermediary procurers to the beneficiaries for giving notice for a trial run to the beneficiaries.

8.2.2. **NHPC** suggested reducing repeat trial runs within three days in place of seven days.

8.2.3. **NTPC** has suggested that in the case of RE generating stations, the power sale is normally to a single beneficiary and to avoid wastage of natural resource, the requirement of giving 7 days' notice in case of RE generating stations may be reduced to 3 days' notice.

8.2.4. **PCKL** suggested that the information regarding trial run shall be informed to the respective SLDC and beneficiaries of the generating stations.

8.2.5. **Torrent Power Limited** has suggested replacing the RLDC with the generating station as the authority responsible for determining the commencement of the trial run on the requested date.

8.3. **Analysis and Decision**

8.3.1. The suggestion of SECI has been accepted by the Commission.

8.3.2. The suggestions of NHPC and NTPC are not accepted, as it is necessary to serve prior notice of the trial run to the relevant beneficiaries and intermediary procurers, enabling them time to witness the trial run. The timeline has been retained as 7 days.

8.3.3. The generating station under control area of SLDC shall be governed as per the State Grid Code and hence SLDC is not inserted.

8.3.4. Considering the suggestion of Torrent Power, Regulation 21(1) has been modified and a new clause 21(3) has been added as follows:

"21(3) The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC."

9. NOTICE OF TRIAL RUN (Regulation 21 (2))

9.1. **Commission's Proposal**

9.1.1. The Commission had proposed the following in Regulation (21) (2) of the Draft Regulations, *"(2) In case the repeat trial run is to take place within twenty-four (24) hours of the failed trial run, fresh notice shall not be required."*

9.2. **Comments have been received from DVC and NTPC.**

9.2.1. **DVC** and **NTPC** have suggested extending twenty-four (24) hours to Seventy-Two (72) hours.

9.3. **Analysis and Decision**

9.3.1. Considering the suggestion of DVC and NTPC, the timeline has been extended from 24 hours to 48 hours, and the regulation has been modified as follows:

"Provided that in case the repeat trial run is to take place within forty-eight (48) hours of the failed trial run, fresh notice shall not be required."

10. NOTICE OF TRIAL RUN (Regulation 21 (3))

10.1. **Commission's Proposal**

10.1.1. The Commission had proposed the following in Regulation (21) (3) of the Draft Regulations:

"(3)The transmission licensee proposing its transmission system or an element thereof for trial run shall give a notice of not less than seven days to the concerned RLDC and CTU."

10.2. **Comments have been received from POSOCO, GRIDCO, and Power Grid.**

10.2.1. **POSOCO** has requested for a clarification on, what will be the notice period for repeat trial operation, if the transmission licensee fails. Notice may be marked to all the beneficiaries as well.

10.2.2. **GRIDCO** has suggested that notice should also be given to the concerned Stakeholders.

10.2.3. **Power Grid** has suggested removing this clause as standard procedures already exist for required compliance, declaration, and information in prescribed formats which are submitted to the concerned RLDC before the trial run for the relevant transmission elements.

10.3. **Analysis and Decision**

10.3.1. In respect to the suggestion of POSOCO, the Commission is of the view that if transmission licensee fails during the trial run, it should follow the same procedure as that of the generating station.

10.3.2. The Commission accepts the suggestions of GRIDCO and POSOCO, which include adding distribution licensees and owners of interconnecting systems to the list of entities to whom the transmission licensee should provide notice.

10.3.3. The suggestion of Power Grid has not been accepted, as it is crucial to ensure that notice of the trial run is provided and that the concerned stakeholders are given a sufficient amount of time to observe the trial run.

10.3.4. The regulation has been modified as follows

"(2) The transmission licensee proposing its transmission system or an element thereof for trial run shall give a notice of not less than seven days to the concerned RLDC, CTU, distribution licensees of the region and the owner of the inter-connecting system."

11. TRIAL RUN OF GENERATING UNIT (Regulation 22 (1) (b))

11.1. Commission's Proposal

11.1.1. The Commission had proposed the following in Regulation (22) (1) (b) of the Draft Regulations:

"(b) Where on the basis of the trial run, a thermal generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company has the option to de-rate the capacity of the generating unit or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall be not more than 95% of the demonstrated capacity, to cater for primary response."

11.2. Comments have been received from SRPC.

11.2.1. **SRPC** has suggested removing the de-rate option for the generating company from the clause. Primary response is to be demonstrated only for 5 minutes, while capacity has to be demonstrated for 72 hrs. If Primary Response is tested for 5 mins at de-rated /rated capacity, there would be no need to further de-rate the capacity on a sustained basis.

11.3. Analysis and Decision

11.3.1. The Commission is of the view that de-rating shall be considered if the generating station is unable to demonstrate its MCR capacity. If the generating station fails to meet the MCR, it must keep the margins to cater to primary response while finalising the de-rated capacity.

11.3.2. The provision as proposed in the Draft Regulations has been retained.

12. TRIAL RUN OF GENERATING UNIT (Regulation 22 (2) (a) & (b))

12.1. Commission's Proposal

12.1.1. The Commission had proposed the following in Regulation (22) (2) (a) & (b) of the Draft Regulations:

"(2) Trial Run of Hydro Generating Unit shall be carried out in accordance with following provisions:

(a) A hydro generating unit shall be in continuous operation at MCR for twelve (12) hours:

Provided that-

(i) any interruption shall call for a repeat of trial run;

(ii)partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR;

(iii) if it is not possible to demonstrate the MCR due to insufficient reservoir or pond level or insufficient inflow, COD may be declared, subject to the condition that the same shall be demonstrated immediately when sufficient water is available after COD.

(b)Where on the basis of the trial run, a hydro generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-

rate the unit capacity, the de-rated capacity in such cases shall be not more than 90% of the demonstrated capacity to cater for primary response"

12.2. **Comments have been received from KSEBL, Directorate of Energy (HP), NHPC, POSOCO, and PCKL.**

12.2.1. **KSEBL** suggested trial run at MCR for seventy two (72) hours for getting better understanding of bearing temperature rise, generator/field wing/transformer temperature rise and machine vibration.

12.2.2. **Directorate of Energy, HP State Government** commented that the reliability and safety of the project could not be assessed in case the project is not operated at its full load capacity and with over loading capacity. It should be mandatory to conduct the trial run with full load or MCR, when sufficient water available or within one year, whichever is earlier, with respect to COD declared by generating station.

12.2.3. **NHPC** has suggested retaining the provision of short interruption during the trial run operation of hydro units as per the 2010 Grid Code. It has also been suggested that partial loading may be allowed with the condition that the average load during the duration of the trial run, excluding the period of interruption and partial loading but including the corresponding extended period shall not be less than MCR.

12.2.4. **PCKL** commented that the Trial run operation of Small hydro generating station may be specified.

12.2.5. **POSOCO** has commented that it should be clarified whether the de-rated capacity would be effective from the date of commercial operation.

12.3. **Analysis and Decision**

12.3.1. The timeline for hydro generating units is not extended from 12 hours since a hydro generating stations have a limited number of moving parts as compared to a thermal generating unit, and 12 hours is a sufficient timeline to demonstrate the capability. Further, keeping in view the water availability, it is observed that water to demonstrate a full load run for 72 hours may not be feasible.

12.3.2. In respect to the suggestion of the Directorate of Energy, HP, it is clarified that water levels are assessed over a period of 100 years and it may be possible that sufficient water levels are not available even within one year of achieving COD. Hence, it is provided that if sufficient water is not available, the rated capacity shall be demonstrated immediately when sufficient water is available, failing which the capacity of the hydro generating station will be de-rated.

12.3.3. The suggestion of NHPC has been accepted and the period of interruption has been provided for as per the 2010 Grid Code.

12.3.4. In respect to the suggestion of PCKL, it is clarified that same clause may be referred for trial run of small hydro generating stations.

12.3.5. In respect to the suggestion of POSOCO, the Commission also clarifies that the de-rated capacity will be effective from the date of commercial operation.

12.3.6. Regulation 22 (2) (a) of the 2023 Grid Code Regulations has been modified as follows:

"(2) Trial Run of Hydro Generating Unit shall be carried out in accordance with the following provisions:

(a) A hydro generating unit shall be in continuous operation at MCR for twelve (12) hours: Provided that-
(i) short interruption or load reduction shall be permissible with a corresponding increase in duration of the test;
(ii) interruption or partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period;
(iii) cumulative interruption of more than four (4) hours shall call for a repeat of trial run;
(iv) if it is not possible to demonstrate the MCR due to insufficient reservoir or pond level or insufficient inflow, COD may be declared, subject to the condition that the same shall be demonstrated immediately when sufficient water is available after COD:
Provided that if such a generating station is not able to demonstrate the MCR when sufficient water is available, the generating company shall de-rate the capacity in terms of sub-clause (b) of this clause, and such de-rating shall be effective from COD."

13. TRIAL RUN OF GENERATING UNIT (Regulation 22 (3) (a) & (b))

13.1. Commission's Proposal

13.1.1. The Commission had proposed the following in Regulation (22) (3) (a) & (b) of the Draft Regulations:

"(3) Trial Run of Wind / Solar / Storage / Hybrid Generating Station

(a) Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than the period between sunrise to sunset in a single day with the requisite metering system, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and its performance shall be corroborated with the solar irradiation recorded at site during the day and plant design parameters. For the trial run, a declaration shall be given by the generating company that no panel has been replaced or added or taken out or design of the plant has been altered:
Provided that:
(i) the output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run;
(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient solar irradiation is available after COD.

(b) Successful trial run of a wind turbine(s) aggregating to 50 MW and above shall mean flow of power and communication signal for a period of not less than four (4) hours during periods of wind availability with the requisite metering system, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and corroborate its performance with the wind speed recorded at site(s) during the day and plant design parameters:
Provided that-
(i) the output below the corroborated performance level with the wind speed of the day shall call for repeat of the trial run;
(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient wind velocity, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient wind velocity is available after COD."

13.2. **Comments have been received from POSOCO, UPSLDC, SECI, BALCO,**

Sterlite, Adani Power, AGEL, O2 Power, APP, Hero Future Energy, ReNew, Greenko Group, NSF, Enel, Sembcorp, NTPC, IWPA, O2 Power and WIPPA

13.2.1. **POSOCO** has suggested including the Power Plant Controller in trial run, clarification regarding the treatment of capacities below 50 MW and maximum timeline to demonstrate MCR. POSOCO has also requested clarification on whether the flow of power and communication signals for a period of not less than 4 Hours to be considered as cumulative or continuous.

13.2.2. **UPSLDC** suggested that the maximum time allowed for demonstration of peak capacity may be included in the Grid Code.

13.2.3. **SECI** suggested adding temperature with solar irradiation and alternatively, minimum Performance Ration (PR) may be mentioned which is an international standard for plant performance and can refer to the relevant IEC/IS code (IEC 61724).

13.2.4. **BALCO**, **Sterlite** suggested replacing 50 MW with 25MW in the clause.

13.2.5. **Adani Power, AGEL, O2 Power, APP, Hero Future Energy, ReNew, Greenko Group, National Solar Federation,** and **ENEL** have suggested that the declaration that no panel has been replaced or added or taken out or design of the plant has been altered is in contravention with MNRE advisory and accordingly may be deleted. MNRE, in its advisory/clarification dated 05.11.2019 w.r.t DC capacity of Solar PV power plants, has advised that the design and installation of solar capacity on the DC side should be left to the generator/developer. Also, as per law, the setting up of generation capacity is an unlicensed activity, and therefore any person is entitled to set up any capacity which it desires to set up.

13.2.6. **Sembcorp** suggested that this provision should not be applicable for variable RE sources. It is requested to delete the proviso (ii) of both a and b of Regulation 22.

13.2.7. **NTPC** suggested that the trial run may be for 4 continuous hours between sunrise to sunset. NTPC has commented that a provision may also be provided for successful trial run for partial capacity out of the total intended capacity for trial run.

13.2.8. **IWPA** has suggested removing the stipulated minimum of four hours of trial run, and the date of synchronisation with the grid duly witnessed by the designated agency may be considered as the date for COD.

13.2.9. **O2 Power, Sembcorp, and WIPPA** suggested removing this clause and requested that the COD of Wind Project be continued based on existing practices.

13.3. **Analysis and Decision**

13.3.1. The suggestions to remove the clause have been rejected. The rationale for the introduction of the trial run and COD for RE generating units was provided in the Explanatory Memorandum as follows:

"(a) It is necessary to harmonize the criteria for commercial operation date declaration across all generators to maintain consistency and clarity. It is proposed to allow part commissioning for a capacity of 50 MW for both wind and solar generators. This may also benefit the consumers since it will help meet the adequacy targets and RPO obligations.

It is observed that different PPAs had different provisions for the declaration of commercial operation. Once a generating unit is required to be integrated into the Grid, the trial run for the capacity with uniform criteria is required. Accordingly, the clause has been retained.

13.3.2. Considering the suggestion of POSOCO, PPC has been included in the trial run, capacities below 50 MW have been included in the modified regulations and the maximum timeline to demonstrate MCR as within one year of COD has been provided for in the 2023 Grid Code. Further 'cumulative' has been inserted in the clause.

13.3.3. Considering suggestions of SECI, corroboration with temperature has been inserted in the clause.

13.3.4. The Commission clarifies that the minimum capacity required for a trial run is 50 MW or less as allowed under minimum capacity for Connectivity at ISTS under the GNA Regulations.

13.3.5. Suggestions of stakeholders to remove the declaration about change in panel/plant design have been accepted and the clause has been deleted.

13.3.6. In respect to the suggestion of NTPC, the Commission clarifies that for Solar power plants, a cumulative period of 4 hours needs to be considered for the flow of power & communication signal, and for Wind Power Plants, a continuous period of 4 hours needs to be considered.

13.3.7. The regulation has been modified as follows:

"(3) Trial Run of Wind / Solar / ESS / Hybrid Generating Station

(a) Trial run of the solar inverter unit(s) shall be performed for a minimum capacity aggregating to 50 MW:

Provided that in the case of a project having a capacity of more than 50 MW, the trial run for the balance capacity shall be performed in a maximum of four instalments with a minimum capacity of 5 MW:

Provided further that the trial run for solar inverter unit(s) aggregating to less than 50 MW for entities covered under clause (e) of Regulation 4.1 of the GNA Regulations, shall be allowed for the capacity for which Connectivity has been granted to such entity.

(b) Successful trial run of a solar inverter unit(s) covered under sub-clause (a) of this clause shall mean the flow of power and communication signal for not less than four (4) hours on a cumulative basis between sunrise and sunset in a single day with the requisite metering system, power plant controller, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and shall corroborate its performance with the temperature and solar irradiation recorded at site during the day and plant design parameters:

Provided that:

(i) the output below the corroborated performance level with the solar irradiation of the day shall call for a repeat of the trial run;

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, COD may be declared subject to the condition that the same shall be

demonstrated immediately when sufficient solar irradiation is available after COD, within one year from the date of COD:

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient solar irradiation is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (h) of clause (3) of this Regulation.

…….

"(d) Successful trial run of a wind turbine(s) covered under sub-clause (c) of this clause shall mean the flow of power and communication signal for a period of not less than continuous four (4) hours during periods of wind availability with the requisite metering system, power plant controller, telemetry and protection system in service.

The generating company shall record the output of the unit(s) during the trial run and corroborate its performance with the wind speed recorded at the site(s) during the day and plant design parameters:

Provided that-

(i) the output below the corroborated performance level with the wind speed of the day shall call for a repeat of the trial run;

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient wind velocity, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient wind velocity is available after COD, within one year from the date of COD:

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient wind velocity is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (h) of clause (3) this Regulation."

14. TRIAL RUN OF GENERATING UNIT (Regulation 22 (3) (f))

14.1. Commission's Proposal

14.1.1. The Commission had proposed the following in Regulation (22) (3) (f) of the Draft Regulations:

"(f) Where on the basis of the trial run, solar / wind / storage / hybrid generating station fails to demonstrate its rated capacity, the generating company shall have the option to either to go for repeat trial run or de-rate the capacity subject to a minimum aggregated de-rated capacity of 50 MW. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall be not more than 90% of the demonstrated capacity to cater for primary response."

14.2. Comments have been received from SRPC, Sembcorp, POSOCO

14.2.1. **SRPC** has suggested removing the clause relating to the de-rating of the capacity. SRPC has also suggested that the applicable generating stations shall demonstrate Primary Mandated response as per CEA Connectivity Regulations/IEGC Provisions.

14.2.2. **Sembcorp** suggested that this provision should not be applicable for variable RE sources. It is requested to delete the clause 3(f) of Regulation 22.

14.2.3. **POSOCO** has suggested that de-rated capacity is effective from the date of CoD.

14.3. **Analysis and Decision**

14.3.1. In respect to the suggestion of SRPC, the Commission clarifies that demonstration of capacity is a must since the capacity which is claimed to be declared COD must be established.

14.3.2. The suggestion of POSOCO has been accepted, and regulation has been modified as follows,

“(h) Where, on the basis of the trial run, solar / wind / storage / hybrid generating station fails to demonstrate its rated capacity, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity subject to a minimum aggregated de-rated capacity of 50 MW or 5 MW, as the case may be.”

14.3.3. A new clause has been added as Regulation 22(3)(i) as follows:

“(i) Notwithstanding the provisions contained in this Regulation, where Power purchase Agreement provides for a specific capacity that can be declared COD, trial run shall be allowed for such capacity in terms of such Power purchase agreement.”

15. TRIAL RUN OF INTER-STATE TRANSMISSION SYSTEM (Regulation 23 (1))

15.1. **Commission’s Proposal**

15.1.1. The Commission had proposed the following in Regulation (23) (1) of the Draft Regulations,

“(1) Trial run of a transmission system or an element thereof shall mean successful energisation of the transmission system or the element thereof at its nominal system voltage through interconnection with the grid for continuous twenty-four (24) hours flow of power and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system”

15.2. **Comments have been received from Adani Power, APP, DVC, HPSLDC, GRIDCO and POSOCO.**

15.2.1. **Adani Power and APP** have commented that the provision is to be kept for anti-theft charging, wherein no power flows in the system.

15.2.2. **DVC** has commented that the trial-run certificate with respect to all the elements (including Bays) of voltage level 220kV and below is being issued by SLDC. However, for tie lines, intimation of successful trial operation is forwarded to ERLDC.

15.2.3. **HPSLDC** requested clarification on, what is the treatment for the transmission system or an element thereof connected with a Run-of-River (RoR) hydro station where the availability of flow of water is uncertain or in case of RE, where solar generation is not available at night.

15.2.4. **GRIDCO** suggested that maintaining nominal system voltage 24 hours continuously for the transmission system or element thereof may not be possible always. The same may be modified in line with Clause No.3 (b) (Standards for Operation and Maintenance of Transmission Lines) of the Central Electricity Authority (Grid Standards) Regulations, 2010, specifying the limits for variation in nominal system voltage.

15.2.5. **POSOCO** has commented that in case, such a transmission line is connected to a hydro station where inflow is not available or in case of RE, where solar generation is not available at night, and flow can't be possible for continuous 24 hrs.

15.3. **Analysis and Decision**

15.3.1. The suggestions of Adani Power and APP have been accepted by the Commission.

15.3.2. With respect to the suggestion of DVC, the Commission clarifies that the trial run will be carried out by the respective Load Despatch Centres, as applicable.

15.3.3. In respect to the suggestion of HPSLDC and POSOCO about periods of no power generation, the Commission clarifies that the trial run necessitates the flow of power, but not necessarily the rated flow of power. The timing of the trial run shall be determined by the RLDC, taking into consideration various conditions.

15.3.4. The suggestion of GRIDCO has been considered. The Commission clarifies that voltage variations are allowed as per the CEA Standards.

15.3.5. The regulation has been modified as follows,

"(1) Trial run of a transmission system or an element thereof shall mean successful energisation of the transmission system or the element thereof at its nominal system voltage through interconnection with the grid for a continuous twenty-four (24) hours flow of power and communication signal from the sending end to the receiving end and with the requisite metering system, telemetry and protection system:

Provided that under exceptional circumstances and with the prior approval of CEA, a transmission element can be energized at lower nominal system voltage level.

<u>Provided further that the RLDC may allow anti-theft charging where the transmission line is not carrying any power</u>."

16. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (1))

16.1. **Commission's Proposal**

16.1.1. The Commission had proposed the following in Regulation (24) (1) of the Draft Regulations:

"(1)Notwithstanding the requirements in other standards, codes and contracts, for ensuring grid security, the tests as specified in the following clauses shall be scheduled and carried out in coordination with NLDC and the concerned RLDC by the generating company or the transmission licensee, as the case may be, and relevant reports and other documents as specified shall be submitted to NLDC and the concerned RLDC before a certificate of successful trial run is issued to such generating company or the transmission licensee, as the case may be."

16.2. **Comment has been received from POSOCO.**

16.2.1. POSOCO suggested that the specified tests should be carried out before being allowed to proceed for the trial run for declaration of commercial operation.

16.3. **Analysis and Decision**

16.3.1. It is clarified that certain tests are conducted during the trial run operation. However, it is mandatory to complete all tests and submit the required documents prior to the issuance of the trial run certificate, thereby fulfilling POSOCO's requirements.

16.3.2. The provision as proposed in the Draft Regulations has been retained.

17. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (2) (a))

17.1. **Commission's Proposal**

17.1.1. The Commission had proposed the following in Regulation 24 (2) (a) of the Draft Regulations

"(a) The generating company shall submit OEM documents for (i) performance characteristic curve for boiler, turbine and generator, (ii) starting time of unit in cold, warm and hot conditions, (iii) design ramp rate;"

17.2. **Comments have been received from NTPC.**

17.2.1. **NTPC** suggested that, for projects with different OEMs for SG and TG, separate documents for each shall be submitted and accepted; and the turbine performance characteristic curve should also be included in the list of OEM documents.

17.3. **Analysis and Decision**

17.3.1. Considering the NTPC suggestion, the regulation has been modified as follows,

"(a) The generating company shall submit the following OEM documents, namely (i) start up curve for boiler and turbine including starting time of unit in cold, warm and hot conditions, (ii) capability curve of generator, (iii) design ramp rate of boiler and turbine."

18. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (2) (b) (i))

18.1. **Commission's Proposal**

18.1.1. The Commission had proposed the following in Regulation 24 (2) (b) (i) of the Draft Regulations:

"(2) Documents and Test Reports Prior to Declaration of Commercial Operation

(b) The following tests shall be performed:

(i) Operation at a control load of fifty (50) percent of MCR as per the CEA Technical Standards for Construction for a sustained period of four (4) hours."

18.2. **Comments have been received from SRPC, APP and NTPC.**

18.2.1. **SRPC, APP, and NTPC** suggested that for supercritical units, the operation should be tested at a control load of 55% in order to ensure the stability of the unit.

18.3. **Analysis and Decision**

18.3.1. The suggestion of SRPC, APP, and NTPC has been accepted and the testing has been modified to be done at 55% of load. The regulation has been modified as follows:

"(b) The following tests shall be performed:

(i) Operation at a load of fifty-five (55) percent of MCR as per the CEA Technical Standards for Construction for a sustained period of four (4) hours."

19. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (2) (b) (ii) (iii) & (iv))

19.1. **Commission's Proposal**

19.1.1. The Commission had proposed the following in Regulation 24 (2) (b) (ii) (iii) & (iv) of the Draft Regulations

"ii) Ramp-up from fifty (50) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute and sustained operation at MCR for one (1) hour.

(iii) Demonstrate overload capability with valve wide open as per the CEA Technical Standards for Construction and sustained operation at that level for at least five (5) minutes.

(iv)Ramp-down from MCR to fifty (50) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute."

19.2. **Comments have been received from SRPC, Sembcorp, APP, Adani Power, NTPC.**

19.2.1. **SRPC** has suggested modifying clauses as provisions of CEA (Flexible operation of thermal power plants) Regulations.

19.2.2. **Sembcorp** suggested that the plants being operated by Sembcorp, 0.7% ramp rates are sustainable for wide range of 50% to 100% load variation. 1% can be achieved only for short ranges of 20%. Other thermal power plants may also not be able to operate at the ramp rates of up to 1% as proposed in the Draft Regulations.

19.2.3. **APP and Adani Power** have suggested the following,

1. *Ramp up must be tested from 55% and not from 50% of MCR.*
2. *Ramp up may be demonstrated for a particular small range only, and not from 55% to 100% MCR.*
3. *This ramp up capability test should not be part of COD and the same can be demonstrated separately. Depending on the unit condition (equipment /coal quality), ramp rate should be allowed to be declared by the generator.*

19.2.4. **NTPC** has suggested that the units have different coal mills, and varying the mill loading can only achieve a certain load range. Cutting in or out of milling systems needs to be considered as a part of ramp up or ramp down, and a 1% ramp rate test with two stabilization periods of 30 minutes each is required from 55% to 100% of MCR and vice versa.

19.3. **Analysis and Decision**

19.3.1. With respect to the suggestion of SRPC, it is clarified that ramp up tests as provided in Grid Code shall be furnished by the Generating Unit. The Generating station has to comply with technical requirement as stipulated in the CEA Technical Standards.

19.3.2. The suggestions of APP and Adani Power to consider ramping up from 55% in place of 50% have been accepted. Further, the tests have been provided for in the Grid Code on the basis of requirements stipulated under the CEA Technical

Standards for Construction and accordingly have been retained.

19.3.3. Accepting the suggestions of NTPC, the ramp rate in the generating station can be considered in two steps.

19.3.4. With respect to the suggestion of Sembcorp, it is noted that the CEA Technical Standards for Construction require ramp rate of 3% whereas the tests are provided in Grid Code for ramp rate of at least 1%. This cannot be reduced further as suggested by Sembcorp.

19.3.5. The suggestions of APP that ramp up capability test should not be part of COD is not accepted since the rationale for the introduction of tests prior to COD in Grid Code was provided in the Explanatory memorandum as follows:

"(b) Under the 2010 Grid Code, the entities such as generating stations and transmission licensee are required to furnish a certificate certifying that they comply with the applicable CEA Standards. However, with increasing size and complexities of power sector including integration with renewable sources and storage systems, the estimates of system as per simulation studies need to be as close to their real time response as possible. Hence, it has been proposed to take test reports of a few basic identified tests and specified documents to facilitate system studies by the system operator."

19.3.6. The regulation has been modified as follows, considering the suggestions of the stakeholders,

"(ii) Ramp-up from fifty-five (55) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute, in one step or two steps (with stabilization period of 30 minutes between two steps), and sustained operation at MCR for one (1) hour.
(iii) Demonstrate overload capability with the valve wide open as per the CEA Technical Standards for Construction and sustained operation at that level for at least five (5) minutes.
(iv) Ramp-down from MCR to fifty five (55) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute, in one or two steps (with stabilization period of 30 minutes between two steps)."

20. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (2) (b) (v)

20.1. **Commission's Proposal**

20.1.1. The Commission had proposed the following in Regulation 24 (2) (b) (v) of the Draft Regulations,

"(v) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 60%, 75% and 100% load."

20.2. **Comments have been received from SRPC and APP**

20.2.1. **SRPC** has suggested conducting the tests at a minimum turn down level also.

20.2.2. **APP** suggested that Primary frequency response depends on OEM logic configuration, and testing may be difficult if such testing provisions are not provided by OEM. This should not be part of COD, and the same can be demonstrated separately.

20.3. **Analysis and Decision**

20.3.1. With respect to the suggestion of APP, the Commission clarifies that Primary response is an essential requirement for grid stability. Testing is necessary to ensure the implementation of Primary response.

20.3.2. Considering the suggestion of SRPC test has been added at 55% loading also. The regulation has been modified as follows.

"(v) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 55%, 60%, 75% and 100% load."

21. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (2) (b) (vi)

21.1. **Commission's Proposal**

21.1.1. The Commission had proposed the following in Regulation 24 (2) (b) (vi) of the Draft Regulations:

"(vi)Reactive power capability as per the generator capability curve as provided by OEM considering over-excitation and under-excitation limiter settings."

21.2. **Comments have been received from NTPC.**

21.2.1. **NTPC** has commented that OEM documents showing the generator's reactive power capability curve must be submitted, and its demonstration is subject to the prevailing grid interconnection point voltage and technical limitations such as GT impedance and AVR limiters.

21.3. **Analysis and Decision**

21.3.1. Considering suggestions of NTPC, the regulation has been modified as follows,

"(vi) Reactive power capability as per the generator capability curve as provided by OEM considering over-excitation and under-excitation limiter settings <u>and prevailing grid condition."</u>

22. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (3))

22.1. **Commission's Proposal**

22.1.1. The Commission had proposed the following in Regulation 24 (3) of the Draft Regulations:

"(3) Documents and Tests Required for Hydro Generating Stations:

(a) The generating company shall submit OEM documents for turbine characteristics curve indicating the operating zone(s) and forbidden zone(s). In order to demonstrate operating flexibility of the generating unit, it shall be operated below and above the forbidden zone(s).

(b) The following tests shall be performed considering the water availability and head:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability.

(iv) Operation in synchronous condenser mode wherever designed."

22.2. **Comments have been received from KSEBL, NHPC, HPSLDC and SRPC.**

22.2.1. **KSEBL** suggested that PSS (Power System Stabiliser) tuning also be included for hydro stations with a capacity greater than 50 MW. A Protection testing report is also to be included.

22.2.2. **NHPC** requested that the generating station shall perform black start capability test whenever the conditions are simulated by RLDC and black start capability test should not be a mandatory condition for declaration of commercial operation date.

22.2.3. **HPSLDC** suggested that the regulation should be made mandatory for upcoming generators after the notification of the IEGC, 2022.

22.2.4. **SRPC** suggested adding to the clause, new tests, such as a sustained operation for at least 1 hour at minimum unit loading and Ramping capability as specified by OEM.

22.3. **Analysis and Decision**

22.3.1. With regard to suggestions of KSEBL to include PSS tuning and protection testing and SRPC to add additional tests, it is clarified that a generating unit is required to carry out all tests and mandates as per the CEA Construction Standards. However, for the purpose of the Grid Code, test reports for a few identified tests are specifically required to be submitted along with a Certificate from CMD/CEO/MD that the generating unit has complied with all CEA standards. Further, PSS should be done on a mandatory basis as per clause 29 (6) of these regulations.

22.3.2. Black start capability is a basic requirement for a hydro generating station and should be tested prior to the declaration of COD. However, checking of black start capability requires coordination with RLDC, and RLDC shall check the feasibility of conducting such a test and, accordingly, 'wherever feasible' has been inserted.

22.3.3. With regard to suggestions of HPSLDC, it is clarified that the Regulations are effective from 1.10.2023 and are applicable for all generating units declaring COD post 1.10.2023.

22.3.4. The regulation has been modified as follows,

"(4) Documents and Tests Required for Hydro Generating Stations including Pumped Storage Hydro Generating Station:

(a) The generating company shall submit OEM documents for the turbine characteristics curve indicating the operating zone(s) and forbidden zone(s). In order to demonstrate the operating flexibility of the generating unit, it shall be operated below and above the forbidden zone(s).

(b) The following tests shall be performed considering the water availability and head:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability<u>, wherever feasible</u>.

(iv) Operation in synchronous condenser mode wherever designed."

23. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (4))

23.1. **Commission's Proposal**

23.1.1. The Commission had proposed the following in Regulation 24 (4) of the Draft Regulations:

"(4) Documents and Test Required for Gas Turbine based Generating Stations:

(a) The generating company shall submit OEM documents for (i) starting time of unit in cold, warm and hot conditions (ii) design ramp rate.

(b) The following tests shall be performed:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability up to 100 MW capacity wherever designed.

(iv) Operation in synchronous condenser mode wherever designed."

23.2. **Comments have been received from Wartsila and POSOCO.**

23.2.1. **Wartsila** suggested that an Internal Combustion Engine (ICE) driven Generator Technology based generating station shall be included.

23.2.2. **POSOCO** has commented that the CEA Technical Standards for Connectivity (2013) specify that Hydro generating units with a rated capacity of 50 MW and above shall be capable of operation in synchronous condenser mode. POSOCO has suggested including "as per CEA Connectivity Standards" in the clause.

23.3. **Analysis and Decision**

23.3.1. The suggestion of Wartsila to add ICE based generators has not been accepted by the Commission, as there is no ICE based generator available under RLDC jurisdiction and the Commission will consider the suggestion as and when the situation arises.

23.3.2. We observe that the synchronous condenser mode, wherever designed, should be tested.

23.3.3. The draft regulation has been modified to include, Black start capability up to 100 MW capacity <u>wherever feasible,</u> as 24 (5) in the 2023 Grid Code Regulations as follows:

"(5) Documents and Test Required for Gas Turbine based Generating Stations:

(a) The generating company shall submit OEM documents for (i) starting time of the unit in cold, warm and conditions (ii) design ramp rate.

(b) The following tests shall be performed:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability up to 100 MW capacity, <u>wherever feasible</u>.

(iv) Operation in synchronous condenser mode wherever designed."

24. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (5) (a))

24.1. **Commission's Proposal**

24.1.1. The Commission had proposed the following in Regulation 24 (5) (a) of the Draft

Regulations:

"(5) Documents and Tests Required for the Generating Stations based on wind and solar resources:

(a) The generating company shall submit certificate confirming compliance to CEA Technical Standards for Connectivity."

24.2. **Comment has been received from POSOCO.**

24.2.1. POSOCO suggested that the generating company shall submit a certificate issued by an Accredited Certification Agency confirming compliance with the CEA Technical Standards for Connectivity.

24.3. **Analysis and Decision**

24.3.1. As per Regulation 26 (4) (a) Grid Code Regulations, 2023, the certificates submitted by the generating company shall have the signature of the authorised signatory not below the rank of CMD or CEO or MD. The suggestions of POSOCO to submit additional certificates by an Accredited Certification Agency is not accepted as of now since the agency which shall be the accreditation agency, which all certification agencies can certify the documents and tests, and the process to be followed by such agencies is yet to be established.

24.3.2. The draft regulation has been modified as follows,

"(6) Documents and Tests Required for the Generating Stations based on wind and solar resources:

(a) The generating company shall submit a certificate confirming compliance with CEA Technical Standards for Connectivity in accordance with sub-clause (a) of clause (4) of Regulation 26 of these regulations."

25. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (5) (b)

25.1. **Commission's Proposal**

25.1.1. The Commission had proposed the following in Regulation 24 (5) (b) of the Draft Regulations:

"(b) The following tests shall be performed:

(i) Frequency response of machines as per the CEA Technical Standards for Connectivity.

(ii) Reactive power capability as per OEM rating at the available irradiance or the wind energy, as the case may be.

(iii) Grid-forming capability, wherever provided, in inverter based units that may be used as black start resource"

25.2. **Comments have been received from SRPC, Adani Power, APP, AGEL, Tata Power, IWPA, Sembcorp and POSOCO.**

25.2.1. **SRPC** suggested that various modes like pf, voltage, fixed VAR etc., as well as night mode reactive power capability should also be tested.

25.2.2. **POSOCO** suggested including tests like Power Quality Assessment as per the CEA Technical Standards for Connectivity and Dynamic Reactive Power Support.

25.2.3. **Adani Power, APP and AGEL** suggested considering the test reports on a simulation basis or OEM certificates for commissioning. Actual test at plant level may be conducted in due course as feasible and availability of testing equipment at site.

25.2.4. **Tata Power** sought clarification whether the provisions are applicable only on the new RE projects (post the notification of these regulations) or to all the RE projects including existing ones.

25.2.5. **IWPA** has commented that it is not possible for wind and solar generators to conform to the frequency response requirement as the generation solely depends on the availability of the wind speed/Solar insolation. So, IWPA has requested that wind and solar generators be exempted from this requirement.

IWPA also commented that all wind energy generators are not equipped to provide reactive power support. It is possible only in gearless and DFIG WEGs. So IWPA has requested that this clause be exempted in case of the WEGs that are not equipped to provide Reactive power.

25.2.6. **Sembcorp** has commented that the grid forming capability is a recent technology and hence, prospective effect for projects based on the criterion specified separately by CEA as this field is still evolving.

25.3. **Analysis and Decision**

25.3.1. With regard to suggestions of SRPC and POSOCO to add additional tests, the Commission is of the opinion that the regulation encompasses the essential test requirements. In addition, for other compliance matters, a certificate signed by the authorized signatory of the generating company is required to be submitted.

25.3.2. With respect to the suggestion of Tata Power, the Commission clarifies that these regulations will apply to plants that achieve COD after the effective date of these regulations.

25.3.3. Considering the suggestions from Adani Power, APP, AGEL, and IWPA, the Commission has inserted a provision for offline simulation studies for specified tests in case testing is not feasible before COD with the condition that tests be performed within one year of COD.

25.3.4. With respect to the suggestion of Sembcorp, Commission clarifies that the regulation regarding grid forming capability has been omitted due to its status as an evolving technology. The same may be considered in the regulations when the need arises.

25.3.5. The draft regulation has been modified as 24 (6) (c) in the 2023 Grid Code Regulations as follows,

"(c) The following tests shall be performed at the point of interconnection:

(i) Frequency response of machines as per the CEA Technical Standards for Connectivity.

(ii) Reactive power capability as per OEM rating at the available irradiance or the wind energy, as the case may be.

Provided that the generating company may submit offline simulation studies for the specified tests, in case testing is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD."

26. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (6))

26.1. Commission's Proposal

26.1.1. The Commission had proposed the following in Regulation 24 (6) of the Draft Regulations:

"(6) Documents and Tests Required for Energy Storage Systems:

(a) The ESS shall submit certificate confirming compliance to the CEA Technical Standards for Connectivity.

(b) The following tests shall be performed:

(i) Power output capability in MW and energy output capacity in MWh."

26.2. Comments have been received from SRPC, POSOCO, and SECI.

26.2.1. **SRPC** suggested that the Charging capability of BESS also needs to be added in the tests in b(i) clause. **SRPC** and **SECI** suggested adding a new test for Grid-forming capability.

26.2.2. **POSOCO** suggested including tests like Power Quality Assessment as per the CEA Technical Standards for Connectivity and Dynamic Reactive Power Support.

26.3. Analysis and Decision

26.3.1. The Commission is of the opinion that the regulation already encompasses the essential test requirements. In addition, for other compliance matters, a certificate signed by the authorized signatory of the generating company is required to be submitted. Further, as ESS is an evolving technology, additional tests may be added as the need arises.

26.3.2. The regulation has been modified as follows,

"(7) Documents and Tests Required for Energy Storage Systems:

(a) The ESS shall submit a certificate confirming compliance with the CEA Technical Standards for Connectivity in accordance with sub-clause (a) of clause (4) of Regulation 26 of these regulations.

(b) The following tests shall be performed at the point of interconnection:

(i) Power output capability in MW and energy output capacity in MWh.

(ii) Frequency response of ESS.

(iii) Ramping capability as per design."

27. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (7))

27.1. Commission's Proposal

27.1.1. The Commission had proposed the following in Regulation 24 (7) of the Draft Regulations:

"(7) Documents and Tests Required for HVDC Transmission System

(a) The transmission licensee shall submit technical details including operating guidelines such as filter bank requirements at various operating loads and monopolar/ or bipolar configuration, reactive power controller, power demand overrides, run-back features, frequency controller, reduced voltage mode of operation and power oscillation damping.

(b) The following tests shall be performed:

(i) Minimum load operation.
(ii) Ramp rate.
(iii) Overload capability.
(iv) Black start capability in case of Voltage source convertor (VSC) HVDC."

27.2. **Comments have been received from Siemens Limited, Power Grid and POSOCO.**

27.2.1. **Siemens Limited** suggested adding a DC Line Fault Clearing and Recovery Sequence test, in cases where DC transmission medium involves overhead line.

27.2.2. **Power Grid** suggested that the black start capability test should be done within the rated capability of the HVDC system.

27.2.3. **POSOCO** suggested that the transmission licensee should also submit the technical details, circuit design parameters, and protection philosophy document. Further, POSOCO has also sought additional reports like, Power Oscillation Damping (POD), Sub synchronous Torsional Interaction (SSTI), Frequency Controller, Multi-infeed interaction Study Report and Dynamic Performance Study. POSOCO also requested the Commission to include tests for POD performance, Dynamic performance test and Dynamic Reactive Power Support (in case of VSC based HVDC).

27.3. **Analysis and Decision**

27.3.1. With respect to the suggestion of Power Grid, the Commission clarifies that the tests will be performed as per testing standards in coordination with RLDC and black start capability shall be tested prior to COD, wherever feasible.

27.3.2. All the requested additional reports/tests by POSOCO and Siemens have not been incorporated into the regulations. The Commission is of the opinion that the regulation already encompasses the essential test requirements. In addition, for other compliance matters, a certificate signed by the authorized signatory of the generating company must be submitted. If there is a need for case specific reports/tests, these additional requirements may be sought by RLDC from the entity. The additional tests for dynamic reactive power support and details of circuit design parameters, have been provided for in the regulations.

27.3.3. The draft regulation has been modified as 24 (8) in the 2023 Grid Code Regulations as follows,

"(8) Documents and Tests Required for HVDC Transmission System:
(a) The transmission licensee shall submit technical details including operating guidelines such as filter bank requirements at various operating loads and monopolar/ or bipolar configuration, reactive power controller, run-back features, frequency controller, reduced voltage mode of operation, circuit design parameters and power oscillation damping, as applicable.
(b) The following tests shall be performed:
(i) Minimum load operation.
(ii) Ramp rate.
(iii) Overload capability, subject to grid condition.
(iv) Black start capability in the case of Voltage source convertor (VSC) HVDC wherever feasible.
(v) Dynamic Reactive Power Support (in the case of VSC based HVDC)"

28. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION (Regulation 24 (8))

28.1. Commission's Proposal

28.1.1. The Commission had proposed the following in Regulation 24 (8) of the Draft Regulations:

"(8) Documents and Tests Required for SVC/STATCOM

(a) The transmission licensee shall submit technical particulars including operating guidelines such as number of blocks and rating of each block, single line diagram, V/I characteristics, rating of coupling transformer, MSR/MSC design parameters, different operating modes, IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not then reasons for same) and the results of Offline simulation-based study to validate the performance of POD.

(b) The following tests shall be performed to validate full reactive power capability of SVC and STATCOM in both the directions i.e. absorption as well as injection mode:

(i) POD performance test.

(ii) dynamic performance testing."

28.2. Comments have been received from Power Grid

28.2.1. **Power Grid** has requested the Commission to check whether the technical particulars Number of blocks and rating of each block, MSR and MSC design parameters need to be submitted.

28.3. Analysis and Decision

28.3.1. The suggestions of Power Grid have been accepted and "*number of blocks and rating of each block"* have been deleted. A clause for offline simulation studies in case conduct of tests is not feasible before COD has also been inserted.

28.3.2. The regulation has been modified as follows,

"(8) Documents and Tests Required for SVC or STATCOM

(a) The transmission licensee shall submit technical particulars including a single line diagram, V/I characteristics, the rating of coupling transformer, the rating of each VSC, MSR and MSC branch, different operating modes, the IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not, then reasons for the same) and the results of an Offline simulation-based study to validate the performance of POD.

(b) The following tests shall be performed to validate the full reactive power capability of SVC and STATCOM in both directions i.e. absorption as well as injection mode:

(i) POD performance test.

(ii) dynamic performance testing:

Provided that the transmission licensee may submit offline simulation studies for the specified tests, in case the conduct of tests is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD."

29. CERTIFICATE OF SUCCESSFUL TRIAL RUN (Regulation 25 (1))

29.1. Commission's Proposal

29.1.1. The Commission had proposed the following in Regulation 25 (1) of the Draft

Regulations:

“(1) In case any objection is raised by a beneficiary in writing to the concerned RLDC with copy to all concerned regarding the trial run within two (2) days of completion of such trial run, the concerned RLDC shall, within five (5) days of receipt of such objection, in coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or there is a need for repeat trial run.”

29.2. **Comments have been received from MP Power Management Company, NHPC and POSOCO.**

29.2.1. **MP Power Management Company** suggested increasing the beneficiary time to raise objections from 2 days to 7 days.

29.2.2. **NHPC** suggested reducing the RLDC time period from 5 days to 3 days.

29.2.3. **POSOCO** commented on increasing the time period for the issuance of a certificate by RLDC after a successful trial run from 3 days to 7 days.

29.3. **Analysis and Decision**

29.3.1. The request for an extension of the current timeline has been rejected since a generating station would like to declare COD soon on completion of the trial run, and the provision as proposed in the Draft Regulations has been retained.

30. CERTIFICATE OF SUCCESSFUL TRIAL RUN (Regulation 25 (2))

30.1. **Commission’s Proposal**

30.1.1. The Commission had proposed the following in Regulation 25 (2) of the Draft Regulations,

“(2) After completion of successful trial run and receipt of documents and test reports as per Regulation 24 of these regulations, the concerned RLDC shall issue a certificate to that effect to the concerned generating station, ESS or transmission licensee, as the case may be, with a copy to their respective beneficiary(ies).”

30.2. **Comments have been received from SRPC, POSOCO, NTPC, HPSLDC and Sembcorp.**

30.2.1. **SRPC** suggested adding “and respective RPC” at the end of the clause.

30.2.2. **POSOCO** commented that the timeline of 3 days shall be mentioned for issuance of the certificate by RLDC after a successful trial run.

30.2.3. **NTPC, HPSLDC** commented that specific time limit should be provided for RLDC to declare whether the trial run was successful or there is a need for repeat trial run. (In the Existing IEGC 2010 – The Time period is 7 days) and for the RE station the same shall be communicated within 3 days.

30.2.4. **Sembcorp** suggested deleting this clause because beneficiaries have no role in raising objections to trial runs supervised by RLDC, and some plants on a merchant basis may not have beneficiaries, making the proposed clause irrelevant. If beneficiaries raise objections, it could question the legitimacy of RLDC as a statutory authority.

30.3. **Analysis and Decision**

30.3.1. The suggestion of SRPC has been accepted by the Commission and accordingly copy of the certificate shall also be furnished to RPC.

30.3.2. Considering suggestions of POSOCO and NTPC, a timeline of '3' days has been inserted.

30.3.3. The Commission clarifies that in cases where power is tied up through a PPA, beneficiaries may raise an objection. However, in the case of Merchant power, where there are no identified beneficiaries, no objection can be raised by the beneficiaries.

30.3.4. Regulation 25 (2) has been modified as follows,

"(2) After completion of a successful trial run and receipt of documents and test reports as per Regulation 24 of these regulations, the concerned RLDC shall issue a certificate to that effect to the concerned generating station, ESS or transmission licensee, as the case may be, with a copy to their respective beneficiary(ies) <u>and the respective RPC, within three days</u>."

31. DECLARATION BY GENERATING COMPANY AND TRANSMISSION LICENSEE (Regulation 26 (1)(a))

31.1. **Commission's Proposal**

31.1.1. The Commission had proposed the following in Regulation 26 (1) (a) of the Draft Regulations:

"(1) Thermal Generating Station

(a) The generating company shall certify that:

(i) The generating station or unit thereof meets the relevant requirements and provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations, as applicable."

31.2. **Comments have been received from SRPC.**

31.2.1. SRPC suggested adding the regulation "CEA (Flexible operation of thermal power plants) Regulations" also in the clause.

31.3. **Analysis and Decision**

31.3.1. Considering the suggestion of SRPC, the regulation has been modified as follows,

"(1) Thermal Generating Station

(a) The generating company shall certify that:

(i) The generating station or unit thereof meets the relevant requirements and provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations,2010, <u>CEA (Flexible operation of thermal power plants) Regulations,2023 and these regulations, as</u> applicable."

32. DECLARATION BY GENERATING COMPANY AND TRANSMISSION LICENSEE (Regulation 26 (1)(b), 26 (3)(a) and 26 (4) (a))

32.1. **Commission's Proposal**

32.1.1. The Commission had proposed the following in Regulation 26 (1) (b), 26 (3)(a) and 26 (4) (a) of the Draft Regulations:

"(1) Thermal Generating Station

(b) The certificates as required under clause (a) of this Regulation shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the generating company and shall be submitted to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD.

(3) Transmission system

(a) The transmission licensee shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD of the company to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations and are capable of operation to their full capacity.

(4) Wind, Solar, Storage, and Hybrid Generating Station

(a) The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations."

32.2. **Comments have been received from Tata Power, Statkraft, Power Grid, IWPA, Adani Power, APP, NTPC, Sterlite, BALCO, AGEL, MP Power Management Company and POSOCO.**

32.2.1. **TATA Power** suggested that in the case of RE projects of small scale and size, these are typically headed by Engineers/mid management. Hence, such a specific requirement of authorized signatory not below the rank of CMD or CEO or MD, may be deleted.

32.2.2. **Statkraft and Power Grid** suggested adding Company Secretary or person Authorized by the Board of Directors as the authorised signatory.

32.2.3. **IWPA** suggested replacing "signed by an authorised person" with "any officer authorized by the Board of the Company" in the clause, in order to facilitate the Generators to sign by an authorised person.

32.2.4. **Adani Power, APP, NTPC, Sterlite, BALCO, AGEL** suggested that the requirement of declaration to be signed by an authorized signatory not below the rank of CMD or CEO or MD be replaced with authorized signatory/ Head of Project/ Director of the Company.

32.2.5. **MP Power Management Company** suggested retaining the existing IEGC, 2010 clause that the Generating Company shall submit approval of the Board of Directors for the certificates as required under clause (iii) within a period of 3 months of COD. Further, approval from the Board of Directors plays an important role in the approval of capex cost & also at the time of prudence check.

32.2.6. **POSOCO** suggested adding "NLDC/RLDC First time energisation procedure" after CEA Technical Standards for Communication in the clause.

32.3. **Analysis and Decision**

32.3.1. The Commission believes that all the requirements under CEA Standards are not being asked to be submitted as part of declaration of COD by the entities. Hence the Certificate of compliance with CEA Standards needs to be signed by the CMD/CEO/ Managing Director (MD) of the company considering the sensitive importance of these documents and the same is not to be delegated.

32.3.2. The requirement of approval from the Board of Directors is not accepted.

32.3.3. The compliance with the first time energization procedure is a part of these regulations and need not be added specifically in the Certificate.

32.3.4. Regulation 26 (3) (a) has been modified (underlined) as follows.

"(3) Transmission system

(a) The transmission licensee shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD of the company to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, <u>Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations,2010</u> and these regulations and are capable of operation to their full capacity."

"(4) Wind, Solar, Storage, and Hybrid Generating Station

(a) The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, <u>Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations,2010</u> and these regulations."

33. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1))

33.1. **Commission's Proposal**

33.1.1. The Commission had proposed the following in Regulation 27 (1) of the Draft Regulations:

"(1) A generating station or unit thereof or a transmission system or an element thereof or ESS may declare commercial operation as follows and inform CEA, the concerned RLDC, the concerned RPC and its beneficiaries:"

33.2. **Comments have been received from WRPC.**

33.2.1. WRPC suggested that a one-time revision of the COD should be made by RPCs in consultation with beneficiaries of the station if outages are availed by the entity within a period of 3-months or any reasonable time of the commissioning (for the purpose of regular maintenance/carry out leftover work during commissioning) and the revised COD date will be considered as the date of taking the element back in service after such outage.

33.3. **Analysis and Decision**

33.3.1. The suggestion made by WRPC has not been accepted because the declaration of COD will only be made after all the necessary work has been completed and a proper trial has been conducted. Hence, the provision as proposed in the Draft Regulations has been retained.

34. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(a)(i))

34.1. **Commission's Proposal**

34.1.1. The Commission had proposed the following in Regulation 27(1) (a)(i) of the Draft Regulations:

"(a) Thermal Generating Station or a unit thereof

(i) The commercial operation date in case of a unit of the thermal generation station shall be the date declared by the generating company after successful trial run at MCR or de-rated capacity as per Regulation 22 (1)(b), as the case may be, and submission of declaration as per Regulation 26(1) of these regulations."

34.2. **Comments has been received from MP Power Management Company.**

34.2.1. **MP Power Management Company** suggested that COD is a critical parameter, for maintaining clarity in this matter, it is pertinent to adopt the definition as per the existing IEGC that should necessarily have the provision of "getting clearance from the respective RLDC or SLDC" for all, i.e., Thermal, Hydro, Renewable Generator and Transmission elements.

34.3. **Analysis and Decision**

34.3.1. The suggestion of MP Power Management Company has already been taken care of, as the successful trial run certificate is provided by RLDC.

34.3.2. The provision as proposed in the Draft Regulations has been retained.

35. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(a)(ii))

35.1. **Commission's Proposal**

35.1.1. The Commission had proposed the following in Regulation 27(1) (a)(ii) of the Draft Regulations:

"(a) Thermal Generating Station or a unit thereof

(ii) In case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station."

35.2. **Comments from NTPC.**

35.2.1. NTPC suggested that in the case of RE generating stations, a suitable provision for declaration of COD of remaining part capacity beyond 50 MW is required.

35.3. **Analysis and Decision**

35.3.1. The Commission has already considered NTPC's suggestion. It has been provided that a minimum trial run of 50 MW will be conducted. If the plant's capacity exceeds 50 MW, the trial run will be conducted in batches of no less than 5 MW.

35.3.2. The provision as proposed in the Draft Regulations has been retained.

36. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(c)(i))

36.1. **Commission's Proposal**

36.1.1. The Commission had proposed the following in Regulation 27(1) (c)(i) of the Draft Regulations:

"(c)Transmission System

(i) The commercial operation date in case of an Inter-State Transmission System or an element thereof shall be the date declared by the transmission licensee on which the Transmission System or an element thereof is in regular service at 0000 hours after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end as per Regulation 23 and submission of declaration as per Regulation 26(3) of these regulations.

…

Provided also that in case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee may declare deemed COD of the ISTS in accordance with the provisions of the Transmission Service Agreement after obtaining a certificate from the CTU to the effect that the transmission system is complete as per the specifications of the bidding guidelines and applicable CEA Standards."

36.2. **Comments have been received from CTU, POSOCO, SLDC Odisha, Adani Power and Power Grid.**

36.2.1. **CTU** has commented that CEA issues a certificate to the transmission licensee itself for fulfilment of applicable CEA standards as per existing practices and has suggested to include a certificate from CEA to the effect that the transmission system is complete as per the applicable CEA Standards.

36.2.2. **POSOCO** commented that as per existing practice, RLDC used to issue a No Load charging certificate.

36.2.3. **SLDC Odisha** requested clarity on the date from which the tariff shall be calculated in case of DOCO of the idle charged Transmission element.

36.2.4. **Adani Power** submitted that the Transmission licensees take the approval of CEA by way of inspection of Electrical installations of transmission system developed by the Licensees. CEA also gives approval for the energization of Electrical installations as per the CEA (Measures relating to Safety and Electrical Supply) regulation, 2010. Therefore, the purpose of also having the approval of CTU for the same is not clear, and moreover, there will be duplication of work as both CTU and CEA will certify the CoD of the project.

36.2.5. **Power Grid** suggested that in the third proviso of Regulation, RLDCs instead of RPCs may be given the responsibility of such certification. After SCOD, its COD may be allowed irrespective of commissioning of generating station or complete ATS. Considering this the first proviso of Regulation 27.1.c.i. may be restricted to COD before SCOD only.

36.3. **Analysis and Decision**

36.3.1. With regard to suggestions of CTU and Adani Power to relook into certification by CTU, it is clarified that in case of declaration of COD of such an element which is not carrying power, there is a requirement for double check that the element is otherwise complete as per the scope of works to ensure that only completed element has been granted COD since commercial liabilities start on COD. An element that carries power is automatically checked by way of carrying power. Accordingly, the certification by CTU has been retained.

36.3.2. The suggestion of POSOCO has been accepted by the Commission

36.3.3. In respect to the suggestion of SLDC Odisha, the Commission provides clarification that the tariff shall start from the COD in terms of provisions of the Sharing Regulations.

36.3.4. Commission clarifies that Regulation 2 (g) of the Sharing Regulations defines COD of the Associated Transmission System as COD of the last transmission element of the Associated Transmission System. Accordingly, the first proviso has been proposed wherein the COD of any transmission element that is a part of the Associated Transmission System (ATS) shall be declared only after a successful trial run of the last element of the said ATS. Such conditions cannot be relaxed since commercial liability starts soon after COD and before completion of all elements of ATS, COD cannot be declared for individual elements unless approved by RPC.

36.3.5. Regulation 27 (1) (c) (i) of the 2023 Grid Code Regulations have been modified as follows:

"(c) Transmission System

(i) The commercial operation date in the case of an Inter-State Transmission System or an element thereof shall be the date declared by the transmission licensee on which the Transmission System o r an element thereof is in regular service at 0000 hours after successful trial operation for transmitting electricity and communication signals from the sending end to the receiving end as per Regulation 23 and submission of a declaration as per clause (3) of Regulation 26 of these regulations.

…

Provided also that in the case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee may declare deemed COD of the ISTS in accordance with the provisions of the Transmission Service Agreement after obtaining <u>(a)a certificate from the CTU to the effect that the transmission system is complete as per the specifications of the bidding guidelines and applicable CEA Standards and (b) no load charging certificate from the respective RLDC, where no load charging is possible</u>."

37. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(c)(ii))

37.1. **Commission's Proposal**

37.1.1. The Commission had proposed the following in Regulation 27(1)(c)(ii) of the Draft Regulations"

"(ii) The COD of a transmission element of the transmission system under Tariff Based Competitive Bidding shall be declared only after declaration of COD of all the pre-required transmission elements as per the Transmission Services Agreement:

Provided that in case any transmission element is required in the interest of the power system as certified by concerned RPC(s), the COD of the said transmission element may be declared prior to the declaration of COD of its pre-required transmission elements."

37.2. **Comments have been received from MSEDCL, and Power Grid.**

37.2.1. **MSEDCL** has commented that the entity (generating station or transmission company) responsible for the delay in commissioning of the upstream and downstream network or generating station shall be responsible for bearing the charges of the commissioned transmission element.

37.2.2. **Power Grid** has suggested that for conditions specified in the first proviso of Regulation 27(1) (c) (ii), RLDCs instead of RPCs may be given the responsibility to such certification. Further, CEA can also be considered for the role if required.

Power Grid has commented that if RPCs are to certify that the COD of an element is required in the interest of the grid, then depending upon the periodicity of RPC meetings, it may result in a delay in the declaration of COD. Further, as practise, it may happen that RPC may send such proposals to its various technical sub committees which can further delay the declaration of COD.

37.3. **Analysis and Decision**

37.3.1. In respect to the suggestion of MSEDCL, the Commission clarifies that the responsibility to bear charges due to delay is already covered in the Sharing Regulations.

37.3.2. In respect to the suggestion of Power Grid, the Commission clarifies that transmission licensee should approach the RPC with adequate notice, so that COD is not delayed. Further it is clarified that since transmission licensee seeks to delink elements from pre-required elements and involves commercial liabilities, it should be discussed at RPC level which involves RLDC as well as the beneficiaries.

37.3.3. The provision as proposed in the Draft Regulations has been retained.

38. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(d))

38.1. **Commission's Proposal**

38.1.1. The Commission had proposed the following in Regulation 27(1) (d) of the Draft Regulations:

"(d) Communication System

Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of *which a communication system or element thereof shall be put into service after completion of site acceptance test including transfer of voice and data to the respective control centres as certified by the respective Regional Load Despatch Centre."*

38.2. **Comment has been received from WRPC.**

38.2.1. **WRPC** has suggested that the elements of communication system such as RTUs/transducers should be compliant with the accuracy class specified for such elements, and the measurements received through SCADA at SLDCs/RLDCs should be within the permissible limit of the accuracy class of such elements. The accuracy class shall be 0.5 or lower for these equipment's.

38.3. **Analysis and Decision**

38.3.1. The Commission clarifies that all the Communication system will be as per the CEA standards and therefore, it has not been included here.

38.3.2. The provision as proposed in the Draft Regulations has been retained.

39. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (1)(e)(i))

39.1. **Commission's Proposal**

39.1.1. The Commission had proposed the following in Regulation 27(1) (e) (i) of the Draft Regulations:

"(e) Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

(i)The commercial operation date in case of units of a renewable generating station aggregating to 50 MW and above shall mean the date declared by the generating station after undergoing successful trial run as per clause (3) of Regulation 22 of these regulations submission of declaration as per clause (4) of Regulation 26 of these regulations, and subject to fulfilment of other conditions, if any as per PPA."

39.2. **Comments have been received from NTPC, BALCO, Sterlite and SRPC.**

39.2.1. **NTPC** suggested that in case of RE generating stations a suitable provision for declaration of CoD of remaining part capacity beyond 50 MW is required.

39.2.2. **BALCO and Sterlite** have requested to allow the capacity of 25 MW to declare commissioning, as commissioning capacity aggregating to 50 MW leads to huge wastage. Achieving such size takes some time, during which the modules which are already placed in the field are ready for generating power.

39.2.3. **SRPC** suggested substituting the word "PPA" with "PPA/PSA" and also to substitute 50 MW with 5 MW in the clause.

39.3. **Analysis and Decision**

39.3.1. In respect to the suggestion of NTPC, the Commission clarifies that suitable provision has already been provided in Regulation 22 (3) (a) of the Grid Code Regulations, 2023.

39.3.2. The Commission clarifies that the minimum capacity required for the trial run should 50 MW or such other limit as per the minimum capacity for Connectivity to ISTS under the GNA Regulations.

39.3.3. The Commission also clarifies that for COD, the generating station must also fulfil the conditions as per the agreement signed by the generator i.e. PPA or PSA.

39.3.4. Regulation has been modified as follows:

"e) Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

(i) The commercial operation date in the case of units of a renewable generating station aggregating to 50 MW and above or such other limit as specified in clause (3) of Regulation 22 of these regulations, shall mean the date declared by the generating station after undergoing a successful trial run as per clause (3) of Regulation 22 of these regulations, submission of declaration as per clause (4) of Regulation 26 of these regulations, and subject to fulfilment of other conditions, if any, as per PPA."

40. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD) (Regulation 27 (2))

40.1. Commission's Proposal

40.1.1. The Commission had proposed the following in Regulation 27(2) of the Draft Regulations:

"(2) Scheduling of generating station or unit thereof shall start from 0000 hours of the Commercial Operation Date of the said generating station or unit thereof."

40.2. Comments have been received from SRPC and POSOCO.

40.2.1. **SRPC** suggested inserting the sentence "Intimation of Commercial Operation Date shall be at least 24 hrs before" at the end of the clause.

40.2.2. **POSOCO** suggested that the scheduling of the generating station shall start from D+3, where D is the day when COD is declared.

40.3. Analysis and Decision

40.3.1. Considering suggestions of POSOCO, the Regulation has been modified as follows:

"(2) Scheduling of the generating station or unit thereof shall start from 0000 hours of D+2 (where D is the Commercial Operation Date of the said generating station or unit thereof)."

40.3.2. The issue of declaration of COD was brought to the notice of the Commission by THDC, NHPC and Grid-India and has been addressed vide Order dated 30.09.2023 in Petition No. 14/SM/2023 quoted as follows:

"7. The above provisions in the Grid Code were incorporated after considering the comments of the POSOCO/Grid-India on the draft Grid code where it was suggested that considering the need for assessment of margins before scheduling and the timelines to be adhered to for unit commitment decisions, scheduling of inter-regional and international transactions, gate closure, and commencement of scheduling after declaration of COD by the Users should be from 0000 hrs of D+3, where D day is the date when COD is declared by the User.

8. We observe that the requirement of Grid India is about prior information before scheduling starts so that necessary steps may be taken by it to facilitate scheduling. Hence, we are of the considered view that 'D' referred to in Clause 2 of Regulation 27 of the Grid Code shall be construed as the date when a generating station intimates the commercial operation of the generating station or unit thereof, and the scheduling shall start from 0000 hours of D+2 day. For instance, if a generating station wishes to declare its commercial operation at 0000 hrs on 5.11.2023 it must intimate the date of commercial operation at the latest by 3.11.2023 and communicate to RLDC so that scheduling can start at 0000 hrs on 5.11.2023. In this case, 'D' is 3.11.2023, when the generating station issues the letter declaring its COD with effect from 5.11.2023 at 00 hrs.

CHAPTER 6 - OPERATING CODE

1. Operating Philosophy (Regulation 28 (1))

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation 28 (1) of the Draft Regulations:

"(1) All entities such as NLDC, RLDCs, SLDCs, CTU, STUs, RPCs, power exchanges, QCAs, SNAs, licensees, generating stations and other grid connected entities shall at all times function in coordination to ensure stability and resilience of the grid and achieve maximum economy and efficiency in operation of power system".

1.2. **Comments have been received from POSOCO**

1.2.1. **POSOCO** commented that 'integrity' and 'resilience' may be included as one of the objectives of the Operating code.

1.3. **Analysis and Decision**

1.3.1. The suggestions of POSOCO have been accepted. The Commission has noted the suggestions of the stakeholders

1.3.2. Regulation 28 (1) of the 2023 Grid Code Regulations has been modified as follows:

"28 (1) All entities, such as NLDC, RLDCs, SLDCs, CTU, STUs, RPCs, power exchanges, QCAs, SNAs, licensees, generating stations, and other grid connected entities shall at all times function in coordination to ensure integrity, stability and resilience of the grid and achieve economy and efficiency in the operation of power system."

2. Operating Philosophy (Regulation 28 (6))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation 28 (6) of the Draft Regulations:

"(6) NLDC, RLDCs and SLDCs shall have qualified operating personnel manning the control room round the clock."

2.2. **Comments have been received from SRPC and POSOCO**

2.2.1. **SRPC** and **POSOCO** suggested replacing the words "qualified operating personnel" with "certified operating personnel (including for communication/SCADA)".

2.3. **Analysis and Decision**

2.3.1. It is clarified that there is a mechanism for certification of system operators, however it is not mandated for SLDCs. Hence, 'qualified' would include certified as per the mechanism with RLDC/NLDC/SLDCs.

2.3.2. The provision as proposed in the Draft Regulations has been retained.

3. Operating Philosophy (Regulation 28 (7) and 28(8))

3.1. **Commission's Proposal**

3.1.1. The Commission had proposed the following in Regulation 28 (7) of the Draft Regulations:

"(7) Every generating station and transmission substation of 132 kV and above shall have a control room manned by qualified operating personnel round the clock. Alternatively, the same may be operated round the clock from a remotely located control room, subject to the condition that such remote operation does not result in delay in execution of any switching instructions and information flow:

Provided that a transmission licensee owning a transmission line but not owning the connected substation, shall have a round the clock coordination centre.

(8) SNA and QCA shall have round the clock coordination centres manned by qualified personnel for operational coordination with the concerned load despatch centres and generating stations."

3.2. **Comments have been received from KSEBL, PCKL, KPTCL, HPSLDC and POSOCO**

3.2.1. **KSEBL**, **PCKL,** and **KPTCL** suggested replacing the word 132 kV with 110 kV as they have stations at a voltage level of 110KV.

3.2.2. **HPSLDC** suggested that there should be a provision for the course of action in case of noncompliance

3.2.3. **POSOCO** suggested that the Energy Storage System (ESS), Bulk Consumer, Electrolyser Plant, and Lift Irrigation Pumping Station facilities should be mandated to maintain control and coordination rooms equipped with hotline communication facilities between SLDC/RLDC, along with voice communication and internet connectivity and shall be manned by qualified operating personnel round the clock. **POSOCO** suggested adding REGS and RHGS to clause (8).

3.3. **Analysis and Decision**

3.3.1. The suggestions of KSEB, PCKL, and KPTCL to include 110 kV have been accepted.

3.3.2. HPSLDC suggestion gets addressed under the Monitoring and Compliance code.

3.3.3. It is observed that REGS and RHGS are covered under Regulation 28(7) under the generating station.

3.3.4. Considering the suggestion made, Regulations 28 (7) and 28 (8) of the 2023 Grid Code Regulations have been modified as follows:

"28 (7) Every generating station, and transmission substation of 110 kV and above shall have a control room manned by qualified operating personnel round the clock. Alternatively, the same may be operated round the clock from a remotely located control room, subject to the condition that such remote operation does not result in a delay in the execution of any switching instructions and information flow:

Provided that a transmission licensee owning a transmission line but not owning the connected substation, shall have a coordination centre functioning round the clock, manned by qualified personnel for operational coordination with the concerned load despatch centres and equipped to carry out the operations as directed by concerned load despatch centres.

(8) SNA and QCA shall have coordination centres functioning round the clock, manned by qualified personnel for operational coordination with the concerned load despatch centres and generating stations. ESS and Bulk Consumers, which are regional entities

shall have coordination centres functioning round the clock and manned by qualified personnel for operational coordination with the concerned load despatch centres."

4. System Security (Regulation 29 (2) (a))

4.1. **Commission's Proposal**

4.1.1. The Commission had proposed the following in Regulation 29 (2) (a) of the Draft Regulations:

"(2) Isolation, Taking out of service and Switching off of an element of the grid:
(a) No element(s) of the grid shall be isolated from the grid, except (i) during emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be, where such isolation would prevent a total grid collapse or would enable early restoration of power supply; (ii) for safety of human life; (iii) when serious damage to a costly equipment is imminent and such isolation would prevent it; and (iv) when such isolation is specifically instructed by NLDC or RLDC or SLDC, as the case may be."

4.2. **Comments have been received from BYPL, GRIDCO and POSOCO**

4.2.1. **BYPL** requested more clarity on costly equipment.

4.2.2. **GRIDCO** requested also to include animal life at the end of sub-clause 29(2)(a)(ii).

4.2.3. **POSOCO** suggested adding one more additional sub-clause as below:

'(v) if any such isolation is made by any entity, such entity shall inform the concerned LDC within the next 10 minutes and submit a justification for the same on the next working day.'

4.3. **Analysis and Decision**

4.3.1. The word 'costly equipment' in the draft regulation has been replaced with 'critical equipment, in the final regulation to avoid ambiguity.

4.3.2. Animal life has not been inserted and the same may be considered by SLDC under the State Grid Code, as required.

4.3.3. Suggestions of POSOCO to insert a timeline to report isolation event by any entity to RLDC/SLDC has been accepted.

4.3.4. Regulation 29 (2) (a) of the 2023 Grid Code Regulations has been modified as follows:

"(2) Isolation, Taking out of service and Switching off an element of the grid:
(a) No element(s) of the grid shall be isolated from the grid, except (i) during an emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be, where such isolation would prevent a total grid collapse or would enable early restoration of power supply; (ii) for the safety of human life; (iii) when serious damage to a <u>critical</u> equipment is imminent and such isolation would prevent it; and (iv) when such isolation is specifically instructed by NLDC or RLDC or SLDC, as the case may be. A<u>ny such isolation shall be reported to the respective RLDC or SLDC within the next 15 minutes</u>."

5. System Security (Regulation 29 (2) (b))

5.1. **Commission's Proposal**

5.1.1. The Commission had proposed the following in Regulation 29 (2)(b) of the Draft Regulations:

“(b) Each RLDC, in consultation with CTU, the concerned users, SLDCs, STUs, shall prepare a list of important elements in the regional grid, including those in the State grids which are critical for regional grid operation and shall make available the said list to all concerned”.

5.2. **Comments have been received from WRPC**

5.2.1. **WRPC** has commented that RPCs are also required to be consulted since the list of all important elements is required for transmission element outage planning and suggested that RPCs shall also be included in the clause.

5.3. **Analysis and Decision**

5.3.1. The suggestion of WRPC has been accepted. CTU and STU are already included in the definition of ‘users’, and hence the specific reference to CTU and STU has been deleted.

5.3.2. Regulation 29 (2) (b) of the 2023 Grid Code Regulations has been modified as follows:

“(b) Each RLDC, in consultation with the concerned RPCs, users, SLDCs, shall prepare a list of important elements in the regional grid, including those in the State grids that are critical for regional grid operation and shall make the said list available to all concerned.”

6. System Security (Regulation 29 (2)(c))

6.1. **Commission’s Proposal**

6.1.1. The Commission had proposed the following in Regulation 29 (2)(c) of the Draft Regulations:

“(c) An important element of the grid as listed at Clause (b) of this Regulation can be taken out of service only after prior clearance of the concerned RLDC, except under emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be. RLDC shall inform opening or removal of any such important element (s) of the regional grid to NLDC and to the concerned regional entities who are likely to be affected, as specified in the Detailed Operating Procedure of NLDC.”

6.2. **Comments have been received from WRPC and POSOCO.**

6.2.1. **WRPC** suggested that “RPCs” should also be included for intimation by RLDC.

6.2.2. **POSOCO** commented that the word “NLDC” shall be replaced with the word “RLDC/NLDC” at the end of this clause.

6.3. **Analysis and Decision**

6.3.1. The suggestions of WRPC and POSOCO have been accepted.

6.3.2. Regulation 29 (2) (c) of the 2023 Grid Code Regulations has been modified as follows:

“(c) An important element of the grid as listed at sub-clause (b) of this clause can be taken out of service only after prior clearance of the concerned RLDC, except in emergencies as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be. RLDC shall inform the opening or removal of any such important element (s) of the regional grid to NLDC<u>, the concerned</u> <u>RPCs</u> and the concerned regional entities who are likely to be affected, as specified in the Detailed Operating Procedure of <u>RLDC or NLDC</u>.”

7. System Security (Regulation 29 (2)(d))

7.1. **Commission's Proposal**

7.1.1. The Commission had proposed the following in Regulation 29 (2)(d) of the Draft Regulations:

"(d) In case of switching off or tripping of any of the important elements of the regional grid under emergency conditions or otherwise, it shall be intimated immediately by the users with available details (i) to SLDC if the element is within the control area of SLDC, who in turn shall intimate the concerned RLDC and (ii) to RLDC if the element is within the control area of RLDC. The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within half an hour. The concerned RLDC or SLDC and the users shall ensure restoration of such elements within the estimated time of restoration as intimated."

7.2. **Comments have been received from SRPC, SJVNL, and Power Grid.**

7.2.1. **SRPC** suggested adding the following for bidirectional flow of information at the end of the provision at (ii) as "who in turn will intimate to the SLDC concerned."

7.2.2. **SJVNL** requested to increase the intimation time from half an hour to one hour.

7.2.3. **Power Grid** suggested increasing the intimation time from half an hour to one day.

7.3. **Analysis and Decision**

7.3.1. Suggestions of SRPC have been accepted. Suggestions to increase the time of intimation have not been accepted.

7.3.2. Regulation 29 (2) (d) of the 2023 Grid Code Regulations have been modified as follows:

"(d) In case of switching off or tripping of any of the important elements of the regional grid under emergency conditions or otherwise, it shall be intimated immediately by the users with available details (i) to SLDC if the element is within the control area of SLDC, who in turn shall intimate the concerned RLDC and (ii) to RLDC if the element is within the control area of RLDC, who in turn will intimate the concerned SLDC(s). The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within half an hour. The concerned RLDC or SLDC and the users shall ensure restoration of such elements within the estimated time of restoration as intimated."

8. System Security (Regulation 29 (2)(e))

8.1. **Commission's Proposal**

8.1.1. The Commission had proposed the following in Regulation 29 (2)(e) of the Draft Regulations:

"(e) The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. The restoration process shall be supervised by RLDC, in co-ordination with NLDC and concerned SLDC(s) in accordance with system restoration procedures of NLDC and RLDC(s)"

8.2. **Comments have been received from POSOCO**

8.2.1. **POSOCO** suggested replacing "RLDC" with "concerned LDC", and suggested adding "SLDC/RLDC" along with NLDC for coordination for restoration process.

8.3. **Analysis and Decision**

8.3.1. Suggestions of POSOCO have been accepted. Regulation 29 (2) (e) of the 2023 Grid Code Regulations has been modified as follows:

"(e) The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. The restoration process shall be supervised <u>by the concerned Load Despatch Centre,</u> in coordination with NLDC, concerned RLDC(s) and SLDC(s) in accordance with the system restoration procedures of NLDC and RLDC(s)."

9. System Security (Regulation 29 (3))

9.1. Commission's Proposal

9.1.1. The Commission had proposed the following in Regulation 29 (3) of the Draft Regulations:

"(3) Maintenance of grid elements shall be carried out by the respective users, transmission licensees, STUs and CTU in accordance with the provisions of the Central Electricity Authority (Grid Standards) Regulations, 2010. Outage of any element which is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be monitored by the concerned RLDC. RLDC shall report such outages to RPC and RPC shall issue suitable instructions to restore such elements in a specified time period."

9.2. Comments have been received from CTU, POSOCO

9.2.1. **CTU** commented that as CTU is not tasked with carrying out maintenance of Grid Elements, the word CTU needs to be removed from this provision.

9.2.2. **POSOCO** suggested replacing "Outage of any element" with "Prolonged non-availability/outage of any element under planned or forced outage beyond the approved duration/outage schedule" in the clause. POSOCO also suggested adding "as and when required" in reporting of outages by RLDC to RPC.

9.3. Analysis and Decision

9.3.1. CTU, STU, and transmission licensees are already covered under 'users', and hence the specific reference to them is deleted.

9.3.2. Further outages that are likely to cause danger are to be monitored as per the Regulation. Hence outages that have been approved for a particular duration are automatically monitored for their timely revival.

9.3.3. Regulation 29 (3) of the 2023 Grid Code Regulations has been modified as follows:

"(3) Maintenance of grid elements shall be carried out by the respective users in accordance with the provisions of the CEA Grid Standards. Outage of an element that is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be monitored by the concerned RLDC. RLDC shall report such outages to RPC and RPC shall issue suitable instructions to restore such elements in a specified time period."

10. System Security (Regulation 29 (4))

10.1. Commission's Proposal

10.1.1. The Commission had proposed the following in Regulation 29 (4) of the Draft Regulations:

"(4) Except under an emergency, or when it becomes necessary to prevent an imminent damage to a costly equipment, no user shall suddenly reduce its generating unit output by more than 100 (one hundred) MW [20 (twenty) MW in case of NER] without prior permission of the respective RLDC."

10.2. **Comments have been received from KSEBL and Sembcorp**

10.2.1. **KSEBL** commented that the change in generation should not be limited to figures like 100 MW, but specified as a percentage change in the output of the generation with respect to the duration that variation persists in the grid.

10.2.2. **Sembcorp** suggested that this clause should not be applicable to wind and solar generators.

10.3. **Analysis and Decision**

10.3.1. The clause has been retained in the 2023 Grid Code, considering that sudden changes may lead to grid security issues. Accordingly, linking it to percentage change of output is not accepted since percentage output would vary depending on the size of the generation unit, whereas the limit should be specified in maximum MW terms.

10.3.2. Since the issue is related to grid security, the same shall be applicable to all generating units, including wind and solar. However, it is clarified that any changes in the output of wind /solar due to sudden cloud cover or due to variation in wind speed shall not be considered attributable to the user.

10.3.3. The word 'costly equipment' has been replaced with the word 'critical equipment' and Regulation 29 (4) of the 2023 Grid Code Regulations has been modified as follows:

"(4) Except in an emergency, or when it becomes necessary to prevent imminent damage to <u>critical equipment</u>, no user shall suddenly reduce its generating unit output by more than 100 (one hundred) MW [20 (twenty) MW in the case of NER] without prior permission of the respective RLDC."

11. System Security (Regulation 29 (5))

11.1. **Commission's Proposal**

11.1.1. The Commission had proposed the following in Regulation 29 (5) of the Draft Regulations:

"(5) Except under an emergency, or when it becomes necessary to prevent an imminent damage to a costly equipment, no user shall cause a sudden variation in its load by more than 100 (one hundred) MW without prior permission of the respective RLDC."

11.2. **Comments have been received from SRPC, AP Transco, PCKL, KPTCL, TS Transco, WBSEDCL, Torrent Power Limited, and Tata Power**

11.2.1. **SRPC** commented that if the regional entity is managing the demand and generation with its internal resources and is not passing the impact to the regional grid, it should be allowed for load variation. Further, in 10 seconds, most tripping related oscillations settle down. Accordingly, SRPC suggested the following modification in this provision:

"Except under an emergency, or when it becomes necessary to prevent an imminent damage to a costly equipment, no regional entity shall cause a sudden variation in ISTS drawal by more than 100 (one hundred) MW in 10 seconds without prior permission of the respective RLDC".

11.2.2. **AP Transco**, **KSEBL**, **PCKL,** and **KPTCL** commented on Regulation 29(4) and 29(5) that this particular clause of the regulation has no relevance and is ambiguous as "suddenly reduced" is not defined and during real time operation it might be misinterpreted in many ways. AP Transco also mentioned that taking prior permission for 100 MW continuous variation (at least forty switching operations will be done per day in Sileru complex and Srisailam power house) is difficult and has no advantage in operation.

11.2.3. **TS TRANSCO**, **WBSEDCL**, **AP Transco,** and **KPTCL** commented that there is a likely variation of more than 100 MW from RE sources. To handle large variations from RE, switching operations of Hydel Stations are being carried out to ensure Load Generation balance in the control area with minimum deviations from the Grid.

11.2.4. **Torrent Power Limited** commented to delete the clause, as for Distribution licenses the variability in demand is beyond its control, which is further aggravated due to the increasing penetration of solar rooftops.

11.2.5. **Tata Power** commented that it may not be practical to seek prior consent from respective RLDC for the aforementioned sudden load variation, in such cases Discoms/State Load Dispatch centres may take a call on the same based on the prevailing conditions with due intimation to the respective RLDC.

11.3. **Analysis and Decision**

11.3.1. It is clarified that sudden changes covered under this clause are at the ISTS periphery and not internal changes which are managed internally without affecting the drawal/injection at the ISTS periphery. Further, the clause is retained since entities should endeavour to make the changes in drawal/injection into the ISTS as slow changes so that grid is operated in secure manner.

11.3.2. The word 'costly equipment' has been replaced with the word 'critical equipment', and Regulation 29 (5) of the 2023 Grid Code Regulations has been modified as follows:

"(5) Except in an emergency, or when it becomes necessary to prevent imminent damage to critical equipment, no user shall cause a sudden variation in its load by more than 100 (one hundred) MW without the prior permission of the respective RLDC."

12. System Security (Regulation 29 (6))

12.1. **Commission's Proposal**

12.1.1. The Commission had proposed the following in Regulation 29 (6) of the Draft Regulations:

"(6) All generating units shall have their automatic voltage regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers and any other requirement in operation, as per CEA Technical Standards for Connectivity. If a generating unit with capacity higher than 50 (fifty) MW is required to be operated without its AVR in service, the generating station shall immediately intimate to the concerned

RLDC along with the reasons thereof and the likely duration of such operation and obtain its permission."

12.2. **Comments have been received from SRPC, WRPC and POSOCO**

12.2.1. **SRPC** suggested changing the capacity from 50 MW to 100 MW (intimation to RLDC for operation without AVR) in line with the CEA Connectivity Standards.

12.2.2. **WRPC** suggested including the sentence "and the PSS Tuning guidelines as issued by NPC/CEA from time to time" after "CEA Technical Standards for Connectivity" and to include RPC also along with RLDC for intimation by generating stations in case of operation without AVR. Further, WRPC commented that NPC of CEA may develop a common procedure for tuning these devices so that there is uniformity of procedures in all India grid.

12.2.3. **POSOCO** commented that CEA Technical standards do not mention PPC as of now. However, RE plants need PPC and it has to be tuned at regular intervals. Accordingly, POSOCO suggested adding "Power Plant Controller (PPC) for REGS as a requirement in operation and "PSS/PPC" along with AVR.

12.3. **Analysis and Decision**

12.3.1. Suggestions of SRPC have been accepted, and 50 MW has been replaced with 100 MW.

12.3.2. WRPC suggestions to make guidelines for PSS tuning at the RPC level may be taken up by RPCs from time to time in the interest of the Grid. RLDCs may share information about generators operating without AVR with RPCs.

12.3.3. Keeping in view the suggestions of POSOCO, PPC has been inserted in the clause.

12.3.4. Regulation 29 (6) of the 2023 Grid Code Regulations has been modified as follows:

"(6) All generating units shall have their automatic voltage regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers (<u>Power Plant Controller</u>) and any other requirements in operation, as per the CEA Technical Standards for Connectivity. If a generating unit with a capacity higher than 100 (hundred) MW is required to be operated without its AVR or voltage controller in service, the generating station shall immediately inform the concerned RLDC of the reasons thereof and the likely duration of such operation and obtain its permission."

13. System Security (Regulation 29 (7))

13.1. **Commission's Proposal**

13.1.1. The Commission had proposed the following in Regulation 29 (7) of the Draft Regulations:

"(7) The tuning, including for low and high voltage ride through capability of wind and solar generators or any other requirement as per CEA Technical Standards for Connectivity shall be carried out:

– *at least once in every five (5) years;*

– *based on operational feedback provided by the RLDC after analysis of a grid event or disturbance; and*

– in case of a major change in excitation system or major network changes or fault level changes near the generating plant as reported by NLDC or RLDC(s), as the case may be"

13.2. **Comments have been received from Shri Zakir H Rather and POSOCO**

13.2.1. **Shri Zakir H Rather (associate Prof IIT Bombay)** commented that the Indian grid code requires RE plants to comply with LVRT for a single voltage dip. However, it is pretty much possible that there can be recurrent voltage events experienced in the grid. In the interest of overall grid stability, it is recommended that LVRT compliance against recurrent faults should be considered in IEGC 2022. The Grid code regulation across the developed RE rich countries clearly specifies the reactive current requirement with respect to the retained voltage at PCC. Therefore, it is recommended that a clear requirement of reactive current injection priority during the LVRT period should be specified.

13.2.2. **POSOCO** commented that RE generating stations have a Power Plant Controller (PPC) for regulation of generation. Therefore, it is suggested that the IEGC should mandate a review of the settings of PPC and its tuning at regular intervals. Several incidents of loss of RE generation due to improper relay coordination have been experienced. Further, Excitation system changes are the generators' responsibility, hence it may also be added. Accordingly, POSOCO suggested adding "of AVR, PSS, Voltage Controllers, PPC" after "The tuning" and suggested deleting the words "a major change in excitation system or" and adding a new provision in this clause:

'– *<u>in case of major change in excitation system as reported by the generating plant</u>.'*

13.3. **Analysis and Decision**

13.3.1. With respect to suggestions of Shri Zakir H Rather, it is clarified that requirements of LVRT /HVRT shall be as per relevant CEA Standards. Further, the suggestions of POSOCO have been accepted, and tuning of AVR, PSS, Voltage Controller (PPC) has been inserted.

13.3.2. Regulation 29 (7) of the 2023 Grid Code Regulations has been modified as follows:

"(7) The tuning of <u>AVR, PSS, Voltage Controllers (PPC)</u> including for low and high voltage ride through capability of wind and solar generators or any other requirement as per CEA Technical Standards for Connectivity shall be carried out by the respective generating station:
– at least once every five (5) years;
– based on operational feedback provided by the RLDC after analysis of a grid event or disturbance; and
– in case of major network changes or fault level changes near the generating station as reported by NLDC or RLDC(s), as the case may be.
<u>– in case of a major change in the excitation system of the generating station</u>."

14. System Security (Regulation 29 (8))

14.1. **Commission's Proposal**

14.1.1. The Commission had proposed the following in Regulation 29 (8) of the Draft

Regulations:

"(8) Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the concerned RPC. In case the tuning is not complied with as per the plan and procedure, the concerned RPC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the generating unit may be disconnected from the grid by the concerned RLDC on receipt of intimation to that effect from the concerned RPC".

14.2. **Comments have been received from SRPC and POSOCO.**

14.2.1. **SRPC** suggested that RPC should be substituted by RLDC as RPC is a Statutory body, and disconnection of the Generating Unit is not defined in its functions. RLDC is defined in the EA Act with more power on such issues.

14.2.2. **POSOCO** commented that the words "Power Plant Controller (PPC) of wind/solar plants" may be inserted after the words "AVRs of generating units," in this clause.

14.3. **Analysis and Decision**

14.3.1. The suggestion of SRPC has been considered and accordingly 'disconnection' has been replaced with appropriate action under Section 29 of the Act by RLDC.

14.3.2. Tuning of PPC is covered under clauses (6), (7) of Regulation 29 and also covered under this Clause under 'reactive power controller'.

14.3.3. Regulation 29 (8) of the 2023 Grid Code Regulations has been modified as follows:

"(8) Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the concerned RPC. In case the tuning is not complied with as per the plan and procedure, the concerned RLDC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the concerned RLDC may approach the Commission under Section 29 of the Act."

15. System Security (Regulation 29 (9))

15.1. **Commission's Proposal**

15.1.1. The Commission had proposed the following in Regulation 29 (9) of the Draft Regulations:

"(9) Provisions of protection and relay settings shall be coordinated periodically throughout the regional grid, as per plan finalized by the respective RPC in accordance with the Protection, Testing and Commissioning Code of these regulations"

15.2. **Comments have been received from SRPC, HPSLDC, WRPC, and POSOCO.**

15.2.1. **SRPC** suggested deleting this clause as the same is covered under the Protection Code.

15.2.2. **HPSLDC** suggested that the periodicity of coordination should be 06 months for all Substations and transmission lines of 132 kV and above voltage level and 12 months for 66 kV and below voltage levels.

15.2.3. **WRPC** suggested including provision under this clause for the formulation of working group/s in the region involving protection and study engineers of the utilities in the region.

15.2.4. **POSOCO** suggested inserting the words "(including for wind and solar plants)" after the words "protection and relay settings"

15.3. **Analysis and Decision**

15.3.1. The Regulation covers various aspects of 'System Security' and accordingly protection and relay settlings are retained with cross reference to Protection Code. The Commission has noted the suggestions of the stakeholders.

15.3.2. With regard to suggestions of HPSLDC and POSOCO, the requirements may be finalised at the RPC level in accordance with provisions of the Protection Code of the 2023 Grid Code.

15.3.3. The provision as proposed in the Draft Regulations has been retained.

16. System Security (Regulation 29 (10))

16.1. **Commission's Proposal**

16.1.1. The Commission had proposed the following in Regulation 29 (10) of the Draft Regulations:

"(10) RPCs shall prepare the islanding schemes in accordance with Central Electricity Authority (Grid Standards) Regulations, 2010 for identified generating stations, cities and locations and ensure its implementation. The islanding schemes shall be reviewed and augmented depending on assessment of critical loads at least once in 3 (three) years".

16.2. **Comments have been received from SRPC and WRPC.**

16.2.1. **SRPC** suggested decreasing the time line to review and augmentation of Islanding Scheme from at least once 3 years to once a year or whenever required. It is also suggested including a provision that the concerned entities would complete the scope of work on their equipment/element within 6 months of finalization by RPC.

16.2.2. **WRPC** commented that changes in network configuration/Load/generation within or around the Island jurisdictions are being monitored by SLDCs/RLDCs, and therefore, any changes in and around the Island jurisdiction is required to be brought to the notice of RPCs for reviewing it.

16.3. **Analysis and Decision**

16.3.1. Considering suggestions of SRPC, a timeline of review has been reduced from 3 years to 1 year or earlier, as required. While reviewing/assessing the Islanding schemes, necessary data shall be provided by all users including RLDCs.

16.3.2. Regulation 29 (10) of the 2023 Grid Code Regulations has been modified as follows:

"(10) RPCs shall prepare the islanding schemes in accordance with the CEA Grid Standards for identified generating stations, cities and locations and ensure their implementation. The islanding schemes shall be reviewed and augmented depending on the assessment of critical loads <u>at least once a year or earlier, if required</u>."

17. System Security (Regulation 29 (11))

17.1. **Commission's Proposal**

17.1.1. The Commission had proposed the following in Regulation 29 (11) of the Draft Regulations:

"(11) Mock drill of the islanding schemes shall be carried out annually by the respective RLDCs in coordination with the concerned SLDCs and other users involved in the islanding scheme".

17.2. **Comments have been received from SRPC, WRPC and POSOCO**

17.2.1. **SRPC** and **WRPC** commented that a physical Mock Drill of the Islanding scheme may not be possible since the system frequency cannot be lowered to the trigger frequency set for Islanding schemes. SRPC suggested including the provision for "study simulations" in place of "Mock drill" of the Islanding Scheme and it can be study based only.

17.2.2. **POSOCO** suggested that the IEGC may allow mock drills of islanding schemes through simulations in cases where frequent field trials are infeasible.

17.3. **Analysis and Decision**

17.3.1. Considering suggestions of SRPC, WRPC, and POSOCO, simulation testing has been added for cases where filed testing is not possible.

17.3.2. Regulation 29 (11) of the 2023 Grid Code Regulations has been modified as follows:

"(11) Mock drill of the islanding schemes shall be carried out annually by the respective RLDCs in coordination with the concerned SLDCs and other users involved in the islanding scheme. <u>In case mock drill with field testing is not possible to be carried out for a particular scheme, simulation testing shall be carried out by the respective RLDC</u>."

18. System Security (Regulation 29 (12))

18.1. **Commission's Proposal**

18.1.1. The Commission had proposed the following in Regulation 29 (12) of the Draft Regulations:

"(12) All distribution licensees, STUs and bulk consumers shall provide automatic under-frequency relays (UFR) and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in grid failure as per the plan given by the RPCs from time to time. The default UFR settings shall be as specified in Table-2 below:

Table 2: Default UFR Settings

Sr. No.	*Stage of UFR Operation*	*Frequency (Hz)*
1	*Stage-1*	*49.40*
2	*Stage-2*	*49.20*
3	*Stage-3*	*49.00*
4	*Stage-4*	*48.80*
Note 1: All states (or STUs) shall plan UFR settings and df/dt load shedding schemes depending on their local load generation balance in coordination with and approval of the concerned RPC. Note 2: Pumped storage hydro plants operating in pumping mode or ESS operating in charging mode shall be automatically disconnected before the first stage of UFR.		

The load shedding for each Stage of UFR operation, in percentage of demand or MW shall be as finalised by the respective RPCs.”

18.2. **Comments have been received from CESC, WBSEDCL, SLDC Odisha, DVC, WRPC, and POSOCO.**

18.2.1. **CESC** commented that Automatic under frequency relays and df/dt relays are not required at the same time, so, the term “and” can be deleted from this provision.

18.2.2. **WBSEDCL** commented that the inclusion of old machines like the Purulia Pump Storage Project (PPSP), designed with the aid of Japanese technology, running out of warranty and with the guidance of TOSHIBA, under the preview of automatic tripping may be risky as far as the machine health & age are concerned & should be avoided for the greater interest of the Grid.

18.2.3. **SLDC Odisha** commented that the grid has become stable, and it is rare that the frequency goes below 49.4Hz, so it is irrelevant to set it from 49.4Hz. It should start at 49.6Hz. Moreover, most states have implemented ADMS, which takes stage-1 load shedding from 49.9Hz.

18.2.4. **DVC** commented that since DVC’s feeders mostly supply power to the Steel industries, traction, and coal mines, with few domestic feeders supplying to JBVNL and identification of specific feeders under different schemes, namely, Demand Response, UFR & df/dt scheme, may not be possible in respect to DVC, also the spatial spread of feeders may not be feasible due to concentration of most of the Distribution feeders across Jharkhand area. DVC requested to consider the same while finalizing the Load Relief Quantum in respect of the DVC state.

18.2.5. **WRPC** suggested adding *‘The UFR settings and region wise load shedding quantum shall be decided by NPC in consultation with the stakeholders.’*

18.2.6. **POSOCO** commented that NPC is already coordinating the common procedure of UFR settings; the same can be continued for uniform implementation of the settings by RPCs in all the regions. This is required in view of changing scenarios with RE penetration which may need periodic review of system security aspects. Further, default settings for load shedding have also been included, as suggested by the Expert Group Report 2020, which will help in the uniform implementation of the settings. Accordingly, the following modification is suggested:

“All distribution licensees, STUs, and bulk consumers shall provide automatic under-frequency relays (UFR) and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in grid failure as per the plan given by <u>NPC in coordination with NLDC and RPCs</u> <u>after detailed studies</u> RPCs from time to time. The default UFR settings shall be as specified in Table-2 below:

Table 2: Default UFR Settings

Sr. No.	Stage of UFR Operation	Frequency (Hz)	**Default Setting**
1	Stage-1	49.40	**6%**
2	Stage-2	49.20	**6%**

Sr. No.	Stage of UFR Operation	Frequency (Hz)	**Default Setting**
3	Stage-3	49.00	**6%**
4	Stage-4	48.80	**7%**
~~Note 1: All states (or STUs) shall plan UFR settings and *df/dt* load shedding schemes depending on their local load generation balance in coordination with and approval of the concerned RPC.~~ Note 2: Pumped storage hydro plants operating in pumping mode or ESS operating in charging mode shall be automatically disconnected before the first stage of UFR.			

~~The load shedding for each Stage of UFR operation, in percentage of demand or MW shall be as finalised by the respective RPCs.~~"

18.3. **Analysis and Decision**

18.3.1. The suggestions of CESC to keep UFR and df/dt as optional is not accepted as both relays serve different purposes and are required depending on the event.

18.3.2. With respect to suggestions of WBSEDCL to keep Purulia exempted from automatic disconnection in case of a grid event, it is clarified that the regulation clauses are applicable to all the referred entities, and if any specific exemption by an entity due to technical difficulty is being sought may be taken up separately.

18.3.3. With regard to suggestion of SLDC Odisha to start UFR at 49.6, it is clarified that settings have been included in the 2023 Grid Code as finalised by all RPCs at NPC. In case the need is felt to start it at 49.6, the same needs to be agreed upon uniformly at all RPCs.

18.3.4. With regard to suggestions of DVC and WRPC, it is clarified that specific details of the scheme will be finalised at RPC.

18.3.5. The suggestions of POSOCO to include default settings as 6% is not accepted as default settings may vary from State to State, and specifics must be decided at the RPC level in consultation with all concerned.

18.3.6. The provision as proposed in the Draft Regulations has been retained.

19. System Security (Regulation 29 (13)(b))

19.1. **Commission's Proposal**

19.1.1. The Commission had proposed the following in Regulation 29 (13)(b) of the Draft Regulations:

"(b) Demand disconnection shall not be set with any time delay in addition to the operating time of the relays and circuit breakers".

19.2. **Comments have been received from UPSLDC**

19.2.1. **UPSLDC** commented that, as observed through PMU data during oscillation in frequency, df/dt (Rate of Change of Frequency) crosses the existing threshold of 0.1Hz/sec for a short duration. Therefore, there should be either uniform an inherent delay in the df/dt relay operation, or the sampling interval of the df/dt relay should be such that it does not result in its operation during frequency oscillations.

19.3. **Analysis and Decision**

19.3.1. The specific settings may be finalised at RPC as per provisions under the Protection Code.

19.3.2. The provision as proposed in the Draft Regulations has been retained.

20. System Security (Regulation 29 (13)(e))

20.1. **Commission's Proposal**

20.1.1. The Commission had proposed the following in Regulation 29 (13)(e) of the Draft Regulations:

"(e) RPC shall undertake monthly review of UFR and df/dt scheme and also carry out random inspection of the under-frequency relays. RPC shall publish such monthly review along with exception report on its website".

20.2. **Comments have been received from POSOCO.**

20.2.1. **POSOCO** suggested adding the words "with an intimation to CERC" at the end of this clause. Further, suggested adding one new subclause (f) as below under Regulation 29(13):

"(f) SLDCs shall report the UFR and df/dt operation and load relief to RLDCs/NLDC and publish the report on its website with an intimation to SERC."

20.3. **Analysis and Decision**

20.3.1. With regard to sending exception reports to CERC, it is clarified that in case RPC brings any specific exceptions for the information of Commission with specific actionable points, the same can be forwarded by RPC on a case to case basis.

20.3.2. Further considering suggestions of POSOCO, the Commission has added new clause 29 (13) (f) in the 2023 Grid Code Regulations as follows,

"(f) SLDC shall report the actual operation of UFR and df/dt schemes and load relief to the concerned RLDCs and RPCs and publish the monthly report on its website."

21. System Security (Regulation 29 (15))

21.1. **Commission's Proposal**

21.1.1. The Commission had proposed the following in Regulation 29 (15) of the Draft Regulations:

"(15) NLDC, RLDCs, SLDCs, CTU, STUs and users shall operate in a manner to ensure that the steady state grid voltage as per the Central Electricity Authority (Grid Standards) Regulations, 2010 remains within the following operating range:

TABLE 3: VOLTAGE RANGE

Voltage (kV rms)		
Nominal	***Maximum***	***Minimum***
765	*800*	*728*
400	*420*	*380*
220	*245*	*198*
132	*145*	*122*
110	*121*	*99*
66	*72*	*60*
33	*36*	*30*

21.2. **Comments have been received from CTU, Power Grid and POSOCO**

21.2.1. **CTU** suggested removing the terms CTU and STUs as they are only planning agencies and not involved in grid operation. Further, CTU suggested that the 230kV voltage level may also be introduced.

21.2.2. **Power Grid** suggested that the word "Users" be deleted as voltage maintenance is under the control of NLDC, RLDC, and SLDCs.

21.2.3. **POSOCO** suggested Operating range for the 230 kV system and 110 kV systems may be included exclusively as several states like Tamil Nadu and Maharashtra have transmission systems at 230 kV and 110 kV, respectively.

21.3. **Analysis and Decision**

21.3.1. The terms CTU and STU have been deleted since they are covered under 'users'. The suggestion of Power Grid to remove 'users' is not accepted since it is the responsibility of users to take appropriate measures to maintain voltage as per requirements of the CEA Technical Standards and must be complied with.

21.3.2. Voltage levels of 230 kV have been inserted as suggested by POSOCO and as included in the CEA Manual on Transmission Planning Criteria.

21.3.3. Regulation 29 (15) of the 2023 Grid Code Regulations has been modified as follows:

"(15) NLDC, RLDCs, SLDCs, and users shall operate in a manner to ensure that the steady state grid voltage as per the CEA Grid Standards remains within the following operating range:

TABLE 3: VOLTAGE RANGE

Voltage (kV rms)		
Nominal	***Maximum***	***Minimum***
765	*800*	*728*
400	*420*	*380*
*230**	*245**	*207**
220	*245*	*198*
132	*145*	*122*
110	*121*	*99*
66	*72*	*60*
33	*36*	*30*

** As per CEA Manual on Transmission Planning Criteria, 2023."*

22. System Security (Regulation 29 (17))

22.1. **Commission's Proposal**

22.1.1. The Commission had proposed the following in Regulation 29 (17) of the Draft Regulations:

"(17) Transmission licensees and distribution licensees shall implement defense mechanisms as finalized by the respective RPCs to prevent voltage collapse and cascade tripping".

22.2. **Comments have been received from SRPC, and POSOCO**

22.2.1. **SRPC** suggested substituting the words "All Users" for "Transmission licensees and distribution licensees".

22.2.2. **POSOCO** suggested adding one more sub-regulation (18) as below under Regulation 29 "System Security":

"(18) All defense mechanisms, viz., islanding schemes, UFR, df/dt relays and SPS shall be always in operation and any exception shall immediately be intimated to the concerned SLDC/RLDC along with the reasons thereof and the likely duration of such exception and obtain its permission."

22.3. **Analysis and Decision**

22.3.1. The suggestions of SRPC and POSOCO have been accepted.

22.3.2. Regulation 29 (17) of the 2023 Grid Code Regulations has been modified, and new Clause (18) has been inserted as follows:

"(17) The concerned users shall implement defence mechanisms as finalized by the respective RPCs to prevent voltage collapse and cascade tripping.
(18) All defense mechanisms shall always be in operation and any exception shall be immediately intimated by the concerned user to the concerned RLDC and SLDCs along with the reasons and the likely duration of such exception. The concerned user shall also obtain permission from the concerned RLDC or SLDC, as applicable."

23. Frequency Control and Reserves (Regulation 30 (1))

23.1. **Commission's Proposal**

23.1.1. The Commission had proposed the following in Regulation 30 (1) of the Draft Regulations:

"(1) The National Reference Frequency shall be 50.000 Hz and shall be measured with a resolution of +/-0.001 Hz. The frequency data measured at every second shall be archived by RLDCs".

23.2. **Comments have been received from SRPC, Adani Power and APP**

23.2.1. **SRPC** suggested reducing the decimal points to two digits instead of three digits for the National Reference Frequency and its resolution.

23.2.2. **Adani Power** and **APP** commented that as the present energy meters have resolution of 0.01 Hz, and the entire NPC format is required to be changed, the Commission should decide on a compensation mechanism for the replacement of interface meters.

23.3. **Analysis and Decision**

23.3.1. It is clarified that POSOCO measures the frequency with an accuracy of three decimal points, and accordingly, the same is retained. Further, the individual energy meters installed by entities may have resolution as per CEA Standards and the need for replacement arises when the same is required as per CEA Standards.

23.3.2. Regulation 30 (1) of the 2023 Grid Code Regulations has been modified to add the allowable band of frequency as follows:

"(1) The National Reference Frequency shall be 50.000 Hz, <u>and the allowable band of frequency shall be 49.900-50.050 Hz</u>. The frequency shall be measured with a resolution of +/-0.001 Hz <u>by NLDC, RLDCs, and SLDC,</u> and such frequency data measured every second shall be archived by RLDCs."

24. Frequency Control and Reserves (Regulation 30 (2))

24.1. **Commission's Proposal**

24.1.1. The Commission had proposed the following in Regulation 30 (2) of the Draft Regulations:

"(2) The NLDC, RLDC and SLDC shall ensure that the grid frequency remains close to 50 Hz. and ensure that the frequency is restored within the allowable band of 49.95-50.05 Hz at the earliest".

24.2. **Comments have been received from KSEBL, TS Transco, HPSEBL, PSPCL, MSEDCL and POSOCO**

24.2.1. **KSEBL** commented that even during low frequencies, even if the entity is under drawing for the last 6 time blocks, a part of sign change in drawal has to be done. During such an operation, while enforcing the DSM regulation, this action causes the frequency to deteriorate further. Also, the same is the case while exporting when frequency is above 50Hz, Unless and until there is a change in the DSM regulation, this clause w.r.t. SLDC cannot be implemented, even if SLDC wants to.

24.2.2. **TS TRANSCO** suggested that the existing operating frequency band may be continued till the establishment of automation features in the state control area for load generation balancing.

24.2.3. **HPSEBL** suggested that the frequency range should be kept somewhat higher and frequency range squeezing be done in steps.

24.2.4. **PSPCL** suggested that while fixing the frequency band, it may please be considered that the new Ancillary service and DSM mechanism have yet to be operationalized and their impact on the system operation and impact on the cost of power procurement by Discoms due to reserves may please be analysed first.

24.2.5. **MSEDCL** commented that the frequency band is 49.90 to 50.05 Hz which is very well proven to be a safe band for the grid and requested to continue with the same frequency band of 49.90-50.05 Hz.

24.2.6. **POSOCO** suggested that, as mentioned in the Expert Group Report, 2020 the sentence "and ensure that the frequency is restored within the allowable band of 49.95-50.05 Hz at the earliest" may be replaced with the sentence "All possible endeavours shall be made by NLDC, RLDCs and SLDCs to restore the frequency in the allowable band of 49.95-50.05 Hz within fifteen (15) minutes of the start of excursion beyond the band."

24.3. **Analysis and Decision**

24.3.1. Considering the suggestions of stakeholders, the frequency band has been retained as in the 2010 Grid Code from 49.900-50.050 Hz. Further, the provision of sign change has been removed from DSM Regulations.

24.3.2. The suggestions of POSOCO to include timeline of 15 minutes is rejected since the action of restoration starts through primary response and secondary response immediately on occurrence of event. The endeavour should be to keep the frequency within the band all times.

24.3.3. Regulation 30 (2) of the 2023 Grid Code Regulations has been modified as follows:

"(2) The NLDC, RLDC and SLDC shall endeavour that the grid frequency remains close to 50.000 Hz and in case frequency goes outside the allowable band, ensure that the frequency is restored within the allowable band of 49.900-50.050 Hz at the earliest."

25. Frequency Control and Reserves (Regulation 30 (3))

25.1. **Commission's Proposal**

25.1.1. The Commission had proposed the following in Regulation 30 (3) of the Draft Regulations:

"(3) All users shall adhere to their schedule of injection or drawl, as the case may be, and take such action as required under these regulations and as directed by NLDC or respective RLDCs or respective SLDCs so that the grid frequency is maintained and remains within the allowable band."

25.2. **Comments have been received from AP Transco, KSEBL, and KPTCL**

25.2.1. **AP Transco** commented that under Ancillary Service Regulations, the responsibility of ensuring frequency is on SLDC, RLDC, and NLDC with a direction to maintain reserve ancillaries at all levels. Specific operating procedures may be required to decide whether SLDC / RLDC or NLDC should take action to avoid simultaneous multiple actions.

25.2.2. **KSEBL** commented that the present Regulation should foresee the instances in the grid while the entity is still in the under drawal mode and the frequency of the grid is lower. In this case, to improve the frequency, the entity will be asked by RLDC to put in more reserves (hydro reserves w.r.t. Kerala), but this might exceed the 12% of schedule and will have a commercial impact on the entity. Hence while taking steps to improve frequency, the ACE will be showing a high deviation.

25.2.3. **KPTCL** commented that keeping frequency within the band and maintaining area control error (deviation) by SLDC within the limit may require counter actions like frequency correction, this would require, on the one hand, SLDC to under draw to maintain the frequency, whereas, on the other hand, it may have to overdraw to reduce the deviation in ACE (DSM regulation-2022 not linked with frequency). Hence SLDC cannot be held responsible to ensure both frequency between the band and deviation within the limits. In the present deviation regulation, SLDC would get penalised if it tries to maintain the frequency within the IEGC range.

25.3. **Analysis and Decision**

25.3.1. The requirement put forth in the Regulation is that all users should adhere to their schedule so that frequency remains close to the reference frequency. On the occurrence of any event, the reserves shall be kicked in to bring the frequency close to the reference frequency. Further, if NLDC/RLDC directs a user to take certain actions in the interest of grid security, such direction would be incorporated into the schedule and would not lead to any penalty.

25.3.2. It is clarified that under the framework of reserves, the all India reserve requirement has been divided into reserves to be maintained at the State level by SLDC and those to be maintained at regional level by RLDC/NLDC, so that overall the reserve requirement on an all India basis is met.

25.3.3. The provision as proposed in the Draft Regulations has been retained.

26. Frequency Control and Reserves (Regulation 30 (4)(a)(iii) and (iv))

26.1. **Commission's Proposal**

26.1.1. The Commission had proposed the following in Regulation 30 (4)(a)(iii) of the Draft Regulations:

"(iii) Secondary reserves including automatic generation control and demand response shall be deployed by a control area as per these regulations or the Ancillary Services Regulations, as the case may be.

(iv) Tertiary reserves shall be deployed by a control area as per these regulations or the Ancillary Services Regulations, as the case may be."

26.2. **Comments have been received from SRPC and POSOCO**

26.2.1. **SRPC** suggested including the provision of deployment of Secondary reserves as per the SERCs Ancillary Services Regulations/Grid code also in this clause.

26.2.2. **POSOCO** suggested that the "demand response" may be deleted from Secondary reserves and included under Tertiary Reserve as the expected time of demand response suits tertiary response, and automation of demand response may not be practical in India.

26.3. **Analysis and Decision**

26.3.1. The suggestions of SRPC have been accepted, and accordingly "*or the respective regulations on Ancillary Services of the State*" has also been referred to in the Clause.

26.3.2. With regard to suggestions of POSOCO, it is clarified that demand response may be deployed if it is able to adhere to the response time required under secondary response.

26.3.3. Regulation 30 (4)(a)(iii) of the 2023 Grid Code Regulations have been modified as follows:

"(iii) Secondary reserves including automatic generation control and demand response shall be deployed by the control area as per these regulations or the Ancillary Services Regulations <u>or the respective regulations on Ancillary Services of the State</u>, as the case may be.
(iv) Tertiary reserves shall be deployed by the control area as per these regulations or the Ancillary Services Regulations <u>or the respective regulations on Ancillary Services of the State</u>, as the case may be."

27. Frequency Control and Reserves (Regulation 30 (4) (b))

27.1. **Commission's Proposal**

27.1.1. The Commission had proposed the following in Regulation 30 (4) (b) of the Draft Regulations:

"(b) Black Start reserves:
Generating stations having black start capability shall be identified by NLDC and RLDCs to act as black start reserves."

27.2. **Comments have been received from SECI, Wartsila, SRPC, POSOCO and Siemens Limited**

27.2.1. **SECI** and **Wartsila** suggested including ESS in this clause.

27.2.2. **SRPC** and **POSOCO** suggested including SLDC also to identify the stations having black start capability.

27.2.3. **Siemens Limited** suggested that HVDC stations based on a Voltage Sourced Converter (VSC) that offers black start capability to support grid restoration may be included.

27.3. **Analysis and Decision**

27.3.1. The suggestions of stakeholders have been accepted, and accordingly, Regulation 30 (4)(b) of the 2023 Grid Code Regulations have been modified as follows:

"(b) Black Start reserves:

Generating stations having black start capability, ESS and HVDC Station based on VSC shall be identified by NLDC and RLDCs in consultation with SLDC(s) at the inter-State level and by SLDC at the State level, to act as black start reserves."

28. Frequency Control and Reserves (Regulation 30 (4) (c))

28.1. **Commission's Proposal**

28.1.1. The Commission had proposed the following in Regulation 30 (4) (c) of the Draft Regulations

"(c) Voltage Control reserves:

Voltage Control reserves shall be deployed for controlling the voltage at a bus through reactive power injection or drawl."

28.1.2. **Comments have been received from POSOCO**

28.1.3. **POSOCO** suggested replacing the word "bus" with "bus/subsystem".

28.2. **Analysis and Decision**

28.2.1. The suggestions of POSOCO have been accepted.

28.2.2. Regulation 30 (4)(c) of the 2023 Grid Code Regulations has been modified as follows:

"(c) Voltage Control reserves:

Voltage Control reserves shall be deployed for controlling the voltage at a bus or sub-system through reactive power injection or drawl."

29. Frequency Control and Reserves (Regulation 30 (8))

29.1. **Commission's Proposal**

29.1.1. The Commission had proposed the following in Regulation 30 (8) of the Draft Regulations:

"(8) The primary response of the generating units shall be verified by the LDCs during grid events."

29.2. **Comments have been received from HPSLDC, POSOCO**

29.2.1. **HPSLDC** suggested that the timeline regarding verification needs to be mentioned.

29.2.2. **POSOCO** suggested adding the sentence "and the generators shall provide the required data to the LDCs within 2 days of notification of reportable event by NLDC" at the end of this clause.

29.3. **Analysis and Decision**

29.3.1. The timeline to verify the response by LDCs may be included in the respective Operating Procedure. Further suggestions of POSOCO have been accepted. Regulation 30 (8) of the 2023 Grid Code Regulations has been modified as follows:

"(8) The primary response of the generating units shall be verified by the Load Despatch Centres (LDCs) during grid events. <u>The concerned generating station shall furnish the requisite data to the LDCs within two days of notification of reportable event by the NLDC</u>."

30. Frequency Control and Reserves (Regulation 30 (9))

30.1. **Commission's Proposal**

30.1.1. The Commission had proposed the following in Regulation 30 (9) of the Draft Regulations:

"(9) Inertia:
The power system shall be operated at all the times with a minimum inertia to be stipulated by NLDC so that minimum nadir frequency post reference contingency stays above the threshold set for under frequency load shedding (UFLS). NLDC shall reschedule generation including curtailment of wind, solar and wind-solar hybrid generation, if required, in coordination with the respective RLDCs and SLDCs to maintain the minimum inertia."

30.2. **Comments have been received from Greenko Group, ReNew, O2 Power, WIPPA, Enel, National Solar Energy Federation of India, Hero Future Energy, Siemens Limited and POSOCO**

30.2.1. **Greenko Group, ReNew, O2 Power, WIPPA, Enel, National Solar Energy Federation of India,** and **Hero Future Energy** suggested inserting the following proviso in this clause:

"Provided that curtailed wind, solar and wind-solar hybrid energy shall be given deemed generation status.
Provided further that NLDC shall implement the transparent process for data posting related to curtailment of wind, solar and wind-solar hybrid energy to ensure that such curtailment with reason of grid security will be corroborated.
Provided further that RE generators shall be provided compensation for generation loss in a particular time-block based on wind speed/solar insolation level in that time-block."

30.2.2. **Siemens Limited** suggested the following addition to this clause:
"Special attention shall be given when renewable energy generators are connected radially to the grid through HVDC e.g. offshore wind park connected via HVDC to the main onshore grid, or large solar PV park connected directly to HVDC, etc. as the minimum inertia mentioned in the para above would not apply at the point of coupling of the renewable energy generators."

30.2.3. **POSOCO** commented that for maintaining inertia NLDC might need to bring quick start synchronous generation on bar, apart from other actions and suggested adding "bring quick start synchronous generation on bar" after the words "NLDC shall".

30.3. **Analysis and Decision**

30.3.1. The suggestion to provide deemed generation status for cases of curtailment due to grid security is rejected since grid security is not on commercial considerations but is a collective requirement of all entities connected to the grid.

30.3.2. The suggestions to post the data related to curtailment shall be taken up in the Detailed Operating Procedure of LDCs.

30.3.3. The identification of generating stations to be curtailed to ensure grid security shall be decided by RLDC/SLDCs based on the estimated relief such curtailment is likely to bring to the grid.

30.3.4. Suggestions of NLDC to add "quick start synchronous generation" have been accepted.

30.3.5. Regulation 30 (9) of the 2023 Grid Code Regulations has been modified as follows:

"(9) Inertia:
The power system shall be operated at all times with a minimum inertia to be stipulated by NLDC so that the minimum nadir frequency post reference contingency stays above the threshold set for under frequency load shedding (UFLS). <u>To maintain the minimum inertia, the NLDC may, if required, bring quick start synchronous generation on bar and</u> reschedule generation including curtailment of wind, solar and wind-solar hybrid generation, in coordination with the respective RLDCs and SLDCs. <u>The compensation for such quick start synchronous generation shall be included in the procedure to be prepared by NLDC and approved by the Commission</u>."

31. Frequency Control and Reserves (Regulation 30 (10)(c))

31.1. **Commission's Proposal**

31.1.1. The Commission had proposed the following in Regulation 30 (10)(c) of the Draft Regulations

"(c) The minimum quantum of PRAS required for reference contingency shall be declared by NLDC at the start of each financial year."

31.2. **Comments have been received from SRPC**

31.2.1. **SRPC** suggested including the provision to distribute and specify the minimum quantum of PRAS for each control area by NLDC/RLDCs.

31.3. **Analysis and Decision**

31.3.1. With regard to suggestions of SRPC, it is noted that PRAS is a mandatory requirement under the 2023 Grid Code. Hence the suggestions to include a minimum quantum for each control area is not accepted.

31.3.2. The provision as proposed in the Draft Regulations has been retained.

32. Frequency Control and Reserves (Regulation 30 (10)(d) and (e))

32.1. **Commission's Proposal**

32.1.1. The Commission had proposed the following in Regulation 30 (10)(d) of the Draft Regulations:

"(d) The generating stations and units thereof shall have the electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS.

(e) NLDC may also identify other resources such as ESS and demand resource to provide PRAS for which PRAS Providers shall be compensated in accordance with the Ancillary Services Regulations."

32.2. **Comments have been received from NTPC, Greenko Group, Tata Power, Enel, National Solar Energy Federation of India, ReNew, Hero Future Energy and Torrent Power Limited**

32.2.1. **NTPC** suggested that a proviso may be made for relaxation on the grounds of providing the PRAS to units which are older than 20 years and units of capacity lower than 250 MW are equipped with a Mechanical Hydraulic Governor.

NTPC further suggested that a provision may be made that whenever the Primary Reserve Ancillary Services are introduced, all PRAS providers, including generators, be compensated for providing the primary frequency response.

32.2.2. **Greenko Group, Tata Power, Enel, National Solar Energy Federation of India, ReNew,** and **Hero Future Energy** commented that CERC Ancillary Service regulation 2022 does not have a provision related to compensation of Primary Reserve Ancillary Service and sought clarification that under such a scenario how Primary Reserve Ancillary Service provider will be compensated.

32.2.3. **Torrent Power Limited** suggested that while determining the compensation, due care should be taken to ensure that the Discom is compensated for the cost incurred based on the technology deployed, as the cost is prohibitive when ESS based on battery technology is compared to Pumped Storage Hydro.

32.3. **Analysis and Decision**

32.3.1. It is noted that the requirement of governing systems has been provided in the 2023 Grid Code referring to CEA Technical Standards. Any specific exemption from compliance with CEA Technical Standards may be taken from CEA by the generating units. Further, the compensation for providing primary frequency response may be introduced under the Terms and Conditions of Tariff Regulations and Ancillary Services Regulations whenever deemed necessary.

32.3.2. Regulation 30 (10) (d) of the 2023 Grid Code Regulations have been modified as follows, and the provision as proposed in the Draft Regulation 30 (10) (e) has been retained

"(d) The generating stations and units thereof shall have electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS. The generating stations and units thereof with governors shall be under Free Governor Mode of Operation."

33. Frequency Control and Reserves (Regulation 30 (10)(g))

33.1. **Commission's Proposal**

33.1.1. The Commission had proposed the following in Regulation 30 (10)(g) of the Draft Regulations:

"(g) The generating units shall have their governors or controllers in operation at all times with droop settings of 3-6 % or as specified in the CEA Technical Standards for Connectivity as per the requirements mentioned in the Table 4."

TABLE 4: PRIMARY RESPONSE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	***Minimum unit size/Capacity***	***Up to***
Coal/Lignite Based	*200 MW and above*	*±5% of MCR*
Hydro	*25 MW and above non-canal based*	*±10% of MCR*
Gas based	*Gas Turbine above 50 MW*	*±5% of MCR*

Fuel/ Source	***Minimum unit size/Capacity***	***Up to***
		(corrected for ambience temperature)
Wind/ Solar/Renewable Hybrid Energy Project (commissioned after the date as specified in the CEA Technical Standards for Connectivity)*^	*Capacity of Generating station more than 10 MW and connected at 33 kV and above*	*10% of the maximum Alternating Current active power capacity in case of frequency deviations in excess of 0.3 Hz*

^Wind/Solar/Hybrid plant commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.

33.2. **Comments have been received from GE Renewable, SECI, IWPA, NHPC, NTPC, NPCIL, Sembcorp, and POSOCO**

33.2.1. **GE Renewable** has requested to clarify the following points:

a. BESS is asked at the turbine level or farm level for primary frequency response. Is it mandatory to be provided for each windfarm. It may be clarified if this is an optional ancillary service?

c. For frequency deviation in excess of 0.3hz whether it implies synthetic inertia, and time duration for which power is to be maintained at 10 %.

33.2.2. **SECI** suggested changing the reference of BESS as ESS and also to mandate the Standalone ESS to maintain Primary Reserves. SECI further requested to include Standalone ESS to the Primary Response table.

33.2.3. **IWPA** commented that since the wind speed/Solar insolation itself are varying in nature, wind and solar generators may be exempted from this requirement.

33.2.4. **NHPC** has suggested the following to be added to the table for the Hydro category under Minimum unit size, "(Except Run of the River Hydro Plants and plants having pondage up to 3 hours)".

33.2.5. **NTPC** has suggested that the minimum size and voltage level may be revised to 50MW and 220kV. It is also suggested not considering any BESS capacity for the plant which have been commissioned and under implementation based on tariff discovered through TBCB.

NTPC has also suggested that if primary frequency response is to be mandated for RE plants then it may be considered for RE plants (having a capacity of 50 MW and above) in line with conventional thermal generators and may be made mandatory prospectively.

NTPC suggested the following modification in the table:

Fuel/ Source	Minimum unit size/Capacity	Up to
Wind/	Capacity of Generating	<u>±5% of</u> the maximum

Solar/Renewable Hybrid Energy Project^*	station more than 50 MW and connected at 220 kV and above	Alternating Current active power capacity. in case of frequency deviations in excess of 0.3 Hz

^Wind/Solar/Hybrid plant shall have the option to provide optional primary response individually through BESS or through a common BESS installed at its pooling station/ISTS Substation.

* The RE stations shall be required to provide PRAS prospectively.

33.2.6. **NPCIL** has submitted that the Nuclear Power Plants (NPPs) of NPCIL are operated in "Turbine follows Reactor Mode". Hence, NPPs were exempted from Free Governor Mode of Operation (FGMO) as per the Regulation 5.2. of existing IEGC (Chapter-5- Operating Code; para-5.2 - System Security Aspects. It is requested that above provision may be incorporated in the revised / proposed IEGC accordingly.

33.2.7. **Sembcorp** suggested that the following proviso needs to be added for the Wind/ Solar/Renewable Hybrid Energy Project in the table.

'Provided that, Wind/Solar/ Renewable Hybrid Energy Project without BESS at its Pooling Station, shall provide primary response subject to availability of wind/solar resources'

33.2.8. **POSOCO** has suggested that the relaxation provided to the Wind/ Solar/Renewable Hybrid Energy Project may be reviewed. Wind/ Solar/Renewable Hybrid Energy plants should have the capability to activate primary response in both directions. These plants should have provisions to reduce the generation as per droop. However, the rise in generation may be limited to events involving a fall in frequency in excess of 0.3 Hz. The overload capability available in inverters should be used to provide a response in an upward direction. Accordingly, POSOCO suggested the following modification:

"(g)…..in the Table 4. NLDC/RLDC/SLDC shall intimate a revised requirement of the droop to selected stations, if required, to ensure grid stability and during black start exercises.

Fuel/Source	Minimum unit size/capacity	Up to
Wind/Solar/ Renewable Hybrid Energy Project* (commissioned after the date as specified in the CEA Technical Standards for Connectivity)^	Capacity of Generating station more than 10 MW and connected at 33kV and above	10% of the maximum Alternating Current active power capacity in case of frequency **rise and in case of fall in frequency in excess of 0.30 Hz** ~~in excess of 0.3 Hz~~

"^Wind/Solar/Hybrid plant commissioned after the date as specified in CEA Technical Standards for Connectivity shall **activate the control system to regulate the output of the generating unit as per primary frequency response requirement or** have the option to provide primary response individually through **Battery Energy Storage System** (BESS) or through a common BESS installed at its pooling station."

33.3. **Analysis and Decision**

33.3.1. With regard to the suggestions of GE, it is clarified that the primary response is mandated by CEA Standards and the same may be provided by installation of BESS. All compliances are required to be met at the interconnection point.

33.3.2. The suggestion of IWPA to exempt solar/wind generators from requirement to provide primary response is not accepted since the same is mandated by CEA Standards.

33.3.3. The suggestions of SECI to mandate primary response for ESS is not accepted as ESS is an emerging technology, and CEA Standards have yet to incorporate such requirements from ESS.

33.3.4. Suggestions of NHPC to exempt ROR from mandatory requirement of primary response has been accepted. The Commission has noted the suggestions of the stakeholders.

33.3.5. With respect to suggestions of NTPC to make primary response mandatory for RE generators prospectively, it is clarified that the requirements are already provided for in CEA Standards and shall be applicable from the date as provided in CEA Standards.

33.3.6. Considering suggestions of POSOCO, the primary response requirement for Wind and Solar generators has been provided as per CEA Standards.

33.3.7. The draft regulation has been modified, and a new clause has been added as 30 (10) (h) in the 2023 Grid Code Regulations as follows:

"(g) All the generating units shall have their governors or frequency controllers in operation all the time with droop settings of 3 to 6 % (for thermal generating units and WS Seller) or 0-10% (for hydro generating units) as specified in the CEA Technical Standards for Connectivity
(h) The primary response requirement shall be as mentioned in Table 4.

TABLE 3: PRIMARY RESPONSE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	***Minimum unit size/Capacity***	***Up to***
Coal/Lignite Based	*200 MW and above*	*±5% of MCR*
Hydro	*25 MW and above*	*±10% of MCR*
Gas based	*Gas Turbine above 50 MW*	*±5% of MCR (corrected for ambience temperature)*

Fuel/ Source	Minimum unit size/Capacity	Up to
WS Seller (commissioned after the date as specified in the CEA Technical Standards for Connectivity)	*Capacity of Generating station more than 10 MW and connected at 33 kV and above*	*As per CEA Technical Standards for Connectivity*

Provided that:
1. WS Sellers commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through ESS or through a common ESS installed at its pooling station.
2. Nuclear generating stations and hydro generating stations (with pondage up to 3 hours or Run of the river projects) shall be exempt from mandatory primary response. They may provide the primary response to the extent possible, considering the safety and security of machines and humans."

34. Frequency Control and Reserves (Regulation 30 (10)(h))

34.1. **Commission's Proposal**

34.1.1. The Commission had proposed the following in Regulation 30 (10)(h) of the Draft Regulations:

"(h) All generating stations mentioned in Table-4 (under clause (g) of this Regulation) shall have the capability of instantaneously picking up to a minimum 105% of their operating level and up to 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly and shall provide primary response. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC."

34.2. **Comments have been received from SRPC, Greenko Group, Enel, Tata Power, ReNew, O2 Power, WIPPA, Hero Future Energy, NTPC, POSOCO, Statkraft and Tehri HPP**

34.2.1. **SRPC** suggested including the provision for capability of reducing to 95% of their operating level up to their minimum turn down level constraint when the frequency rises suddenly.

34.2.2. **Greenko Group, Enel, Tata Power, ReNew, O2 Power, WIPPA, and Hero Future Energy** suggested excluding the Wind/ Solar/Renewable Hybrid Energy Project from compliance with this provision as these projects do not have the capability to operate at 105% or 110% of operating level when Solar insolation / Wind speed is not available at the site. Moreover, MCR should not be applicable to RE.

34.2.3. **NTPC** commented that the existing clause of grid code 2010 should be retained for better grid stability.

Further, NTPC commented that in case of RE generating station picking up capability beyond 105% of their MCR may be met from BESS/ other Storage and accordingly suggested the following at the end of the clause:

'Any generating station supplying beyond 105% of MCR as per grid requirement shall be considered as Ancillary service.'

34.2.4. **POSOCO** suggested that the Provisions related to Restricted Governor Mode of Operation (RGMO) as per IEGC 2010 and subsequent amendments, shall be discontinued and Primary response shall be provided for both increase and decrease in frequency from 50.000 Hz.

34.2.5. **Statkraft** has suggested inserting the following in the clause,

"Provided that for hydro, wind, solar, hybrid (based on renewable energy) generators this requirement is subject to availability of water, wind, solar insolation, as the case may be. Further, during high inflow season hydro plant operates on overload capacity and it will not have additional capability to increase the generation"

34.2.6. **Tehri HPP** has suggested that the provision of keeping the primary reserve margin is not applicable if DC is less than 100% of IC (less AEC). In such condition these reserves may be maintained by RLDC through scheduling.

34.3. **Analysis and Decision**

34.3.1 The suggestions of SRPC and POSOCO have been accepted and accordingly, a new sub-clause (j) has been inserted for the condition of frequency rise.

34.3.2. With respect to suggestions of Greenko and others about RE generating stations, it is clarified that the requirement of primary response is as notified by CEA under the CEA Technical Standards for Connectivity.

34.3.3. The suggestions of NTPC to consider response beyond 105% by RE generators as an ancillary service, it is clarified that RE generators are required to provide a minimum of 10% of response as per CEA Technical Standards. Anything beyond the mandated requirement may be considered in Ancillary Services Regulations in due course of time. Commission has noted the suggestions of the stakeholders.

34.3.4. With regard to suggestions of THDC, it is clarified that providing primary response is a mandatory requirement and is to be provided even when DC is less than 100%. Only scheduling has been restricted up to DC of the generating station so that the overload capacity up to 10% can be made available for primary response.

34.3.5. The draft regulation has been modified as 30 (10) (i) in the 2023 Grid Code Regulations as follows:

"(i) All generating stations mentioned in Table-4 (under sub-clause (g) of this clause) shall have the capability of instantaneously picking up to a minimum of 105% of their operating level and up to 105% or 110% of their MCR, as the case may be, when the frequency falls suddenly and thus providing primary response whenever conditions arise.
Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC."

35. Frequency Control and Reserves (Regulation 30 (10)(i))

35.1. **Commission's Proposal**

35.1.2. The Commission had proposed the following in Regulation 30 (10)(i) of the Draft Regulations:

"(i) The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control or

coordinated control system and no time delays shall be deliberately introduced. In case of renewable energy generating unit, reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency response within its capability. The inherent dead band of a generating unit/frequency controller shall not exceed +/- 0.03 Hz."

35.2. **Comments have been received from KSEBL, UPSLDC and SLDC Odisha**

35.2.2. **KSEBL** commented that in the case of primary response, it is not clearly mentioned about FGMO or RGMO. The inherent dead band for FGMO and RGMO of a generating unit/frequency controller should be kept not exceeding +/- 0.01 Hz and +/- 0.03 Hz respectively especially in the scenario of high RE penetration.

35.2.3. **UPSLDC** suggested that the dead band should be accompanied by time factor as well, say for example 0.03Hz per second or per 200 millisecond. In the absence of this time factor, Dead Band depends on sampling rate of frequency by the governor which varies from one plant to another.

35.2.4. **SLDC Odisha** commented that RGMO may be continued instead of FGMO, as the DSM rates are analogous to the RGMO. So, it may be continued.

35.3. **Analysis and Decision**

35.3.1. The suggestions of KSEBL and SLDC Odisha to clearly specify 'FGMO' have been accepted and included in Regulation 30(10)(d) of the 2023 Grid Code. A provision has also been included in Regulation 30(10)(k) for effective implementation of FGMO.

35.3.2. With regard to suggestions of UPSLDC to include the time factor, it is clarified that time factor may be specified in the Operating Procedure by NLDC/RLDC/SLDC after collecting necessary data from OEM and the generating stations.

35.3.3. The draft regulation has been modified as 30 (10) (k) in the 2023 Grid Code Regulations as follows:

"(k) The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control or coordinated control system and no time delays shall be deliberately introduced. In the case of a renewable energy generating unit, a reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency response within its capabilities. The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz.
<u>The governor shall be set with respect to a reference frequency of 50.000 Hz and response outside the dead band shall be with respect to a total change in frequency."</u>

36. Frequency Control and Reserves (Regulation 30 (10)(k))

36.1. **Commission's Proposal**

36.1.1. The Commission had proposed the following in Regulation 30 (10)(k) of the Draft Regulations:

"(k)The PRAS shall start immediately (within two seconds) when the frequency deviates beyond the dead band as specified in clause (i) of this Regulation and provide its full PRAS capacity obligation within 30 seconds and shall sustain up to five (5) minutes"

36.2. **Comments have been received from Adani Power, APP, NTPC and POSOCO**

36.2.1. **Adani Power** and **APP** commented that Full Response within 30 seconds is not achievable. The same obligation may be considered within 45 to 60 seconds.

36.2.2. **NTPC** commented that the time required to achieve full PRAS capacity obligation is around 30 - 60 secs as per the OEM of NTPC machines. NTPC also suggested adding the sentence, “After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute in case continued operation at the increased level is not sustainable” at the end of this clause.

36.2.3. **POSOCO** commented that PRAS needs to act after the governor senses that the frequency has breached the dead band. And suggested deleting the words **“(within two seconds)**”.

36.3. **Analysis and Decision**

36.3.1. Considering suggestions of APP, NTPC and Adani, the timeline has been modified from 30 seconds to 45 seconds. The Commission has noted the suggestions of the stakeholders.

36.3.2. With respect to suggestions of NTPC, it is clarified that under FGMO, the need for inclusion of provisions of ramp back is not warranted as the governor is functioning under FGMO mode.

36.3.3. The suggestions of POSOCO have been accepted.

36.3.4. The draft regulation has been modified as 30 (10) (m) in the 2023 Grid Code Regulations as follows,

“(m) The PRAS shall start immediately when the frequency deviates beyond the dead band as specified in sub-clause (k) of this clause and shall be capable of providing its full PRAS capacity obligation within 45 seconds and sustaining at least for the next five (5) minutes.”

37. Frequency Control and Reserves (Regulation 30 (10)(o))

37.1. **Commission’s Proposal**

37.1.1. The Commission had proposed the following in Regulation 30 (10)(o) of the Draft Regulations:

“(o) NLDC, RLDCs and SLDCs shall grade the median Frequency Response Performance annually, considering at least 10 reportable events. In case the median Frequency Response Performance is less than 0.75 as calculated as per Annexure-2, NLDC, RLDCs, SLDCs, as the case may be, after analyzing the FRP shall direct the concerned entities to take corrective action.”

37.2. **Comments have been received from SRPC, HPSLDC, WRPC and POSOCO**

37.2.1. **SRPC** suggested inserting “and persistent poor FRP would be reported to appropriate Commission.” at the end of this clause.

37.2.2. **HPSLDC** commented that the timeline for taking corrective action needs to be mentioned.

37.2.3. **WRPC** suggested that a provision be made so that all such cases may be reported to RPCs for its review.

37.2.4. **POSOCO** suggested that this shall be reported to the Commission on a quarterly basis.

37.3. **Analysis and Decision**

37.3.1. With regard to suggestions of SRPC and POSOCO to report the cases to the Commission, it is clarified that exception reports may be sent to the Commission with suggested actionable points. Non-performance should be discussed and resolved at the RPC level after analysing the reasons for non-performance.

37.3.2. The suggestions of WRPC have been accepted, and accordingly, the necessary provisions for review of RPC have been inserted in this Regulation.

37.3.3. The draft regulation has been modified as 30 (10) (q) in the 2023 Grid Code Regulations, and the same is as follows:

"(q) NLDC, RLDCs and SLDCs shall grade the median Frequency Response Performance annually, considering at least 10 reportable events. In case the median Frequency Response Performance is less than 0.75 as calculated as per Annexure- 2, NLDC, RLDCs, SLDCs, as the case may be, after analyzing the FRP shall direct the concerned entities to take corrective action. <u>All such cases shall be reported to the concerned RPC for its review</u>."

38. Frequency Control and Reserves (Regulation 30 (11)(a))

38.1. **Commission's Proposal**

38.1.1. The Commission had proposed the following in Regulation 30 (11)(a) of the Draft Regulations:

"(a)Secondary control is a centralized automatic function to regulate the generation or load in a control area to restore the frequency within the allowable band or replenish deployed primary reserves.

38.2. **Comments have been received from POSOCO**

38.2.1. **POSOCO** suggested deleting the words "or load" as Demand response may be specified as tertiary frequency control.

38.3. **Analysis and Decision**

38.3.1. With respect to suggestions of POSOCO, it is clarified that demand response may also come under secondary control and accordingly 'load' is retained.

38.3.2. The provision as proposed in the Draft Regulations has been retained.

39. Frequency Control and Reserves (Regulation 30 (11)(c))

39.1. **Commission's Proposal**

39.1.1. The Commission had proposed the following in Regulation 30 (11)(c) of the Draft Regulations:

"(c) Secondary control signals shall be automatically generated from NLDC and shall be transmitted to SRAS Providers through the concerned RLDC exercising the control area jurisdictions for desired automated response when the Area Control Error (ACE) goes beyond the minimum threshold limit of ±10 MW, which may be reviewed from time to time based on review of performance of SRAS.

Provided that as and when bi-directional communication system of SRAS providers with RLDCs is fully established, secondary control signals shall be automatically generated from the respective RLDC."

39.2. **Comments have been received from NHPC, SRPC and POSOCO**

39.2.1. **NHPC** commented that the minimum threshold limit is very narrow to initiate the signal for SRAS signal for any Regional grid as large as 70-80GW, it may lead to frequent SRAS corrections, ultimately causing wear and tear in machines affecting useful life. NHPC requested to increase this band.

39.2.2. **SRPC** suggested adding the word “of Regional ACE” after secondary control signals under the proviso.

39.2.3. **POSOCO** suggested the following modification:

“(c) Secondary control signals shall be automatically generated from NLDC**/RLDC** and shall be transmitted to SRAS Providers ~~**through the concerned RLDC exercising the control area jurisdictions**~~ for a desired automated response when the **regional** Area Control Error (ACE).

39.3. **Analysis and Decision**

39.3.1. With regard to suggestions of POSOCO and SRPC, it is clarified that the calculation of ACE is under sub-clause (d) where ACE is calculated for a region or a State and shall be construed accordingly. Further the words “for each region” have been inserted in the clause.

39.3.2. The suggestions of NHPC to increase minimum threshold limit are not accepted since the requirement is to maintain frequency close to reference frequency at all times and threshold has to be minimum to ensure this requirement.

39.3.3. The draft Regulation 30 (11)(c) has been modified as follows:

“(c) Secondary control signals shall be automatically generated from NLDC and shall be transmitted to SRAS Providers through the concerned RLDC exercising the control area jurisdictions for desired automated response when the Area Control Error (ACE) for each region goes beyond the minimum threshold limit of ±10 MW, which may be reviewed from time to time based on review of performance of SRAS.

Provided that as and when bi-directional communication system of SRAS providers with RLDCs is fully established, secondary control signals shall be automatically generated from the respective RLDC.”

40. Frequency Control and Reserves (Regulation 30 (11)(d))

40.1. **Commission’s Proposal**

40.1.1. The Commission had proposed the following in Regulation 30 (11)(d) of the Draft Regulations:

“(d)ACE of each State or Regional control, shall be auto calculated at the control centre of NLDC or RLDC or SLDC, as the case may be, based on telemetered values, and external inputs, namely, the Frequency Bias Coefficient and Offset referred to in clauses (e) and (f) respectively of this Regulation as per the following formula:

*ACE = (Ia– Is) – 10 * Bf * (Fa – Fs) + Offset*

Where,

……..”

40.2. **Comments have been received from POSOCO**

40.2.1. **POSOCO** suggested inserting the word “area” as below:

“(d) ACE of each State or Regional control **area**, shall be auto calculated……………”

40.3. **Analysis and Decision**

40.3.1. Suggestions of POSOCO have been accepted, and the word “area” has been inserted after “Regional control”.

"(d)ACE of each State or Regional control area, shall be auto calculated at the control centre of NLDC or RLDC or SLDC, as the case may be, based on telemetered values, and external inputs, namely, the Frequency Bias Coefficient and Offset referred to in clauses (e) and (f) respectively of this Regulation as per the following formula:

*ACE = (Ia– Is) – 10 * Bf * (Fa – Fs) + Offset*

Where,

……."

41. Frequency Control and Reserves (Regulation 30 (11)(g))

41.1. **Commission's Proposal**

41.1.1. The Commission had proposed the following in Regulation 30 (11)(g) of the Draft Regulations:

"(g)Secondary control may be operated under tie-line bias control, flat frequency control or flat tie-line control mode depending on grid requirements:

Provided that NLDC in coordination with RLDC and SLDC shall lay down in its Detailed operating procedure after stakeholder consultation, the conditions during which a particular mode shall be chosen and shall document the reasons for operating in a particular mode:

Provided further that the coordinated operation of AGC by the nested control areas shall be adopted based on mutually agreed protocols."

41.2. **Comments have been received from POSOCO**

41.2.1. **POSOCO** suggested the following modification:

"(g)Secondary control may be operated under tie-line bias control, flat frequency control, ~~**or**~~ flat tie-line control **or suspended** mode depending on grid requirements:

…."

41.3. **Analysis and Decision**

41.3.1. Considering suggestions of POSOCO, the condition of suspension of secondary control has been included in the Regulations.

41.3.2. Regulation 30 (11) (g) of the 2023 Grid Code Regulations has been modified as follows:

"(g) Secondary control may be operated under tie-line bias control, flat frequency control or flat tie-line control mode depending on grid requirements:

Provided that <u>Secondary control may be suspended due to system maintenance or grid security or for any other reasons to be recorded in writing</u>:

Provided further that NLDC in coordination with RLDC and SLDC shall lay down in the Detailed operating procedure after stakeholder consultation, the conditions during which a particular mode shall be chosen and shall document the reasons for operating in a particular mode:

Provided also that the coordinated operation of AGC by the nested control areas shall be adopted based on mutually agreed protocols."

42. Frequency Control and Reserves (Regulation 30 (11)(i))

42.1. **Commission's Proposal**

42.1.1. The Commission had proposed the following in Regulation 30 (11)(i) of the Draft Regulations:

"(i) RLDCs and SLDCs shall compute the ACE of the respective regional or state control area in real time based on telemetered data. ACE data shall be archived at the interval of 10 seconds or lower. RLDCs shall share the data with NLDC."

42.2. **Comments have been received from SRPC**

42.2.1. **SRPC** suggested that SLDC shall also be mandated to share the data with RLDCs/NLDC.

42.3. **Analysis and Decision**

42.3.1. The suggestions of SRPC have been accepted. Regulation 30 (11) (i) of the 2023 Grid Code Regulations has been modified as follows:

"(i) RLDCs and SLDCs shall compute the ACE of the respective regional or state control area in real time based on telemetered data. ACE data shall be archived at an interval of 10 seconds or less. RLDCs shall share the data with NLDC. <u>SLDC shall share the data with the concerned RLDC and NLDC</u>."

43. Frequency Control and Reserves (Regulation 30 (11)(j))

43.1. **Commission's Proposal**

43.1.1. The Commission had proposed the following in Regulation 30 (11)(j) of the Draft Regulations:

"(j) The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes. The secondary reserves shall be gradually replaced by tertiary reserves within 30 minutes"

43.2. **Comments have been received from NTPC and POSOCO**

43.2.1. **NTPC** commented that in coal-based units, the command for change of generation goes instantly to the CMC system, which in turn, increases or decreases the coal feeding through boiler master control. Actual load change is dependent on boiler response which is typically 2-3 minutes. Accordingly, NTPC suggested modifying the clause as below:

"The SRAS Providers shall start responding to SRAS signals **instantaneously with load changes in 2-3 minutes** and shall be capable of providing the entire SRAS capacity obligation **at the rate of declared ramping rate and** sustaining at least for the next thirty (30) minutes."

43.2.2. **POSOCO** suggested the following modification:

"(j)…to SRAS signals within thirty (30) seconds **of receipt of signal** and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes **of receipt of signal** and sustaining ..."

43.3. **Analysis and Decision**

43.3.1. With regard to suggestions of NTPC, it is clarified that the entire framework of reserves under primary, secondary and tertiary would work effectively when their response timing is properly synchronised. Further, there are multiple generating stations which would be responding to the Secondary signal and not all generating stations would have delayed responses. Considering this requirement, the time to start responding to the SRAS signal is retained as thirty seconds.

43.3.2. Accepting POSOCO suggestion Regulation 30 (11) (j) of the 2023 Grid Code Regulations have been modified as follows:

"(j) The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds <u>of receipt of the signal</u> and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining it at least for the next thirty (30) minutes. The secondary reserves shall be gradually replaced by tertiary reserves within 30 minutes."

44. Frequency Control and Reserves (Regulation 30 (11)(k))

44.1. Commission's Proposal

44.1.1. The Commission had proposed the following in Regulation 30 (11)(k) of the Draft Regulations:

"(k) With due regard to the requirement of planning reserve margin and resource adequacy referred to in clause (3) of Regulation 5 of these regulations, and based on the following methodologies, the secondary reserve capacity shall be estimated by RLDCs for their respective regional control areas:

The positive and negative secondary reserve capacity for any control area for a financial year shall be equal to 99 percentile of positive and negative ACE respectively of that control area during the previous financial year (Detailed Procedure shall be as per Annexure-3 to these regulations),

OR

The secondary reserves capacity for any control area shall be equal to the 110 % of largest unit size in the respective regional control area or state control area plus load forecast error plus wind forecast error plus solar forecast error during the previous financial year.

44.2. Comments have been received from POSOCO

44.2.1. **POSOCO** commented that the details about the adopted methodology for assessment of reserves may be covered under Detailed procedure by RLDC and suggested the following modification in the first clause and further suggested deleting both provisos of this Regulation:

"(k) ~~With due regard to the requirement of planning reserve margin and resource adequacy referred to in clause (3) of Regulation 5 of these regulations, and based on the following methodologies,~~ The secondary reserve capacity **requirement** shall be estimated by RLDCs for their respective regional control areas **based on a Detailed Procedure as per Annexure-3, which may be reviewed from time to time based on experience**."

44.3. Analysis and Decision

44.3.1. Considering the suggestions of POSOCO an additional option have been inserted as "*Such other methodology as may be stipulated by NLDC after obtaining the due approval of the Commission*". However, the principles for calculation of reserve requirement have been retained in the Regulations as the same is also to be referred for calculation of State level reserves under sub-clause (l) of this

Regulation.

44.3.2. Regulation 30 (11) (k) of the 2023 Grid Code Regulations has been modified as follows:

"(k) With due regard to the requirement of planning reserve margin and resource adequacy referred to in Chapter 2 of these regulations and based on the following methodologies, the secondary reserve capacity requirements shall be estimated by RLDCs for their respective regional control areas:
The positive and negative secondary reserve capacity requirements for any control area for a calendar year shall be equal to the 99 percentile of positive and negative ACE respectively of that control area during the previous financial year (Detailed Procedure shall be as per Annexure-3 to these regulations, which may be reviewed as and when considered necessary),
OR
The secondary reserve capacity requirement for any control area shall be equal to the 110 % of the largest unit size in the respective regional control area or state control area plus load forecast error plus wind forecast error plus solar forecast error during the previous calendar year.
OR
<u>Such other methodology as may be stipulated by NLDC after obtaining the due approval of the Commission</u>."

45. Frequency Control and Reserves (Regulation 30 (11)(l))

45.1. **Commission's Proposal**

45.1.1. The Commission had proposed the following in Regulation 30 (11)(l) of the Draft Regulations:

"(l) Unless otherwise specified by the concerned SERC, the methodology specified in clause (k) of this Regulation shall be adopted by the SLDCs to estimate the secondary reserve capacity in their respective control areas."

45.2. **Comments have been received from Torrent Power Limited and POSOCO**

45.2.1. **Torrent Power Limited** commented that in a catena of judgments, it has been held that the State Commission shall only be guided by the Regulations of the Hon'ble Commission. Hence, there can be no mandate on the State Commissions or SLDC to adopt CERC Regulations as same is contrary to the law.

45.2.2. **POSOCO** suggested adding the word "requirement" after the word "capacity".

45.3. **Analysis and Decision**

45.3.1. With respect to comments of Torrent Power Limited, it is clarified that under the Act, the State Grid Code is to be consistent with the Grid Code specified under clause (h) of sub-section (1) of section 79. Such consistency is required to ensure the integrated operation of the Grid. Accordingly, the clause is retained.

45.3.2. Suggestions of POSOCO have been accepted, and the word "requirement" has been included in Regulation 30(11)(l) as given below:

"(l) Unless otherwise specified by the concerned SERC, the methodology specified in clause (k) of this Regulation shall be adopted by the SLDCs to estimate the secondary reserve capacity requirement in their respective control areas."

46. Frequency Control and Reserves (Regulation 30 (11)(m))

46.1. **Commission's Proposal**

46.1.1. The Commission had proposed the following in Regulation 30 (11)(m) of the Draft Regulations:

"(m)The reserve capacity as per the methodology mentioned in clause (k) of this Regulation shall be estimated by 15th February every year for next financial year and submitted to NLDC."

46.2. **Comments have been received from POSOCO**

46.2.1. **POSOCO** suggested adding the word "requirement" after the word "capacity" and replacing the word "February" with "January".

46.3. **Analysis and Decision**

46.3.1. The suggestions of POSOCO have been accepted .

46.3.2. Regulation 30 (11) (m) of the 2023 Grid Code Regulations has been modified as follows:

"(m) The reserve capacity <u>requirement</u> as per the methodology mentioned in sub-clauses (k) and (l) of this clause shall be estimated by each RLDC and SLDC respectively by 15th <u>January</u> every year for the next financial year and submitted to NLDC."

47. Frequency Control and Reserves (Regulation 30 (11)(o))

47.1. **Commission's Proposal**

47.1.1. The Commission had proposed the following in Regulation 30 (11)(o) of the Draft Regulations:

"(o) NLDC shall allocate such All India secondary reserves capacity, to be maintained at regional control area and at State control area, based on the estimated reserves as per clause (k) of this Regulation and publish the information on its website by 1st March every year."

47.2. **Comments have been received from POSOCO**

47.2.1. **POSOCO** suggested replacing the word "allocate" with "publish and replacing the word "1st March" with "25th January".

47.3. **Analysis and Decision**

47.3.1. Suggestions of POSOCO regarding the date have been accepted. Regulation 30 (11) (o) of the 2023 Grid Code Regulations has been modified as follows:

"(o) NLDC shall allocate such All India secondary reserves capacity, to be maintained at regional control area and at State control area, based on the estimated reserves as per sub-clauses (k) and (l) of this clause and publish the information on its website by 25th January every year."

48. Frequency Control and Reserves (Regulation 30 (11)(p))

48.1. **Commission's Proposal**

48.1.1. The Commission had proposed the following in Regulation 30 (11)(p) of the Draft Regulations

"(p) Each State control area shall ensure availability of the quantum of secondary reserve at the State control area on day ahead basis with due regard to the secondary reserves

estimated and allocated for that State by NLDC in terms of clause (o) of this Regulation, and inform the same to the concerned RLDC and NLDC."

48.2. **Comments have been received from POSOCO**

48.2.1. **POSOCO** suggested the following modification:

"Each State control area shall ensure availability of the quantum of secondary reserve at the State control area on day ahead basis with due regard to the secondary reserves estimated and **to be maintained within** ~~allocated for~~ that State **as published** by NLDC in terms of clause (o) of this Regulation, and inform the same to the concerned RLDC and NLDC.

The modalities for information exchange and timelines in respect of reserves shall be covered under as per NLDC detailed procedure."

48.3. **Analysis and Decision**

48.3.1. Considering suggestions of POSOCO, the draft regulation has been modified as 30 (11) (q) in the 2023 Grid Code Regulations as follows:

"(q) Each State control area shall ensure the availability of the quantum of secondary reserve at the State control area with due regard to the secondary reserves estimated and allocated for that State <u>as published by</u> NLDC in terms of sub-clauses (o) <u>and (p) of this clause,</u> and inform the same to the concerned RLDC and NLDC <u>two days before the day of scheduling.</u> <u>The modalities for information exchange and timelines in this respect shall be as per the detailed procedure to be issued by NLDC</u>."

49. Frequency Control and Reserves (Regulation 30 (11)(q))

49.1. **Commission's Proposal**

49.1.1. The Commission had proposed the following in Regulation 30 (11)(q) of the Draft Regulations:

"(q) NLDC through RLDCs shall re-assess the quantum of requirement of secondary reserve at the state control area and regional level on day ahead basis and also on real time basis, with due regard inter alia to the secondary reserve maintained at State control area and the need to replenish primary reserves, as specified in the Ancillary Services Regulations.

49.2. **Comments have been received from POSOCO**

49.2.1. **POSOCO** commented that the real time position of states is unknown and Continuous re-assessment and broadcasting information is a challenge and suggested replacing the word "re-assess" with "monitor" and further suggested inserting a new clause after this clause (q) under this Regulation.

"(r) NLDC, RLDC, SLDC would indicate the shortfall in secondary reserves and announce emergency alerts for such periods."

49.3. **Analysis and Decision**

49.3.1. The suggestion of POSOCO to replace 're-assess' with 'monitor' is not accepted, as it is the POSOCO that needs to calculate the amount of reserves at the regional level for ensuring grid security. Considering suggestions of POSOCO, a new sub-clause (u) has been inserted as follows:

"(u)NLDC, RLDC, SLDC shall indicate the shortfall in secondary reserves, if any, and announce emergency alerts for such periods."

49.3.2. The draft regulation has been modified as 30 (11) (r) in the 2023 Grid Code Regulations as follows:

"(r) NLDC through RLDCs shall re-assess the quantum of the requirement for secondary reserves at the regional level with due regard inter alia to the secondary reserves maintained at State control area and the need to replenish primary reserves two days before the day of scheduling inter alia to identify reserves to be brought on bar under SCUC (in terms of Regulation 46 of these regulations)."

50. Frequency Control and Reserves (Regulation 30 (11)(r) & (s))

50.1. **Commission's Proposal**

50.1.1. The Commission had proposed the following in Regulation 30 (11)(r) & (s) of the Draft Regulations:

"(r) If a State falls short of maintaining secondary reserve capacity as allocated to it in terms of clause (o) of this Regulation, the NLDC through RLDC shall procure such Secondary reserve capacity on behalf of the State and allocate the cost of procurement of such capacity on that State based on the methodology specified in the Ancillary Service Regulations.

(s) Secondary reserves shall be procured by the NLDC from a generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis, connected to inter-State transmission system or intra-State transmission system in accordance with the Ancillary Services regulations."

50.2. **Comments have been received from KSEBL, Torrent Power Limited, POSOCO and AP Transco**

50.2.1. **KSEBL** suggested that NLDC through RLDC shall issue a warning message to SLDC before procuring any reserve capacity on behalf of the state so that some opportunity is left with SLDC for acting.

50.2.2. **Torrent Power Limited** commented that with RTM and Contingency markets being in place, there is no requirement for NLDC/RLDC to procure any such secondary reserve; however, if procured by NLDC/RLDC, it needs to be ensured that the same is cost-effective w.r.t market mechanism. Accordingly, Torrent Power Limited requested the Commission to exercise appropriate oversight on the decision of NLDC/RLDC, including specifying guidelines for such procurement.

50.2.3. **POSOCO** commented that Procuring reserves for a state and allocating the cost to that state may be a challenge. A detailed commercial mechanism is required to manage such a process.

50.2.4. **AP Transco** commented that to introduce secondary control in Indian power system, AGC implementation is mandatory for ancillary units in respective control area, hence implementation may be deferred.

As per EA Act Sections 26.2 and 27.2, it is explicitly mentioned that NLDC and RLDC shall not be involved in the business of trading electricity but these clauses, it is proposed to procure power by NLDC and RLDC. Hence it may be reviewed.

As mentioned in the preamble, EA Act 2003 section 32 made SLDC responsible for the secure and economic operation of the State grid. Ownership on Reserves (URS can be used as an Ancillary of the beneficiary) in the CGS contracts is transferred to NLDC a day and sixteen hours in advance, but the responsibility of secure operation is on SLDC. Hence the reserves concept is indirectly affecting the secure and economic operation of state control area by reducing flexibility in operation.

50.3. **Analysis and Decision**

50.3.1. With regard to comments of KSEBL, it is clarified that States are required to update the status of reserves on a three day ahead basis (two days before the day of scheduling) and a day ahead basis, based on which NLDC shall procure reserves. It has also been provided under sub-clause (t) of this regulation that NLDC shall also provide an advance intimation to the concerned State. The Commission has noted the suggestions of the stakeholders.

50.3.2. With regard to suggestions of Torrent Power Limited, it is clarified that markets for sale/purchase of electricity by selling and buying entities cannot take away the requirement of reserves that need to be maintained for secure operation of the grid. All the actions of NLDC/RLDC and other entities are under oversight of the Commission.

50.3.3. With regard to the suggestions of POSOCO, it is observed that regulations provide for a detailed procedure to be formulated by NLDC in regard to the allocation of the cost of procurement of such capacity to that State.

50.3.4. With regard to suggestions of AP Transco, it is clarified that AGC has already been mandated for the generating units under the control area of RLDC. Further, States should also bring the units on AGC to ensure secondary response from units within the State control area. NLDC and RLDC are responsible for the secure operation of the grid. The reserves are being procured not for earning any trading margin or commercial gains but only for grid security purposes as per the Regulations issued by the Commission. SLDC may keep reserves in the identified units by SLDC. The framework developed by States to procure such reserves may be developed at the State level.

50.3.5. The draft regulation has been modified as 30 (11) (t) & (v), respectively, in the 2023 Grid Code Regulations as follows:

"(t) If a State falls short of maintaining secondary reserve capacity as allocated to it in terms of sub-clauses (o) or (p) of this clause, whichever is lower, the NLDC through RLDC shall procure such Secondary reserve capacity on behalf of the State under advance intimation to the concerned State and allocate the cost of procurement of such capacity to that State based on the methodology as per the detailed procedure to be issued by the NLDC after approval of the Commission.
(v) Secondary reserves shall be procured by the NLDC from a generating station or an entity having energy storage resources or an entity capable of providing demand response, on a standalone or aggregated basis, connected to an inter-State transmission system or an intra-State transmission system in accordance with the Ancillary Services regulations."

51. Frequency Control and Reserves (Regulation 30 (11)(t))

51.1. **Commission's Proposal**

51.1.1. The Commission had proposed the following in Regulation 30 (11)(t) of the Draft Regulations:

"(t) All thermal and hydro generating stations shall make arrangements to enable automatic operation of plant from the appropriate load despatch centre by integrating the controls and tele-metering features of their system into the automatic generation control in accordance with the CEA Technical Standards for Construction and the CEA Technical Standards for Connectivity. The communication system shall be established in accordance with the CEA Communication Regulations".

51.2. **Comments have been received from SRPC, KSEBL, NHPC and NTPC**

51.2.1. **SRPC** suggested replacing the word "thermal and hydro generating stations" with "SRAS service providers".

51.2.2. **KSEBL** and **NHPC** suggested that the cost of investment AGC shall be made applicable for hydro stations with a capacity greater than 25 MW (excluding Run-of-River Plants, irrespective of size). NHPC also referred Commission Order dated 28th August 2019 in the matter of Implementation of Automatic Generation Control (AGC), where the Commission directed that All new thermal ISGS stations with an installed capacity of 200 MW and above and hydro stations having a capacity exceeding 25 MW excluding the Run-of-River Hydro Projects irrespective of size of the generating station and whose tariff is determined or adopted by CERC shall mandatorily have the capability to provide AGC support.

51.2.3. **NTPC** commented that some of the units that are older than 20 years and units of capacity lower than 250 MW are equipped with a Mechanical Hydraulic Governor without the provisions of CMC and hence, cannot respond to remote AGC signals. Accordingly, such units may be relaxed on technical grounds for automatic operation of plant from the appropriate load despatch Centre based on capacity or age on a case-to-case basis.

51.3. **Analysis and Decision**

51.3.1. The suggestions of SRPC are not accepted, since the mandate is as per CEA Technical Standards. However, suggestions of NTPC and NHPC to include minimum unit size have been accepted. The Commission has noted the suggestions of the stakeholders.

51.3.2. The draft regulation has been modified as 30 (11) (w) in the 2023 Grid Code Regulations as follows:

"(w) All thermal generating stations <u>having a capacity of more than 200 MW</u> and hydro generating stations <u>having a capacity of more than 25 MW</u> shall make arrangements to enable automatic operation of the plant from the appropriate load despatch centre by integrating the controls and telemetering features of their system into the automatic generation control in accordance with the CEA Technical Standards for Construction and the CEA Technical Standards for Connectivity. The communication system shall be established in accordance with the CEA Communication Regulations."

52. Frequency Control and Reserves (Regulation 30 (11)(u))

52.1. **Commission's Proposal**

52.1.1. The Commission had proposed the following in Regulation 30 (11)(u) of the Draft Regulations:

"(u) All renewable energy generating stations and ESS shall be enabled with frequency controller to provide secondary control in accordance with the CEA Connectivity Standards and the communication system shall be established in accordance with the CEA Technical Standards for Communication."

52.2. **Comments have been received from SRPC, Greenko Group, Tata Power, Enel, ReNew, National Solar Energy Federation of India, O2 Power, WIPPA, Hero Future Energy, NTPC and POSOCO**

52.2.1. **SRPC** suggested that for renewable energy generating stations and ESS secondary control is not mandated in CEA Connectivity Standards; therefore, this provision may be mandated only for the participating renewable energy generating stations and ESS.

52.2.2. **Greenko Group, Tata Power, Enel, ReNew, National Solar Energy Federation of India, O2 Power, WIPPA, and Hero Future Energy** sought clarification on whether this clause is a mandatory requirement which RE generator /ESS are bound to comply as under CERC Ancillary Service Regulation 2022, SRAS/TRAS is to be provided on a voluntary basis.

52.2.3. **NTPC** suggested that Secondary Control may not be mandated for RE plants as RE generation is not to be curtailed except for grid security concerns.

52.2.4. **POSOCO** suggested replacing the word "frequency controller" with "the facility to control active power injection" as the same terminology used in CEA Standards, 2019.

52.3. **Analysis and Decision**

52.3.1. With regard to suggestions of SRPC, it is clarified that requirements of active power control are to be met as per CEA Standards. The clause requires the provision of a facility to control active power injection and adequate communication to be put in place, as per CEA Standards.

52.3.2. The draft regulation has been modified as 30 (11) (x) in the 2023 Grid Code Regulations as follows,

"(x) All renewable energy generating stations and ESS shall be equipped with the <u>facility to control active power injection</u> in accordance with the CEA Connectivity Standards and the communication system shall be established in accordance with the CEA Technical Standards for Communication."

53. Frequency Control and Reserves (Regulation 30 (12)(g)(i))

53.1. **Commission's Proposal**

53.1.1. The Commission had proposed the following in Regulation 30 (12)(g)(i) of the Draft Regulations:

"(i) To replenish the secondary reserve, in case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW;"

53.2. **Comments have been received from SRPC**

53.2.1. **SRPC** suggested removing the words "for more than 100 MW" as some states/UT total secondary requirement may be less than 100 MW, as some states/UT total secondary requirement may be less than 100 MW

53.3. **Analysis and Decision**

53.3.1. Considering suggestions of SRPC, 20 MW have been inserted for NER. The draft regulation 30 (12) (j) (i) has been modified as follows,

"i. To replenish the secondary reserve, in case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW (20 MW in the case of NER) or in respect of a State such other volume limit as may be specified by the respective SERC;"

54. Frequency Control and Reserves (Regulation 30 (12)(h))

54.1. **Commission's Proposal**

54.1.1. The Commission had proposed the following in Regulation 30 (12)(h) of the Draft Regulations:

"(h) The quantum of reserves procured by each State control area shall be informed to the concerned RLDC."

54.2. **Comments have been received from POSOCO**

54.2.1. **POSOCO** suggested adding the following sentence at the start of this clause:

"The modalities for information exchange and timelines in respect of tertiary reserves shall be as per NLDC detailed procedure."

54.3. **Analysis and Decision**

54.3.1. The suggestions of POSOCO have been accepted, and the suggested clause has been inserted as sub-clause (l).

54.3.2. The draft regulation has been modified as 30 (12) (k), respectively, in the 2023 Grid Code Regulations as follows,

"(k) The quantum of reserves procured by each State control area shall be <u>communicated</u> to the concerned RLDC."

55. Frequency Control and Reserves (Regulation 30 (13))

55.1. **Commission's Proposal**

55.1.1. The Commission had proposed the following in Regulation 30 (13) of the Draft Regulations:

"(13) The control area wise performance of SRAS and TRAS shall be evaluated in accordance with the Detailed Procedure prepared by NLDC."

55.2. **Comments have been received from WBSEDCL, Nabha Power Limited, WRPC and POSOCO**

55.2.1. **WBSEDCL** commented that to maintain secondary & tertiary reserve both at the State & ISGS level, which may reduce the share of concerned state beneficiary Discoms from those generating stations. In turn, the affected beneficiaries have to procure the same quantum of power from the spot market to meet their shortfall; the price on such occasions may be higher than that of the SRAS & TRAS provider generating stations. Hence, the cost of ancillary power in such cases should be the landed market price or the SRAS/TRAS service provider's generation cost, whichever is higher.

55.2.2. **Nabha Power Limited** commented that VWO should be allowed for specific periodic tests for turbines, and duration and periodicity may be guided in Grid Code. RGMO performance (PRAS) may not be achieved during VWO testing as a governing reserve is not available; hence, such cases should be excluded under mandatory RGMO compliance.

Further, Power plants like NPL, which are based on super-critical technology and were designed for washed Indian coal (higher GCV range), in case of poor coal quality condition, RGMO demand (PRAS) is not met up to a satisfactory level. Such cases should be excluded under mandatory RGMO compliance.

55.2.3. **WRPC** suggested inserting the provision “A SRAS and TRAS report containing all the incidents and reasons where SRAS and TRAS were used, to be submitted by NLDC/RLDC to the concerned RPC every month for its review”.

55.2.4. **POSOCO** suggested the following modification”

“(13) The control area wise performance of SRAS, ~~**and**~~ TRAS **and SRAS/TRAS providers** shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.”

55.3. **Analysis and Decision**

55.3.1. With regard to suggestions of WBSEDCL, it is clarified that for secure operation of the grid, the reserves are required to be maintained at the regional level as well as at the State level. A careful balance needs to be achieved to meet the shortfall in power requirements and maintaining the reserves so that grid is operated in secure manner at all times without any failure.

55.3.2. With regard to suggestions of Nabha Power, it is clarified that the 2023 Grid Code requires all entities to operate under FGMO, and RGMO provisions as per the 2010 Grid Code have been done away with. Further, for any specific technical difficulty, the entity may make an appropriate application, elaborating such difficulty, for seeking such relief.

55.3.3. The suggestions of WRPC to share a report with RPC may be considered by NLDC in its detailed procedure as required.

55.3.4. Regulation 30 (13) of the 2023 Grid Code Regulations has been modified as follows:

“(13) The control area wise performance of SRAS, TRAS providers shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.”

56. Operational Planning (Regulation 31 (2)(a))

56.1. **Commission’s Proposal**

56.1.1. The Commission had proposed the following in Regulation 31 (2)(a) of the Draft Regulations:

“(a) Each SLDC shall carry out demand estimation as part of operational planning after duly factoring in the demand estimation done by STU as part of resource adequacy planning referred to in clause (2) of Regulation (5) of these regulations. Demand estimation by SLDC shall be for both active power and reactive power incident on the transmission system based on the details collected from distribution licensees, grid-connected distributed generation resources, captive power plants and other bulk consumers embedded within the State.

(b) Each SLDC shall develop methodology for daily, weekly, monthly, yearly demand estimation in MW and MWh for operational analysis as well as resource adequacy purposes. Each SLDC, while estimating demand may utilize state of the art tools, weather data, historical data and any other data. For this purpose, all distribution licensees shall maintain historical database of demand."

56.2. **Comments have been received from Torrent Power Limited, GRIDCO and POSOCO**

56.2.1. **Torrent Power Limited** commented that the exercise is carried out in line with the requisite guidelines prescribed by the State Commission for demand forecasting and planning for power procurement. Therefore, it suggested a review of the requirements of such a provision.

56.2.2. **GRIDCO** commented that Guidelines may be prescribed by the Forum of Regulators (FOR) in respect of this clause.

56.2.3. **POSOCO** commented that there are different interpretations of demand in different regions and states. Therefore, uniformity in the treatment of demand across all regions is required and shall be defined clearly.

56.3. **Analysis and Decision**

56.3.1. The suggestions of Torrent Power, GRIDCO, and POSOCO have been incorporated in Chapter-2 of the 2023 Grid Code, where guidelines for demand estimation are to be developed by the Forum of Regulators.

57. Operational Planning (Regulation 31 (2)(d))

57.1. **Commission's Proposal**

57.1.1. The Commission had proposed the following in Regulation 31 (2)(d) of the Draft Regulations:

"(d) Each SLDC shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVAr on monthly and quarterly basis for the nodes 132 kV and above for preparation of scenarios for computation of TTC and ATC by the concerned RLDC and NLDC."

57.2. **Comments have been received from POSOCO, PCKL, KPTCL and Torrent Power**

57.2.1. **POSOCO, PCKL,** and **KPTCL** have suggested substituting the words "132 kV" with "110 kV" or writing as 132 kV (or 110 kV as applicable) as Karnataka State has stations at a voltage level of 110KV.

57.2.2. **Torrent Power** commented that the data of interface points would suffice the requirement of the SLDC/NLDC, and Such interface points may be at 220kV or above. Accordingly, instead of specifying the voltage level of 132 kV, reference should be given to interface points.

57.3. **Analysis and Decision**

57.3.1. The suggestions to substitute 132 kV by 110 kV have been accepted.

57.3.2. With regard to suggestions of Torrent Power, it is clarified that the data is required for operational planning, which is to be done for the entire grid and the intra-State system is an integral part of the Grid; hence data at all such nodes as specified is required to be furnished.

58. Operational Planning (Regulation 31 (2)(e))

58.1. **Commission's Proposal**

58.1.1. The Commission had proposed the following in Regulation 31 (2)(e) of the Draft Regulations:

"(e) SLDC shall also estimate peak and off-peak demand (active as well as reactive power) on weekly and monthly basis for load - generation balance planning as well as for operational planning analysis, which shall be a part of the operational planning data. The demand estimates mentioned above shall have granularity of a time block. The estimate shall cover the load incident on the grid as well as net load incident taking into account embedded generation in the form of roof-top solar and other distributed generation."

58.2. **Comments have been received from POSOCO**

58.2.1. **POSOCO** suggested adding the following sentence at the end under Regulation 31(2)(e):

"In case of bulk consumer, open access consumers or deemed distribution licensees connected to ISTS shall estimate and furnish their demand to respective RLDC."

58.3. **Analysis and Decision**

58.3.1. The suggestions of POSOCO have been accepted, and a new sub-clause (f) has been inserted as follows:

"(f) *The entities such as bulk consumers or distribution licensees that are directly connected to ISTS shall estimate and furnish such a demand estimate to the concerned RLDC."*

59. Operational Planning (Regulation 31 (2)(f))

59.1. **Commission's Proposal**

59.1.1. The Commission had proposed the following in Regulation 31 (2)(f) of the Draft Regulations:

"(f) Based on the demand estimate furnished by the SLDCs, each RLDC shall prepare the regional demand estimate and submit to NLDC. NLDC, based on regional demand estimate furnished by RLDCs, shall prepare national demand estimate."

59.2. **Comments have been received from POSOCO**

59.2.1. **POSOCO** suggested adding the words "and other entities directly connected to ISTS" before the word "each RLDC".

59.3. **Analysis and Decision**

59.3.1. The suggestions of POSOCO have been accepted. The draft regulation has been modified as 31 (2) (g) in the 2023 Grid Code Regulations as follows:

"(g) Based on the demand estimate furnished by the SLDCs and other entities directly connected to ISTS, each RLDC shall prepare the regional demand estimate and submit it to the NLDC. NLDC, based on regional demand estimates furnished by RLDCs, shall prepare national demand estimate."

60. Operational Planning (Regulation 31 (2)(g))

60.1. **Commission's Proposal**

60.1.1. The Commission had proposed the following in Regulation 31 (2)(g) of the Draft Regulations:

"(g) Timeline for submission of demand estimate data by SLDCs to respective RLDC and RPC shall be as follows:

Table 5: Timeline for Demand Estimation

Daily demand estimation	*10:00 hours of previous day*
Weekly demand estimation	*First working day of previous week*
Monthly demand estimation	*Fifth day of previous month*
Yearly demand estimation	*31st August of the previous year*

60.2. **Comments have been received from SRPC and POSOCO**

60.2.1. **SRPC**, in line with the Outage Planning/ LGBR and to get more accurate data, suggested modifying the table as below:

Demand Estimation	Timeline	Furnished to
Daily	By 10:00 hrs of D-1 & D-2	RLDC
Weekly	First working day of previous week	RLDC
Monthly	Fifth day of previous month	RLDC & RPC
Yearly	31st October of the previous year	RLDC & RPC

60.2.2. **POSOCO** suggested replacing "31st August" with "31st September" in the table, aligned with Chapter 2.

60.3. **Analysis and Decision**

60.3.1. The suggestions of POSOCO have been accepted.

60.3.2. With regard to suggestions of SRPC, it is clarified that daily estimation on a day ahead basis may provide the most accurate data, and additional data for 'D-2' may not be required.

60.3.3. The draft regulation has been modified as 31 (2) (h) in the 2023 Grid Code Regulations as follows:

"(h) Timeline for submission of demand estimate data by SLDCs or other entities directly connected to ISTS, as applicable, to the respective RLDC and RPC shall be as follows:

Table 5: Timeline for Demand Estimation

Daily demand estimation	*10:00 hours of previous day*
Weekly demand estimation	*First working day of previous week*
Monthly demand estimation	*Fifth day of previous month*
Yearly demand estimation	*30th September of the previous year*

61. Operational Planning (Regulation 31 (2)(h))

61.1. **Commission's Proposal**

61.1.1. The Commission had proposed the following in Regulation 31 (2)(h) of the Draft Regulations:

"(h) SLDCs, RLDCs and NLDC shall compute forecasting error for daily, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in future. The computed forecasting errors shall be made available by SLDCs, RLDCs and NLDC on their respective websites."

61.2. **Comments have been received from SRPC, MSEDCL and POSOCO**

61.2.1. **SRPC**, suggested inserting the sentence "A report on yearly forecast errors including the action plan for improving the same shall be submitted to appropriate Commission" at the end of the clause to ensure accountability and improve the forecast errors.

61.2.2. **MSEDCL** suggested that it is necessary that separate guidelines for demand estimation of RE-rich states may be issued by appropriate forums so as to bring uniformity in demand estimation by all States/DISCOMs. MSEDCL further suggested that an Energy Storage System (ESS) may also be included as a part of renewable energy sources to maintain the peak demand of the area, and the demand forecasting may be estimated considering the charging/ discharging of the ESS cycle.

61.2.3. **POSOCO** suggested replacing the word "daily" with "intra-day" as day-ahead will cover the daily also.

61.3. **Analysis and Decision**

61.3.1. With regard to suggestions of SRPC, it is clarified that once the data on forecasting errors is uploaded on websites along with the provision of analysing the same to reduce errors in the future, the need for a separate report does not arise.

61.3.2. The suggestions to include guidelines for demand estimation are already included in Chapter-2 of the 2023 Grid Code. Commission has noted the suggestions of the stakeholders.

61.3.3. Suggestions of POSOCO have been accepted.

61.3.4. The draft regulation has been modified as 31 (2) (i) in the 2023 Grid Code Regulations as follows,

"(i) SLDCs, RLDCs and NLDC shall compute forecasting error for <u>intra-day</u>, day ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in the future. The computed forecasting errors shall be made available by SLDCs, RLDCs and NLDC on their respective websites."

62. Operational Planning (Regulation 31 (3)(b))

62.1. **Commission's Proposal**

62.1.1. The Commission had proposed the following in Regulation 31 (3)(b) of the Draft Regulations:

"(b) RLDC shall forecast generation from wind and solar generating stations which are regional entities for different time horizons as referred to in clause (1) of Regulation 31 of these regulations for the purpose of operational planning."

62.2. **Comments have been received from SRPC and POSOCO**

62.2.1. **SRPC**, suggested substituting the word "RLDC/SLDC" for "RLDC" and the words "regional /state entities" for "regional entities".

62.2.2. **POSOCO** suggested including a Hybrid generating station for forecast by RLDC.

62.3. **Analysis and Decision**

62.3.1. The suggestions of SRPC and POSOCO have been accepted.

62.3.2. Regulation 31 (3) (b) of the 2023 Grid Code Regulations have been modified as follows:

"(b) RLDC shall forecast generation from wind, solar, ESS and Renewable Energy hybrid generating stations that are regional entities and SLDC shall forecast generation from such sources that are intra-state entities, for different time horizons as referred to in clause (1) of Regulation 31 of these regulations for the purpose of operational planning."

63. Operational Planning (Regulation 31 (4)(b))

63.1. **Commission's Proposal**

63.1.1. The Commission had proposed the following in Regulation 31 (4)(b) of the Draft Regulations:

"(b) SLDCs shall furnish time block-wise information for the following day in respect of all intra-state entities to the concerned RLDC who shall validate adequacy of resources with due regard to the following:

(i) Demand forecast aggregated for the control area;

(ii) Renewable energy generation forecast for the control area;

(iii) Injection schedule for intra-State entity generating station;

(iv) Requisition from regional entity generating stations."

63.2. **Comments have been received from SRPC and POSOCO**

63.2.1. **SRPC** has suggested including the following points under this clause:

- Purchase planned from DAM & RTM
- SRAS & TRAS

63.2.2. **POSOCO** suggested adding the following additional sub clause (v) and proviso for this Regulation 31(4)(b):

"(v) Specific zones of the control areas where the power factor is low and voltage issues have been observed.

Provided that ISTS connected entities shall furnish the similar details as above."

63.3. **Analysis and Decision**

63.3.1. Considering suggestions of SRPC, two new sub-clauses have been inserted as (v) and (vi) under Regulation 31 (4) (b) of the 2023 Grid Code Regulations as follows:

"(b) SLDCs shall furnish time block-wise information for the following day in respect of all intra-state entities to the concerned RLDC who shall validate the adequacy of resources with due regard to the following:

(i) Demand forecast aggregated for the control area;

(ii) Renewable energy generation forecast for the control area;

(iii) Injection schedule for intra-State entity generating station;

(iv) Requisition from regional entity generating stations;

<u>(v) Secondary and planned procurement through Tertiary reserve requirement;</u>

<u>(vi) Planned procurement of power through other bilateral or collective transactions, if any."</u>

63.3.2. Any additional data requirement of POSOCO such as low power factor may be obtained by RLDC under the Operating Procedure based on state specific issues.

64. Outage Planning (Regulation 32 (2)(c))

64.1. **Commission's Proposal**

64.1.1. The Commission had proposed the following in Regulation 32 (2)(c) of the Draft Regulations:

"(c) The outage plan of hydro generation plant, wind and solar generation plant and its associated evacuation network shall be prepared with a view to extract maximum generation from these sources.

Example: Outage of wind generator shall be planned during lean wind season. Outage of solar generator, if required, shall be planned during the rainy season. Outage of hydro generator could be planned during the lean water season."

64.2. **Comments have been received from SRPC and OTPC**

64.2.1. **SRPC** has suggested modifying the clause as Wind and solar outages are coordinated by the respective developers to achieve maximum availability, and as such, there is no outage planning for these resources:

"(c) The outage plan for <u>regional entity wind, solar, hybrid generation and ESS</u> and its associated evacuation network shall be prepared <u>by the respective entity and furnished to RPC</u>."

64.2.2. **OTPC** has requested the Commission that the outage of thermal units be planned by respective RPCs in a way that the outage may not fall during high demand period, and if a high demand period falls during a high hydro period or overlaps the same, RPCs may be directed to consider suitable alternative so that stations do not suffer AFC loss.

64.3. **Analysis and Decision**

64.3.1. It is observed that the outage plan needs to be finalised at the RPC level. Any inputs regarding outage planning may be obtained from the concerned entity by the RPC as required.

64.3.2. Regulation 32 (2) (c) of the 2023 Grid Code Regulations have been modified as follows:

"(c) The outage plan of hydro generation plants, <u>REGS and ESS</u> and its associated evacuation network shall be prepared with a view to extracting maximum generation from these sources.
Example: Outage of wind generator may be planned during lean wind season. Outage of solar generator, if required, may be planned during the rainy season. Outage of hydro generator may be planned during the lean water season."

65. Outage Planning (Regulation 32 (2)(d))

65.1. **Commission's Proposal**

65.1.1. The Commission had proposed the following in Regulation 32 (2)(d) of the Draft Regulations:

"(d) Protection relay related outages, auto–re-closure outages and SPS testing outages shall be planned on monthly basis with prior permission of the concerned RPC, which shall consult the concerned RLDC & NLDC."

65.2. **Comments have been received from SRPC and HPSLDC**

65.2.1. **SRPC** suggested adding the following new sub-clause to avoid voluminous outage planning:

"(e) For Intra-state network, RPCs will finalize the outage plan of 400 kV and above (220 kV and above for NER), interstate links and important elements identified under Regulation 39(2)(b). RPCs shall plan the outages of generating units 50 MW and above."

65.2.2. **HPSLDC** suggested that the concerned SLDC may also be informed in such cases.

65.3. **Analysis and Decision**

65.3.1. With regard to suggestions of SRPC, it has been provided under Regulation 32(2)(a) that for elements under the State Control area, the outage plan shall be prepared only for the identified elements under Regulation 29(2)(b) of the 2023 Grid Code.

65.3.2. The provision as proposed in the Draft Regulations has been retained.

66. Outage Planning (Regulation 32 (3)(b))

66.1. **Commission's Proposal**

66.1.1. The Commission had proposed the following in Regulation 32 (3)(b) of the Draft Regulations:

"(b) RPCs shall prepare LGBR based on the LGBR submitted by SLDCs for their respective states and shall prepare annual outage plan for generating units and transmission elements in their respective region after carrying out necessary system studies in order to ensure system security and resource adequacy."

66.2. **Comments have been received from SRPC**

66.2.1. **SRPC** suggested that Regional Entity Generators/ISTS Transmission Licensees may also be included for providing LGBR to RPC as much of the data is furnished by Regional Entities for LGBR preparation.

66.3. **Analysis and Decision**

66.3.1. The suggestion of SRPC has been accepted. Regulation 32 (3) (b) of the 2023 Grid Code Regulations has been modified as follows:

"(b) RPCs shall prepare Load Generation Balance Report (LGBR) for the respective region based on the LGBR submitted by SLDCs for their respective states <u>and the data submitted by the regional entity generating stations, inter-State transmission licensees and other entities directly connected to IS</u>TS in such format as may be stipulated by the RPCs and shall prepare annual outage plan for generating units and transmission elements in their respective region after carrying out necessary system studies in order to ensure system security and resource adequacy."

67. Outage Planning (Regulation 32 (3)(c), (d), (e) & (f))

67.1. **Commission's Proposal**

67.1.1. The Commission had proposed the following in Regulation 32 (3)(c), (d), (e) & (f) of the Draft Regulations:

"(c) RPCs shall finalize the outage plans in consultation with NLDC and respective RLDCs. The final outage plan and the final LGBR shall be intimated to NLDC, concerned RLDC, Users, STUs, CTU, the generating stations connected to the ISTS. The final outage plan and the final LGBR shall be made available on the websites of the respective users, RPCs, RLDCs and NLDC.

(d) The timeline for Outage Planning Process shall be as follows:

TABLE 6: TIMELINE FOR OUTAGE PLANNING PROCESS

Activity	*Agency*	*Cut-off date*
Submission of proposed outage plan for the next financial year to RPC with the earliest start date and latest finishing date	*CTU, STUs, transmission licensees and generating stations*	*31st October*
Submission of LGBR of the control area to RPC for both peak and off-peak scenarios	*SLDC*	*31st October*
Publishing draft LGBR and draft outage plan of regional grid for next financial year on the concerned RPC's website for inviting suggestions, comments, objections etc of stakeholders.	*RPC*	*30th November*
Publishing final LGBR and final outage plan of regional grid for next financial year on the concerned RPC's website	*RPC*	*31st December*

(e) The annual outage plan shall be reviewed by RPC on monthly and quarterly basis in coordination with all the parties concerned, and adjustments shall be made wherever necessary.

(f) All users, CTU, STUs, licensees shall follow the annual outage plan. If any deviation is required, the same shall be allowed only with prior permission of the concerned RPC, which shall consult the concerned RLDC and NLDC."

67.2. **Comments have been received from CTU, Power Grid, POSOCO and SRPC**

67.2.1. **CTU** commented on sub-clause (c) clause (d) and clause (f) that CTU shall be removed from these clauses as Outage planning for transmission system is carried out for approval of outages in real time operation by RPC in consultation with NLDC/RLDCs.

67.2.2. **Power Grid** in respect of Regulation 32(3)(e) has commented that an outage for bay maintenance activity may be concurred on a D-1 basis wherever power flow is not affected.

67.2.3. **POSOCO** suggested adding the word "or addition of new outages" after the words "and adjustments".

67.2.4. **SRPC** suggested modifying the clause (f) as under

"(f) … concerned RPC, which shall <u>be discussed in OCC of RPC and if the shutdown is before next OCC, RLDC shall consult the NLDC and concerned RPC</u>."

67.3. **Analysis and Decision**

67.3.1. The suggestion of POSOCO and CTU has been accepted.

67.3.2. Regarding suggestions of SRPC, it is clarified that the instant Regulation covers outage planning on a year ahead basis and sub-clause (e) covers the adjustments as required.

67.3.3. The suggestions of Powergrid to take concurrence are covered under sub-clause (g).

67.3.4. Regulation 32 (3) (d) & (e) of the 2023 Grid Code Regulations have been modified as follows:

"(d) The timeline for Outage Planning Process shall be as follows:

TABLE 5: TIMELINE FOR OUTAGE PLANNING PROCESS

Activity	***Agency***	***Cut-off date***
Submission of proposed outage plan for the next financial year to RPC with the earliest start date and latest finishing date	*STUs, transmission licensees and generating stations and other entities directly connected to ISTS*	*31st October*
Submission of LGBR of the control area to RPC for both peak and off-peak scenarios	*SLDC*	*31st October*
Publishing draft LGBR and draft outage plan of regional grid for next financial year on the concerned RPC's website for inviting suggestions, comments, objections of stakeholders.	*RPC*	*30th November*
Publishing final LGBR and final outage plan of regional grid for next financial year on the concerned RPC's website	*RPC*	*31st December*

(e) The annual outage plan shall be reviewed by RPC on a monthly and quarterly basis in coordination with all the parties concerned, and adjustments <u>or additions of new outages</u> shall be made wherever necessary."

68. Outage Planning (Regulation 32 (3)(g))

68.1. **Commission's Proposal**

68.1.1. The Commission had proposed the following in Regulation 32 (3)(g) of the Draft Regulations:

"(g) Each user shall obtain the final clearance from NLDC or the concerned RLDC, prior to the planned outage of any grid element. All deviations from the outage plan shall be uploaded on the RPC website."

68.2. **Comments have been received from SRPC**

68.2.1. **SRPC** suggested adding 'SLDC '

68.3. **Analysis and Decision**

68.3.1. The suggestion of SRPC has been accepted. Regulation 32 (3) (g) of the 2023 Grid Code Regulations has been modified as follows:

"(g) Each user shall obtain the final clearance from NLDC or the concerned RLDC, prior to the planned outage of any grid element. The clearance shall also be obtained from SLDC for a grid element of the State Control areas. All deviations from the outage plan shall be uploaded on the RPC website."

69. Outage Planning (Regulation 32 (3)(h)(i))

69.1. **Commission's Proposal**

69.1.1. The Commission had proposed the following in Regulation 3 (3)(h)(i) of the Draft Regulations:

"(i) NLDC or RLDC, as the case may be, shall have the authority to defer the planned outage;"

69.2. **Comments have been received from SRPC and NTPC**

69.2.1. **SRPC** suggested including SLDC also in this clause as mentioned in sub-clause (ii) of this Regulation.

69.2.2. **NTPC** commented that as per 2019-24 tariff regulations, capacity charges are recovered separately for High and Low demand seasons. Deferment of planned outages may affect adversely the recovery of fixed charges. Therefore, such deferment should be considered as 100% deemed availability or actual availability achieved during the deferred period of the machine when the actual shutdown of the machine is taken. Accordingly, NTPC suggested adding the following provision to the clause:

"Provided on such deferment generator shall be entitled to deemed availability during the period of shut down corresponding to actual availability achieved during the deferred period."

69.3. **Analysis and Decision**

69.3.1. The suggestion of SRPC to insert 'SLDC' has been accepted.

69.3.2. The issue of deemed availability, if any, pertains to Tariff Regulations and beyond the scope of 2023 Grid Code.

69.3.3. Regulation 32 (3) (h) (i) of the 2023 Grid Code Regulations have been modified as follows:

"(i) NLDC, RLDC or SLDC, as the case may be, shall have the authority to defer the planned outage;"

70. Outage Planning (Regulation 32 (4))

70.1. **Commission's Proposal**

70.1.1. The Commission had proposed the following in Regulation 32 (4) of the Draft Regulations:

"(4) To facilitate coordinated planned outages of grid elements, a common outage planning procedure shall be formulated by each RPC in consultation with NLDC and concerned RLDC."

70.2. **Comments have been received from SRPC**

70.2.1. **SRPC** suggested inserting at the end of this clause "and users.

70.3. **Analysis and Decision**

70.3.1. The suggestions of SRPC have been accepted. Regulation 32 (4) of the 2023 Grid Code Regulations has been modified as follows:

"(4) To facilitate coordinated planned outages of grid elements, a common outage planning procedure shall be formulated by each RPC in consultation with the NLDC, concerned RLDC and concerned users."

71. Operational Planning Study (Regulation 33 (1))

71.1. **Commission's Proposal**

71.1.1. The Commission had proposed the following in Regulation 33 (1) of the Draft Regulations:

"(1) Based on the operational planning analysis data, operational planning study shall be carried out by various agencies for time horizons as under:

TABLE 7: TIME HORIZON FOR OPERATIONAL PLANNING STUDY

Time horizon of operational planning study	*Agency*	*Means for carrying out study*
Real time and Intra-day	*NLDC, RLDC, and SLDC*	*At least fifteen (15) minutes interval using online/offline SCADA/EMS system*

….

71.2. **Comments have been received from POSOCO**

71.2.1. **POSOCO** suggested removing the provision of "at least 15 minutes interval" from Real time and intra-day i.e. the 2nd row of the table.

71.3. **Analysis and Decision**

71.3.1. The suggestions of POSOCO have been accepted. The time interval and need may be decided by NLDC, RLDC, and SLDC.

71.3.2. Regulation 33 (1) of the 2023 Grid Code Regulations has been modified as follows:

"(1) Based on the operational planning analysis data, operational planning study shall be carried out by various agencies for time horizons as under:

TABLE 6: TIME HORIZON FOR OPERATIONAL PLANNING STUDY

Time horizon of operational planning study	*Agency*	*Means for carrying out study*
Real time and Intra-day	*NLDC, RLDC, and SLDC*	*For various operating conditions using online/offline SCADA/EMS system*

..

72. Operational Planning Study (Regulation 33 (4)(a))

72.1. **Commission's Proposal**

72.1.1. The Commission had proposed the following in Regulation 33 (4)(a) of the Draft Regulations:

"(a) assessment of TTC and ATC at inter-regional, intra-regional and inter-state level;"

72.2. **Comments have been received from SRPC**

72.2.1. **SRPC** suggested removing "inter-state level" and adding the following to the clause to be in line with GNA Regulations:

"bid areas of power exchanges and inter-state level month-wise for one year on rolling basis; TTC/ATC shall be published on RLDC/NLDC website with all the assumptions and limiting constraints;"

72.3. **Analysis and Decision**

72.3.1. The suggestion to add 'bid areas' is not accepted. TTC and ATC at any additional level shall be decided by RLDC/NLDC as the need arises. The provision as proposed in the Draft Regulations has been retained.

73. Operational Planning Study (Regulation 33 (5))

73.1. **Commission's Proposal**

73.1.1. The Commission had proposed the following in Regulation 33 (5) of the Draft Regulations:

"(5) RLDC shall assess intra-regional and inter-state level TTC and ATC and submit to NLDC. NLDC shall declare TTC and ATC for import or export of electricity between regions including simultaneous import or export capability for a region and cross-border interconnections 11 (Eleven) months in advance for each of the month on a rolling basis. TTC and ATC shall be revised from time to time based on commissioning of new elements and other grid conditions and shall be published on the websites of NLDC and respective RLDCs with all the assumptions and limiting constraints."

73.2. **Comments have been received from POSOCO**

73.2.1. **POSOCO** suggested deleting the words "11 (Eleven) months" to keep Flexibility. Further, an Amendment may be needed in CERC procedure on measures to relieve congestion in real time operation.

73.3. **Analysis and Decision**

73.3.1. The period of 11 months has been retained considering the time period of 11 months under T-GNA. The provision as proposed in the Draft Regulations has been retained. The changes required in CERC procedure on measures to relieve congestion in real time operation shall be carried out in due course of time.

74. Operational Planning Study (Regulation 33 (6))

74.1. **Commission's Proposal**

74.1.1. The Commission had proposed the following in Regulation 33 (6) of the Draft Regulations:

"(6) Operational planning study shall be done to assess whether the planned operations shall result in deviations from any of the system operational limits defined under these regulations and applicable CEA Standards."

74.2. **Comments have been received from WRPC**

74.2.1. **WRPC** has suggested the insertion of the following in the clause,

"The deviations if any may be put up by RLDC to RPC in the monthly Operation sub-Committee meeting of the RPCs for its review. RPC may propose actions against the Utilities who are Persistently deviating and shall inform the deviations to CERC."

74.3. **Analysis and Decision**

74.3.1. Suggestions of WRPC have been accepted and Regulation 33 (6) of the 2023 Grid Code Regulations have been modified as follows:

"(6) Operational planning study shall be done to assess whether the planned operations shall result in deviations from any of the system operational limits defined under these regulations and applicable CEA Standards. <u>The deviations, if any, shall be reviewed in the monthly operational meeting of RPC and significant deviations shall be monitored by RPC for early resolution</u>."

75. Operational Planning Study (Regulation 33 (7))

75.1. **Commission's Proposal**

75.1.1. The Commission had proposed the following in Regulation 33 (7) of the Draft Regulations:

"(7) NLDC, RLDCs, RPCs and SLDCs shall maintain records of the completed operational planning study, including dated power flow study results, operational plan and minutes of meetings on operational study."

75.2. **Comments have been received from POSOCO**

75.2.1. **POSOCO** suggested deleting the word "dated".

75.3. **Analysis and Decision**

75.3.1. The word 'dated' has been provided to ensure that the database of power flow study results clearly includes the date when such studies were carried out since the study results vary with changes in data inputs. The provisions as proposed in the Draft Regulations have been retained.

76. Operational Planning Study (Regulation 33 (8))

77. Operational Planning Study (Regulation 33 (9), (10))

77.1. **Commission's Proposal**

77.1.1. The Commission had proposed the following in Regulation 33 (9) and (10) of the Draft Regulations:

"(9) Each SLDC shall undertake study on the impact of new elements to be commissioned in intra-state system in the next six (6) months on the TTC and ATC for the State.

(10) Each RLDC shall undertake study on the impact of new elements to be commissioned in the next six (6) months in (a) the ISTS of the region and (b) the intra-state system on the inter-state system"

77.2. **Comments have been received from POSOCO**

77.2.1. **POSOCO** suggested adding the words "and share the results of the studies with RLDC" at the end of the Regulation 33(9) and 33(10).

77.3. **Analysis and Decision**

77.3.1. The suggestions of POSOCO have been accepted. Regulation 33 (9) & (10) of the 2023 Grid Code Regulations have been modified as follows:

"(9) Each SLDC shall undertake a study on the impact of new elements to be commissioned in the intra-state system in the next six (6) months on the TTC and ATC for the State <u>and share the results of the studies with RLDC</u>.

(10) Each RLDC shall undertake a study on the impact of new elements to be commissioned in the next six (6) months in (a) the ISTS of the region and (b) the intrastate system on the inter-state system and share the results of the studies with NLDC."

78. Operational Planning Study (Regulation 33 (12))

78.1. **Commission's Proposal**

78.1.1. The Commission had proposed the following in Regulation 33 (12) of the Draft Regulations:

"(12) NLDC, RLDCs and SLDCs shall compare the results of the studies of impact of new elements on the system and transfer capability addition with those of the interconnection and planning studies by CTU and STUs, and any significant variations observed shall be communicated to CTU and STUs for immediate and long-term mitigation measures."

78.2. **Comments have been received from SRPC and HPSLDC**

78.2.1. **SRPC** suggested inserting the words "CEA, RPC" before the words "CTU and STUs" in the clause.

78.2.2. **HPSLDC** commented that any significant variations in the studies may be reviewed and submitted to the RPC for final decision.

78.3. **Analysis and Decision**

78.3.1. The suggestions of SRPC and HPSLDC have been accepted.

78.3.2. Regulation 33 (12) of the 2023 Grid Code Regulations has been modified as follows:

"(12) NLDC, RLDCs and SLDCs shall compare the results of the studies of the impact of new elements on the system and transfer capability addition with those of the interconnection and planning studies by CTU and STUs, and any significant variations observed shall be communicated to CEA, RPCs, CTU and STUs for immediate and long-term mitigation measures."

79. System Restoration (Regulation 34 (3))

79.1. **Commission's Proposal**

79.1.1. The Commission had proposed the following in Regulation 34 (3) of the Draft Regulations:

"(3) Detailed procedures for restoration post partial and total blackout of each user system within a region shall be prepared by the concerned user in coordination with the concerned SLDC, RLDC or NLDC, as the case may be. The concerned user shall review the procedure every year and update the same. The user shall carry out mock trial run of the procedure for different sub-systems including black-start of generating units along with grid forming capability of inverter based generating station, VSC based HVDC black-start support at least once in a year under intimation to the concerned SLDC and RLDC. Diesel generator sets and other standalone auxiliary supply source to be used for black start shall be tested on weekly basis and the user shall send the test reports to concerned SLDC, RLDC and NLDC on a quarterly basis."

79.2. **Comments have been received from NHPC, KPTCL, and Power Grid**

79.2.1. **NHPC** commented that submission of each test report of Diesel generator sets and another standalone auxiliary supply source to be used for black start to concerned SLDC, RLDC, and NLDC should unnecessarily require extra manpower and time.

79.2.2. **KPTCL** commented that the Mock trial run, including the black—start of generating units is not possible. Hence, it may be removed.

79.2.3. **Power Grid** suggested that the user shall carry out a mock trial run at least once in five years instead of once in a year. Power Grid, during a public hearing of the Draft IEGC Grid Code, has commented that since VSC HVDC works on Power electronic converters, an annual mock drill of the black-start scenario is not envisaged as once the VSC black-start feature has been tested during the commissioning, the performance does not alter/drift over time, unlike synchronous generators where mechanical parts are involved.

79.3. **Analysis and Decision**

79.3.1. The restoration of grid post blackout is one of the most important requirements of the grid and should be well tested. Accordingly, the suggestions not to carry out mock run are rejected.

79.3.2. The provision as proposed in the Draft Regulations has been retained.

80. System Restoration (Regulation 34 (5))

80.1. **Commission's Proposal**

80.1.1. The Commission had proposed the following in Regulation 34 (5) of the Draft Regulations:

"(5) The thermal and nuclear generating stations shall be prepared for house load operation as per design. Concerned user and SLDC shall report the performance of house load operation of a generating station in the event where such operation was required."

80.2. **Comments have been received from SRPC, POSOCO, Sembcorp and OTPC**

80.2.1. **SRPC** and **POSOCO** suggested replacing the word "design" with "CEA Technical Standards for Construction Regulations". Further, SRPC suggested that the word SLDC be substituted by "RLDC/SLDC".

80.2.2. **Sembcorp** commented that for Sembcorp's thermal plants and other thermal power plants may not be able to operate on house load. This clause should not be made mandatory on all plants but should be applicable only for plants which are capable of such operation.

80.2.3. **OTPC** has suggested that OTPC GT can run on house load. However, ST cannot run on a house load. Palatana plant can operate only under combined cycle mode (due to the absence of a diverter damper). So, when GT comes on house load, load on GT can only be increased after synchronization of ST.

80.3. **Analysis and Decision**

80.3.1. With regard to suggestions of SRPC and POSOCO, it is observed that there are conflicting comments received from POSOCO and the generating units. Accordingly, it is clarified that house load operation as per design is mandated. CEA Standards are to be complied with by all generating units.

80.3.2. The provision as proposed in the Draft Regulations has been retained.

81. System Restoration (Regulation 34 (9))

81.1. **Commission's Proposal**

81.1.1. The Commission had proposed the following in Regulation 34 (9) of the Draft Regulations:

"(9) Any entity extending black start support by way of injection of power as identified in clause (6) of this Regulation shall be paid for actual injection @ 110 % of normal rate of charges for deviation in accordance with DSM Regulations for the last block in which the grid was available."

81.2. **Comments have been received from SRPC, SJVNL and Tata Power**

81.2.1. **SRPC** suggested inserting the sentence "The procedure in this regard shall be prepared by NLDC in consultation with stakeholders" at the end of this clause, as the Procedure would help in addressing the finer details.

81.2.2. **SJVNL** suggested that the Commission may also notify the additional incentive to the generators for operating in adverse conditions during the Black Start Exercise.

81.2.3. **Tata Power** commented that if a, black start unit like a gas plant, uses high value fuel like RLNG, the compensation based on DSM may not be sufficient and, therefore, provision for such cases may also be made.

81.3. **Analysis and Decision**

81.3.1. The suggestions of SRPC have been accepted.

81.3.2. With regard to suggestions of Tata Power, it is clarified that compensation has been introduced in the 2023 Grid Code irrespective of type of generating station. In case the need arises, a framework for black start as an ancillary service may be provided for in Ancillary Service Regulations in due course of time.

81.3.3. Regulation 34 (9) of the 2023 Grid Code Regulations has been modified as follows,

"(9) Any entity extending black start support by way of injection of power as identified in clause (6) of this Regulation shall be paid for actual injection @ 110 % of the normal rate of charges for deviation in accordance with DSM Regulations for the last block in which the grid was available. <u>The procedure in this regard shall be prepared by NLDC in consultation with stakeholders and approved by the Commission."</u>

82. Real Time Operation (Regulation 35 (1)(b))

82.1. **Commission's Proposal**

82.1.1. The Commission had proposed the following in Regulation 35 (1)(b) of the Draft Regulations:

"(b) Alert state

Power system shall be categorized under alert sate when the power system is operating with operational parameters within their respective operational limits, but a single contingency leads to violation of security criteria. The power system remains intact under *such alert state. However, whenever the power system is under alert sate, the system operator shall take corrective measures to bring back the power system to normal state.*

82.2. **Comments have been received from POSOCO**

82.2.1. **POSOCO** suggested substituting the word “single contingency” with “N-1 contingency”.

82.3. **Analysis and Decision**

82.3.1. The suggestions of POSOCO have been accepted.

82.3.2. Regulation 35 (1) (b) of the 2023 Grid Code Regulations has been modified as follows,

“(b) Alert state
Power system shall be categorized under alert sate when the power system is operating with operational parameters within their respective operational limits, but a single contingency <u>(‘N-1’)</u> leads to a violation of security criteria. The power system remains intact under such alert state. However, whenever the power system is under alert sate, the system operator shall take corrective measures to bring it back to a normal state.”

83. Real Time Operation (Regulation 35 (5)(b))

83.1. **Commission’s Proposal**

83.1.1. The Commission had proposed the following in Regulation 35 (5)(b) of the Draft Regulations:

“(b) Any planned operation activity in ISTS system [such as transmission element opening or closing (including breakers), protection system outage, SPS outage and testing etc.] shall be done by taking operational code from RLDC or NLDC, as the case may be. The operational code shall have validity period of thirty (30) minutes from the time of issue. In case such operation activity does not take place within the validity period of the code, the entity shall obtain a fresh operational code from RLDC or NLDC, as the case may be.”

83.2. **Comments have been received from SRPC, Power Grid and MP Power Management Company**

83.2.1. **SRPC** suggested adding “unit synchronization/desynchronization” to the list of ISTS system elements mentioned in the clause.

83.2.2. **Power Grid** commented that in winter, a lot of lines are opened on voltage regulation and the 30 min deadline can be hard to meet; therefore, it is suggested increasing the validity period of operational code from 30 minutes to 60 minutes.

83.2.3. **MP Power Management Company** commented that such provision was not present in the existing Code and any such activity has to be done with operational Code issued by RLDC or NLDC. It is suggested that either the existing provision should be continued as per the CEA Regulations or a reference of standard should be provided that has been considered for the proposed provision.

83.3. **Analysis and Decision**

83.3.1. The suggestions of SRPC and Powergrid have been accepted.

83.3.2. With regard to suggestions of MPPMCL, it is clarified that operational code was taken from RLDC/NLDC even under the 2010 Grid Code. The practice has been formalised in the 2023 Grid Code for information and compliance of all entities.

83.3.3. Regulation 35 (5) (b) of the 2023 Grid Code Regulations have been modified as follows,

"(b) Any planned operation activity in the ISTS system [such as <u>generating unit synchronization or de-synchronization</u>, transmission element opening or closing (including breakers), protection system outage, SPS outage and testing etc.] shall be done by taking operational code from RLDC or NLDC, as the case may be. The operational code shall have validity period of <u>sixty (60)</u> minutes from the time of issue. In case such operation activity does not take place within the validity period of the code, the entity shall obtain a fresh operational code from RLDC or NLDC, as the case may be."

84. Demand and Load Management (Regulation 36 (2)(a), (b))

84.1. **Commission's Proposal**

84.1.1. The Commission had proposed the following in Regulation 36 (2)(a), (b) of the Draft Regulations:

"(a) the respective distribution licensee shall abide by directions of SLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.

(b) SLDC or RLDC through SLDC may direct distribution licensee to restrict drawal from the grid or curtail load for ensuring the stability of the grid:

Provided that load shedding shall be resorted to after the demand response option has been exhausted."

84.2. **Comments have been received from SRPC and DVC**

84.2.1. **SRPC** suggested including the "bulk consumers connected to STU" in both the clauses along with respective distribution licensee, as Bulk Consumers connected to STU may also support the grid.

84.2.2. **DVC** commented that since DVC's feeders mostly supply power to the Steel industries, traction and coal mines, with few domestic feeders supplying to JBVNL and identification of specific feeders under different schemes namely, Demand Response, UFR & df/dt scheme, may not be possible in respect to DVC, also the spatial spread of feeders may not be feasible due to concentration of most of the Distribution feeders across Jharkhand area. According to DVC, requested to consider the same while finalizing the Load Relief Quantum in respect of DVC state.

84.3. **Analysis and Decision**

84.3.1. The suggestions of SRPC have been accepted.

84.3.2. With respect to suggestions of DVC it is clarified that under an alert or emergency state, all entities must abide by the instructions of RLDC/SLDC to bring back the system to a normal State, including DVC.

84.3.3. The draft regulation has been modified as 36 (3)(a), (b) & (c) in the 2023 Grid Code Regulations as follows,

"(a) <u>the respective distribution licensee or bulk consumer under the regional control area shall abide by the directions of the RLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.</u>
(b) the respective distribution licensee <u>under state control area</u> shall abide by the

directions of SLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.
(c) SLDC or RLDC through SLDC may direct distribution licensees or bulk consumers directly connected to STU, to restrict drawal from the grid or curtail load to ensure the stability of the grid:
Provided that load shedding shall be resorted to after the demand response option has been exhausted."

85. Post-Despatch Analysis (Regulation 37 (1)(a)(i))

85.1. **Commission's Proposal**

85.1.1. The Commission had proposed the following in Regulation 37 (1)(a)(i) of the Draft Regulations:

"(i) Pattern of demand met, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, ancillary services despatched, transmission congestion and (n-1) violations;"

85.2. **Comments have been received from SRPC**

85.2.1. **SRPC** suggested modifying the clause as,

"Pattern of demand met, under and over drawls, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, load and RE forecast errors, ancillary services despatched, transmission congestion and (n-1) violations;"

85.3. **Analysis and Decision**

85.3.1. The suggestions of SRPC have been accepted.

85.3.2. Regulation 37 (1) (a) (i) of the 2023 Grid Code Regulations have been modified as follows:

"(i) Pattern of demand met, under drawls and over drawls, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, load and RE forecast errors, ancillary services despatched, transmission congestion and (n-1) violations;"

86. Post-Despatch Analysis (Regulation 37 (b))

86.1. **Commission's Proposal**

86.1.1. The Commission had proposed the following in Regulation 37 (b) of the Draft Regulations:

"(b) Such analysis shall be disclosed on their respective website in formats issued by NLDC."

86.2. **Comments have been received from WRPC**

86.2.1. **WRPC** has commented that the analysis would be reviewed in the Operation Committee meeting of RPCs every month so that effective planning and its implementation can be ensured and has suggested adding the same in the regulation

86.3. **Analysis and Decision**

86.3.1. RPCs may use the analysis available on the website of NLDC/RLDC/SLDC for review in OCC as required. The provision as proposed in the Draft Regulations has been retained.

87. Post-Despatch Analysis (Regulation 37 (2)(f))

87.1. **Commission's Proposal**

87.1.1. The Commission had proposed the following in Regulation 37 (2)(f) of the Draft Regulations:

"(f) RLDCs and NLDC (for events involving more than one region) shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis which shall be discussed and finalized at Protection sub-committee of RPC as per timeline specified in the table below"

TABLE 8: REPORT SUBMISSION TIMELINE

Sr. No.	*Grid Event^ (Classification)*	*Flash report submission deadline (users/ SLDC)*	*Disturbance record and station event log submission deadline (users/ SLDC)*	*Detailed report and data submission deadline (users/ SLDC)*	*Draft report submission deadline (RLDC/ NLDC)*	*Discussion in protection committee meeting and final report submission deadline (RPC)*
1	*GI-1/GI-2*	*8 hours*	*24 hours*	*+7 days*	*+14 days*	*+30 days*
2	*Near miss***	*8 hours*	*24 hours*	*+7 days*	*+30 days*	*+30 days*
3	*GD-1*	*8 hours*	*24 hours*	*+7 days*	*+14 days*	*+30 days*
4	*GD-2/GD-3*	*8 hours*	*24 hours*	*+7 days*	*+21 days*	*+30 days*
5	*GD-4/GD-5*	*8 hours*	*24 hours*	*+7 days*	*+30 days*	*+30 days*

^The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per the CEA (Grid Standards) Regulations, 2010.

**Near miss event means an incident of multiple failures that had the potential to cause a grid disturbance, power failure or partial collapse but did not result in a grid disturbance.*

87.2. **Comments have been received from SRPC and POSOCO**

87.2.1. **SRPC** suggested that the "Near miss" row and definition be deleted as they are already covered in GI. SRPC has also suggested that days in the last column (Discussion in protection committee meeting and final report submission deadline (RPC) may be modified as "+60 days".

87.2.2. **POSOCO** suggested the following modification in the table and adding the following Note under this clause, the days mentioned in the column "Draft Report submission deadline (RLDC/NLDC)" shall be modified as +7 days for Sr. No. 1,2 & 3.

"Note: The reference day for the report submission would be the previous deadline/ preceding column"

87.3. **Analysis and Decision**

87.3.1. The suggestions of SRPC have been accepted. The timeline for submission of a draft report by RLDC/NLDC has been reduced to 7 days after detailed submissions by users/SLDC under Serial Numbers 1,2,3.

87.3.2. Regulation 37 (2) (f) of the 2023 Grid Code Regulations have been modified as follows:

"(f) RLDCs and NLDC (for events involving more than one region) shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis which shall be discussed and finalized at the Protection subcommittee of RPC as per the timeline specified in Table-8 below.

TABLE 8: REPORT SUBMISSION TIMELINE

Sr. No.	*Grid Event^ (Classification)*	*Flash report submission deadline (users/ SLDC)*	*Disturbance record and station event log submission deadline (users/ SLDC)*	*Detailed report and data submission deadline (users/ SLDC)*	*Draft report submission deadline (RLDC/ NLDC)*	*Discussion in protection committee meeting and final report submission deadline (RPC)*
1	*GI-1/GI-2*	*8 hours*	*24 hours*	*+7 days*	*+7 days*	*+60 days*
2	*Near miss event*	*8 hours*	*24 hours*	*+7 days*	*+7 days*	*+60 days*
3	*GD-1*	*8 hours*	*24 hours*	*+7 days*	*+7 days*	*+60 days*
4	*GD-2/GD-3*	*8 hours*	*24 hours*	*+7 days*	*+21 days*	*+60 days*
5	*GD-4/GD-5*	*8 hours*	*24 hours*	*+7 days*	*+30 days*	*+60 days*

^The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per the CEA Grid Standards.

88. Post-Despatch Analysis (Regulation 37 (2)(g))

88.1. Commission's Proposal

88.1.1. The Commission had proposed the following in Regulation 37 (2)(g) of the Draft Regulations:

"(g) The implementation of the recommendations of final report shall be monitored in the protection sub-committee of the RPC. NLDC shall disseminate the lessons learnt from each event to all the RPCs for necessary action in the respective regions."

88.2. Comments have been received from SRPC, POSOCO and CTU

88.2.1. **SRPC** suggested that NLDC shall also disseminate such information to CTU concurrently and also through Operational feedback.

88.2.2. **POSOCO** suggested adding the words "Monthly meetings may be held" at the end of this clause.

88.2.3. **CTU** has suggested that NLDC shall also disseminate such information to CTU concurrently and through Operational feedback. Feedback on lessons learnt from Grid disturbances/Incidences may also be given to CTU for information purposes to enable better transmission system planning.

88.3. Analysis and Decision

88.3.1. With regard to suggestions of SRPC and CTU for sharing the information with CTU, it is clarified that the reports shall be discussed at the Protection sub-committee of RPC, including CTU, and hence a separate provision is not required.

88.3.2. The periodicity of the meeting may be decided based on events at the RPC level.

88.3.3. The provision as proposed in the Draft Regulations has been retained.

89. Post Despatch Analysis (Regulation 37 (2)(i))

89.1. **Commission's Proposal**

89.1.1. The Commission had proposed the following in Regulation 37 (2)(i) of the Draft Regulations:

"(i) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during any event in the grid shall be reported to the concerned RLDC and RPC if connected to ISTS and to the concerned SLDC if connected to intra-state system. The transient fault records and event logger data shall be submitted to the concerned RLDC or SLDC within 24 hours of occurrence of the incident."

89.2. **Comments have been received from POSOCO**

89.2.1. **POSOCO** suggested adding the following sentence at the end of this clause:

"Generating stations shall submit 1 second resolution active power and reactive power data recorded during oscillations to the concerned RLDC or SLDC within 24 hours of occurrence of the oscillations."

89.3. **Analysis and Decision**

89.3.1. Considering suggestions of POSOCO, Regulation 37 (2) (i) of the 2023 Grid Code Regulations have been modified as follows:

"(i) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during any event in the grid shall be reported to the concerned RLDC and RPC if connected to ISTS and to the concerned SLDC if connected to an intra-state system. The transient fault records and event logger data shall be submitted to the concerned RLDC or SLDC within 24 hours of the occurrence of the incident. <u>Generating stations shall submit 1 second resolution active power and reactive power data recorded during oscillations to the concerned RLDC or SLDC within 24 hours of the occurrence of the oscillations</u>."

90. Post Despatch Analysis (Regulation 37 (2)(j))

90.1. **Commission's Proposal**

90.1.1. The Commission had proposed the following in Regulation 37 (2)(j) of the Draft Regulations:

"(j) A monthly report on events of unintended operation or non-operation of protection system shall be prepared and submitted by each user to concerned RPC and RLDC within the first week of the subsequent month."

90.2. **Comments have been received from POSOCO**

90.2.1. **POSOCO** suggested adding the words "(220 kV and above associated with important grid elements)" after the words "non-operation of".

90.3. **Analysis and Decision**

90.3.1. Considering suggestions of POSOCO, references to important grid elements have been inserted. Regulation 37 (2) (i) of the 2023 Grid Code Regulations has been modified as follows:

"(j) A monthly report on events of unintended operation or non-operation of the protection system shall be prepared and submitted by each user [owner of important elements as identified at sub-clause (b) of clause (2) of Regulation 29 of these regulations] to the concerned RPC and RLDC within the first week of the subsequent month."

91. Reactive Power Management (Regulation 39 (2))

91.1. **Commission's Proposal**

91.1.1. The Commission had proposed the following in Regulation 39 (2) of the Draft Regulations

"(2) All generating stations shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits as per the CEA Connectivity Standard Regulations".

91.2. **Comments have been received from NTPC and IEEMA-Copper Alliance**

91.2.1. **NTPC** has suggested that the CEA Grid Connectivity standard needs to be updated in line with Transmission Planning criteria. Accordingly, NTPC suggested adding "of 0.98" after "power factor" in the clause.

91.2.2. **IEEMA-Copper alliance** commented that instead of all generating stations providing individual reactive power support, can we include the provision of a single STATCOM/BESS to provide common reactive power support for multiple generating stations connected to a common pooling bus? STATCOM/BESS requirements can be a pre-requisite provision when multiple generating stations are/will be connected to a common pooling bus (forming a park).

91.3. **Analysis and Decision**

91.3.1. With regard to suggestions of NTPC, the range of power factors as per CEA Standards has been included in the Clause.

91.3.2. With regard to suggestions of IEEMA, it is clarified that since the compliance requirement is the interconnection point, multiple generating stations may provide such requirements in a combined manner so as to maintain the power factor at the interface point within the limits as per CEA Standards.

91.3.3. Regulation 39 (2) of the 2023 Grid Code Regulations has been modified as follows:

"(2) All generating stations shall be capable of supplying reactive power support so as to maintain power factor at the point of interconnection within the limits of 0.95 lagging to 0.95 leading as per the CEA Connectivity Standard Regulations."

92. Reactive Power Management (Regulation 39 (3))

92.1. **Commission's Proposal**

92.1.1. The Commission had proposed the following in Regulation 39 (3) of the Draft Regulations:

"(3) All generating stations connected to the grid shall generate or absorb reactive power as per instructions of the concerned RLDC or SLDC, as the case may be within capability limits of the respective generating units.
Explanation: Capability limit of a generating unit shall be as specified by the OEM."

92.2. **Comments have been received from TS Transco, KPTCL, and IEEMA-Copper Alliance**

92.2.1. **TS TRANSCO** and **KPTCL** suggested that a Commercial mechanism for reactive power exchanges from inverter based generation should also be introduced.

92.2.2. **IEEMA -Copper alliance** commented that there is no mention of reactive power support to be provided at POI. It is recommended to incorporate the quantum of reactive power to be absorbed at POI in the HVRT table mentioning Over-voltage and Minimum time duration to remain Connected.

Further, if the grid voltage drops to 0.85 pu at POI but inverter voltage is such that LVRT is not triggered. In that case, the reactive power injection may not be observed at POI. It is recommended to incorporate the quantum of reactive power to be injected at POI for the borderline cases like 0.85 pu.

92.3. **Analysis and Decision**

92.3.1. With regard to suggestions of KPTCL and TSTRANSCO, it is clarified that commercial mechanism for reactive power interchange as provided in Annexure-4 is applicable for all generating units including invertor based units.

92.3.2. With regard to suggestions of IEEMA, it is clarified that all the requirements are to be met at POI as specifically provided for in Regulation 39(2) and Annexure-4 of the 2023 Grid Code. The Commission has noted the suggestions of the stakeholders

92.3.3. Regulation 39 (3) of the 2023 Grid Code Regulations has been modified as follows:

"(3) All generating stations connected to the grid shall generate or absorb reactive power as per instructions of the concerned RLDC or SLDC, as the case may be, within the capability limits of the respective generating units, where capability limits shall be as specified by the OEM."

93. Reactive Power Management (Regulation 39 (4))

93.1. **Commission's Proposal**

93.1.1. The Commission had proposed the following in Regulation 39 (4) of the Draft Regulations:

"(4) NLDC, RLDCs or SLDCs may direct the users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at interconnection points."

93.2. **Comments have been received from KPTCL**

93.2.1. **KPTCL** suggested that in case of RE sources, since NLDC, RLDC or SLDC cannot direct individual RE generators with inverters, it is recommended to propose the stipulation for supply/absorption of reactive power is as below:

Voltage in % of rated nominal voltage	KVAR to be supplied/absorbed by solar Generator expressed as a % of KW generated.
95%	32.87% (from Generator to Grid)
96%	26.24% (from Generator to Grid)
97%	19.68% (from Generator to Grid)
98%	13.12% (from Generator to Grid)

99%	06.56% (from Generator to Grid)
100%	0%
101%	-06.56% (from Grid to Generator)
102%	-13.12% (from Grid to Generator)
103%	-19.68% (from Grid to Generator)
104%	-26.24% (from Grid to Generator)
105%	-.32.87% (from Grid to Generator)

Violation of the values stipulated as above, such Var exchanges in excess or less than the stipulated value, it is proposed to be compensated/penalized based on the rate of reactive power approved by CERC as stipulated in the Annexure-4 of the draft IEGC regulation 2022.

93.3. **Analysis and Decision**

93.3.1. With regard to suggestions of KPTCL it is clarified that Annexure-4 is applicable for all regional entity generators, including RE generators. Further calculation of reactive power for individual generators in case of generators connected in a park is provided for in Annexure-4 of the 2023 Grid Code as follows:

"(c)All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing reactive power support, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS.

(d)For IBRs of capacity 50 MW and below not coming directly to the point of interconnection but through the pooling at the Power Park Developer end, the Power Park Developer shall act as aggregator for the Reactive Energy Charges for payments to and from the Pool Account at RLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer."

93.3.2. The draft regulation has been retained in the 2023 Grid Code Regulations.

94. Reactive Power Management (Regulation 39 (5))

94.1. **Commission's Proposal**

94.1.1. The Commission had proposed the following in Regulation 39 (5) of the Draft Regulations:

"(5) NLDC, RLDCs and SLDCs shall assess the dynamic reactive power reserve available at various substations or generating stations under any credible contingency on a regular basis based on technical details and data provided by the users."

94.2. **Comments have been received from POSOCO**

94.2.1. **POSOCO** suggested adding the words "as per the procedure specified by NLDC" at the end of this clause.

94.3. **Analysis and Decision**

94.3.1. The suggestions of POSOCO have been accepted. The draft regulation has been modified as 39 (6) in the 2023 Grid Code Regulations as follows

"(6) NLDC, RLDCs and SLDCs shall assess the dynamic reactive power reserve available at various substations or generating stations under any credible contingency on a regular basis based on technical details and data provided by the users, <u>as per the procedure specified by NLDC.</u>"

95. Reactive Power Management (Regulation 39 (6))

95.1. **Commission's Proposal**

95.1.1. The Commission had proposed the following in Regulation 39 (6) of the Draft Regulations:

"(6) NLDC, RLDCs and SLDCs shall take appropriate measures to maintain the voltage within limits inter-alia using following facilities and facility owner shall abide by the instructions of NLDC, RLDCs and SLDCs:
(i) shunt reactors,
(ii) shunt capacitors,
(iii) TCSC,
(iv) VSC based HVDC,
(v) synchronous/non-synchronous generator voltage control,
(vi) synchronous condenser,
(vii) static VAR compensators (SVC), STATCOM and other FACTS devices,
(viii) transformer tap change: generator transformer and inter-connecting transformer,
(ix) HVDC power order or HVDC controller selection to optimise filter bank."

95.2. **Comments have been received from Power Grid**

95.2.1. **Power Grid** commented that the shunt capacitors, which are provided as a part of HVDC, will be switched automatically as per the settings in HVDC control so separate operational instructions need not be issued. Accordingly, Power Grid suggested adding "(excluding HVDC automatic RPC control)" to the sub-clause (ii) and adding one more sub clause (x) as below:

"(x) Inverter based reactive power support"

95.3. **Analysis and Decision**

95.3.1. The suggestions of Powergrid have been accepted. The draft regulation has been modified as 39 (7) in the 2023 Grid Code Regulations as follows

"(7) NLDC, RLDCs and SLDCs shall take appropriate measures to maintain the voltage within limits, inter-alia, using the following facilities, and the facility owner shall abide by the instructions of NLDC, RLDCs and SLDCs:
(i) shunt reactors,
(ii) shunt capacitors <u>(excluding HVDC automatic control),</u>
(iii) TCSC,
(iv) VSC based HVDC,
(v) synchronous/non-synchronous generator voltage <u>control including inverter based reactive power support,</u>
(vi) synchronous condenser,

(vii) static VAR compensators (SVC), STATCOM and other FACTS devices,
(viii) transformer tap change: generator transformer and inter-connecting transformer,
(ix) HVDC power order or HVDC controller selection to optimise filter bank."

96. Reactive Power Management (Regulation 39 (8))

96.1. **Commission's Proposal**

96.1.1. The Commission had proposed the following in Regulation 39 (8) of the Draft Regulations:

"(8) Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages and if required, other options such as tap staggering may be carried out in the network."

96.2. **Comments have been received from NTPC and Tata Power**

96.2.1. **NTPC** suggested that Generator transformers may be excluded from changing Taps periodically/ seasonally for voltage optimization.

96.2.2. **Tata Power** suggested not to do periodical or seasonal tap changing.

96.3. **Analysis and Decision**

96.3.1. With regard to suggestions of NTPC, "subject to technical feasibility and wherever necessary" has been inserted in the Regulation.

96.3.2. With regard to suggestions of Tata Power, it is clarified that such tap changing shall be carried out to optimise voltages, wherever feasible. The draft regulation has been modified as 39 (9) in the 2023 Grid Code Regulations as follows,

"(9) Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages, <u>subject to technical feasibility</u>, and where ever necessary, other options such as tap staggering may be carried out in the network."

97. Reactive Power Management (Regulation 39 (9))

97.1. **Commission's Proposal**

97.1.1. The Commission had proposed the following in Regulation 39 (9) of the Draft Regulations:

"(9) Hydro and gas generating units having capability shall operate in synchronous condenser mode operation as per instructions of RLDC or SLDC of the respective control area. Standalone synchronous condenser units shall operate as per instructions of RLDC or SLDC, as per respective control area."

97.2. **Comments have been received from NHPC**

97.2.1. **NHPC** suggested that the services for operation of Condenser Mode may be incentivized suitably so that the participation in the same is increased.

97.3. **Analysis and Decision**

97.3.1. Considering suggestions of NHPC, the procedure for compensation has been inserted. The draft regulation has been modified as 39 (10) in the 2023 Grid Code Regulations as follows,

"(10) Hydro and gas generating units having this capability shall operate in synchronous

condenser mode operation as per instructions of the RLDC or SLDC of the respective control area. Standalone synchronous condenser units shall operate as per the instructions of RLDC or SLDC, as per the respective control area. <u>The compensation for such synchronous condenser mode operation shall be included in the procedure to be submitted by NLDC and approved by the Commission.”</u>

98. Reactive Power Management (Regulation 39 (11))

98.1. **Commission’s Proposal**

98.1.1. The Commission had proposed the following in Regulation 39 (11) of the Draft Regulations:

“(11) If voltages are outside the limit as specified in clause (15) of Regulation 29 of these regulations and the means of voltage control set out in Clause (6) of this Regulation are exhausted, in that event SLDCs, RLDCs or NLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including opening of lines considering security of system.”

98.2. **Comments have been received from Power Grid**

98.2.1. **Power Grid** suggested replacing the word “opening” with “switching” in this clause.

Power Grid, during the public hearing of the Draft IEGC Grid Code, commented that transmission lines are switched ON/OFF frequently on voltage regulation, and none of the equipment like CT, CB, LA, etc., are type tested for electrical endurance like switching of transmission lines. Further it was commented that various failures of LA, CB, and GIS modules have been observed in the recent past due to frequent switching of lines during high voltage conditions. Power Grid suggested that switching of transmission lines for voltage control may be avoided.

98.3. **Analysis and Decision**

98.3.1. Suggestion of Powergrid to replace the word ‘opening’ with ‘Switching ON or OFF’ has been accepted. It is already provided that lines are switched as a last resort only by the system operator.

98.3.2. The draft regulation has been modified as 39 (12) in the 2023 Grid Code Regulations as follows,

“(12) If voltages are outside the limit as specified in clause (15) of Regulation 29 of these regulations and the means of voltage control set out in clause (7) of this Regulation are exhausted, SLDCs, RLDCs or NLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits <u>including switching ON or OFF</u> of lines considering the security of the system.”

99. Field Testing for Model Validation (Regulation 40)

99.1. **Commission’s Proposal**

99.1.1. The Commission had proposed the following in Regulation 40 of the Draft Regulations

“40. FIELD TESTING FOR MODEL VALIDATION”

99.2. **Comments have been received from POSOCO**

99.2.1. **POSOCO** suggested deleting the words “FOR MODEL VALIDATION”

99.3. **Analysis and Decision**

99.3.1. Considering the suggestions of POSOCO, the title under Regulation 40 of the 2023 Grid Code Regulations has been modified as follows:

"40. PERIODIC TESTING"

100. Field Testing for Model Validation (Regulation 40 (2))

100.1. **Commission's Proposal**

100.1.1. The Commission had proposed the following in Regulation 40 (2) of the Draft Regulations:

"(2) General provisions

(a) The owner of the power system element shall be responsible to carry out tests as specified in these regulations and for submission of reports to NLDC, RLDCs, CEA and CTU for all elements and to STUs and SLDCs for intra-State elements.

(b) All equipment owners shall submit a testing plan for the next year to the concerned RPC by 31st October for ensuring proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform the concerned RPC in advance.

(c) The tests shall be performed once in every five (5) years or whenever major retrofitting is done or if necessitated earlier due to any adverse performance observed during any grid event.

(d) The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports by the concerned RPC in consultation with NLDC, RLDC, CEA and CTU."

100.2. **Comments have been received from POSOCO**

100.2.1. **POSOCO** suggested the following modification in clause (c):

"(c) The tests shall be performed once every five (5) years or whenever major retrofitting is done. <u>In case if any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so advised by SLDC/RLDC/NLDC or RPC </u>~~or if necessitated earlier due to any adverse performance observed during any grid event~~."

POSOCO has also commented that the changes suggested by RPC need to be implemented which would ensure compliance and suggested deleting the words "by the concerned RPC"

100.3. **Analysis and Decision**

100.3.1. The suggestions of POSOCO have been accepted.

100.3.2. Regulation 40(2) of the 2023 Grid Code Regulations has been modified as follows:

"(2) General provisions

(a) The owner of the power system element shall be responsible for carrying out tests as specified in these regulations and for submitting reports to NLDC, RLDCs, CEA and CTU for all elements and to STUs and SLDCs for intra-State elements.

(b) All equipment owners shall submit a testing plan for the next year to the concerned RPC by 31st October to ensure proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform the concerned RPC in

advance.

(c) The tests shall be performed once every five (5) years or whenever major retrofitting is done. <u>If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so advised by SLDC or RLDC or NLDC or RPC, as the case may be.</u>

(d) The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports in consultation with NLDC, RLDC, CEA, RPC and CTU."

101. Field Testing for Model Validation (Regulation 40 (3))

101.1. **Commission's Proposal**

101.1.1. The Commission had proposed the following in Regulation 40 (3) of the Draft Regulations:

"(3) Testing requirements

The following tests shall be carried out on respective power system elements:

TABLE 9: TESTS REQUIRED FOR POWER SYSTEM ELEMENTS

Power System Elements	*Tests*	*Applicability*
Synchronous Generator	*(1) Real and Reactive Power Capability assessment.* *(2) Reactive Power Control Capability (As per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007) assessment.* *(3) Model Validation and verification test for the complete Generator and Excitation System model including PSS.* *(4) Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions.* *(5) Testing of Governor performance and Automatic Generation Control.*	*Individual Unit of rating 100MW and above for Coal/lignite, 50MW and above gas turbine and 25 MW and above for Hydro.*
Non synchronous Generator (Solar/Wind)	*(1) Real and Reactive Power Capability for Generator* *(2) Power Plant Controller Function Test* *(3) Frequency Response Test* *(4) Fault Ride through Test (sample testing of a unit in the generating stations).*	*Applicable as per CEA (Technical Standards for Connectivity) Regulations, 2007*
HVDC/FACTS Devices	*(1) Damping capability of HVDC/FACTS Controller* *(2) Frequency Controller Capability of HVDC Controller* *(3) Reactive Power Controller (RPC) Capability for HVDC/FACTS*	*To all ISTS HVDC as well as Intra-State HVDC/FACTS*

Power System Elements	Tests	Applicability
	(4) Validation of voltage dependent current order limiter (VDCOL) characteristic for ensuring proper validation of HVDC performance *(5) Filter bank adequacy assessment based on present grid condition.* *(6) Validation of response by FACTS devices as per settings.*	

101.2. **Comments have been received from SRPC, Greenko Group, Tata Power, Enel, National Solar Energy Federation of India, O2 Power, WIPPA, NTPC, Power Grid, Hitachi Energy, Sembcorp, IEEMA-Copper Alliance and POSOCO**

101.2.1. **SRPC** has suggested adding the following under Non synchronous Generator (Solar/ Wind) in Table 9:

"(4) Fault Ride through Test (sample testing of a unit in the generating stations *for each 50 MW block connected to Common Point of Coupling)*

(5) HVR Test (sample testing of a unit in the generating stations for each 50 MW block connected to Common Point of Coupling)"

101.2.2. **Greenko Group, Tata Power, Enel, National Solar Energy Federation of India, O2 Power,** and **WIPPA** requested clarification on whether these tests are mandatory to comply with existing projects or applicable for future projects?

101.2.3. **NTPC** commented that the Fault Ride through the Test of the unit (WTG/Solar Inverter) at the site (which is mostly remote for RE plants) requires specialised, costly equipment, and during testing, it also likely creates disturbances to the Grid it is connected. In the testing laboratory, simulators are available, which can be easily used for Fault Ride through testing, and permission from Grid is also available for such kind of testing facility. Therefore, the sample testing of the unit may also be allowed in any Internationally acceptable/NABL accredited Testing lab where such a facility is available. Hence NTPC has suggested replacing the words "in the generating stations" with "at factory before commissioning".

101.2.4. **Power Grid** commented that Field testing of Damping capability, Frequency controller, VDCOL and filter bank adequacy based in present grid condition is not possible at site. Accordingly, Power grid suggested deleting the Tests mentioned at SI. No. 1, 2, 4 and 5 under HVDC/FACTS Devices.

101.2.5. **Hitachi Energy** commented that Serial No 1, 2 and 4 - Damping and frequency controller and voltage dependent current order limiter (VDCOL) periodic tests at site is not possible to perform periodically and "Propose to be done by simulation in Replica/Test facility both during FST and whenever changed parameter or environment".

101.2.6. **Sembcorp** commented that the plants/units which do not have provision for AGC may be exempted from testing of Governor performance and Automatic Generation Control. Accordingly, suggested adding the following to sub clause (5) under Synchronous Generator, "where the units have AGC provision."

101.2.7. **POSOCO** in respect of Non synchronous Generator (Solar/Wind) commented that Field testing of Fault Ride through Test (sample testing of a unit in the generating stations) might be difficult to conduct. In the absence of adequate facilities/guidelines for field testing of RE based resources it would be more suitable to include other testing methods primarily based on model simulation. Further, the Active Power Set Point change test and Reactive Power (Voltage / Power Factor / Q) Set Point change test also have to be done in line with CEA Standards. Accordingly, POSOCO suggested adding the following under Non Synchronous Generator (Solar/Wind):

"(5) Active Power Set Point change test

(6) Reactive Power (Voltage / Power Factor / Q) Set Point change test

***Bulk Consumers like Electrolysers should have necessary provisions to ensure compliance of Fault ride through, frequency response and Reactive support etc."*

101.3. **Analysis and Decision**

101.3.1. With regard to suggestions to add additional tests for solar/wind generators by SRPC, it is observed that basic tests have been provided for in the 2023 Grid Code, and new tests may be added at appropriate times if the need arises. Active Set Point change test and reactive power set point change test as suggested by POSOCO, have been included.

101.3.2. It is further clarified that the testing requirements shall apply mandatorily to all entities which declared COD prior to the effective date of the 2023 Grid Code and post the effectiveness of the 2023 Grid Code.

101.3.3. Considering suggestions of NTPC Fault ride through test have been deleted under periodic testing and considering suggestions of Powergrid and Hitachi, tests for HVDC have been modified.

101.3.4. Regulation 40 (3) of the 2023 Grid Code Regulations has been modified as follows:

"(3) Testing requirements

The following tests shall be carried out on the respective power system elements:

TABLE 9: TESTS REQUIRED FOR POWER SYSTEM ELEMENTS

Power System Elements	*Tests*	*Applicability*
Synchronous Generator	*(1) Real and Reactive Power Capability assessment.* *(2) Assessment of Reactive Power Control Capability as per CEA Technical Standards for Connectivity* *(3) Model Validation and verification test for the complete Generator and Excitation System model including PSS.* *(4) Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions.* *101.3.5. (5)Testing of Govern performance and* Automatic *Generati*	*Individual Unit of rating 100MW and above for Coal/lignite, 50MW and above gas turbine and 25 MW and above for Hydro.*

Power System Elements	Tests	Applicability
	Control.	
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Active Power Set Point change test (5) Reactive Power (Voltage/Power Factor/Q) Set Point Change Test	Applicable as per CEA Technical Standards for Connectivity
HVDC/FACTS Devices	(1) Reactive Power Controller (RPC) Capability for HVDC/FACTS (2) Filter bank adequacy assessment based on present grid condition, in consultation with NLDC (3) Validation of response by FACTS devices as per settings.	To all ISTS HVDC as well as Intra-State HVDC/FACTS as applicable

CHAPTER-7 - SCHEDULING AND DESPATCH CODE

1. Control Area Jurisdiction of Load Despatch Centre (Regulation 43 (3))

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation 43 (3) of the Draft Regulations:

"(3) The SLDCs shall be responsible for scheduling and despatch of electricity, monitoring of real time grid operations and management of the reserves including energy storage system and demand response within its State control area, supervision and control over the intra-State transmission system, processing of interface energy meter data and coordinating the accounting and settlement of State pool account, as may be specified by the appropriate State Commission."

1.2. **Comments have been received from Tata Power.**

1.2.1. **Tata Power** has suggested that the word "optimum scheduling" may be used instead of "scheduling"

1.3. **Analysis and Decision**

1.3.1. The suggestion of Tata Power has been accepted and the regulation have been modified as follows:

"(3) The SLDCs shall be responsible for <u>optimum</u> scheduling and despatch of electricity, monitoring of real time grid operations and management of the reserves including energy storage systems and demand response within its State control area, supervision and control over the intra-State transmission system, processing of interface energy meter data and coordinating the accounting and the settlement of State pool account, as may be specified by the appropriate State Commission."

2. Control Area Jurisdiction of Load Despatch Centre (Regulation 43 (4) and (5))

2.1. **Commission's Proposal**

2.1.1. The Commission had proposed the following in Regulation 43 (5) of the Draft Regulations:

"43(4) The entities connected only to inter-State transmission system shall be under control area jurisdiction of RLDCs for scheduling and despatch of electricity for such entities.

43(5) Entities connected to both inter-State transmission system and intra-State transmission system shall be under control area jurisdiction of RLDC, if more than 50% of quantum of connectivity is with ISTS, and if more than 50% of the quantum of connectivity is with intra-State transmission system, then it shall be under control area jurisdiction of SLDC."

2.2. **Comments have been received from PTC, AP Transco, SJVNL, NTPC, Sterlie, Balco, SRPC, PCKL, KPTCL, Dhariwal, GRIDCO, SLDC Odisha, HPSLDC and POSOCO.**

2.2.1. **PTC India** has commented that equal connectivity with inter-state and intra-state systems should be clearly addressed.

2.2.2. **AP TRANSCO** has requested for clarification with regard to entities like NTPC Simhadri-1(ISGS) connected to the AP intra state transmission system and supplying power to two or more states. AP Transco also commented that there is ambiguity about whether scheduling responsibility is with SLDC or RLDC.

2.2.3. **SJVNL** has suggested that if the Project location is in One State and the Connectivity Granted in the Intra- State Network of another state and the PPA has not been tied up, then the Control Area Jurisdiction of Load Despatch may be specified i.e., which State load despatch centre would give the approval for the Charging new elements into the Grid/ Synchronization / COD / Schedule, etc.

2.2.4. **NTPC** has suggested that the clauses 6.4.2 and 6.4.3 of the existing IEGC may be retained.

2.2.5. **Sterlite** & **BALCO** has suggested that since in GNA Regulation Bulk Consumers/Distribution Licensee will have GNA and not connectivity so inclusion of GNA will remove ambiguity for Bulk Consumer/Distribution Licensee. The IEGC has not stipulated the control area jurisdiction in case of 50% quantum of connectivity with inter-State transmission system and other 50% with intra-State transmission system.

2.2.6. **SRPC, PCKL, KPTCL, Dhariwal,** and **GRIDCO** have suggested that Inter and Intra state systems shall be under the control area jurisdiction of RLDC if 50% or more than 50% of the quantum is with ISTS.

PCKL has also suggested that if the quantum of connectivity is equally connected (50% each) to both the Inter-state transmission system and the Intrastate transmission system, then RLDC and SLDC shall schedule the Power in coordination.

2.2.7. **POSOCO** has suggested that these provisions may be made applicable prospectively.

2.2.8. **SRPC** has suggested that CGS only connected to the intra state network and having share only to the home state may be scheduled by SLDCs, and in case of mutual consensus at RPC level, an entity may be scheduled by RLDC or SLDC as the case may be. SRPC has suggested that scheduling of CGS having a share in more than one state should be with RLDC, as for accounting purposes, all data should come through RPCs from respective RLDCs, and if control area jurisdiction is shifted to SLDCs, there may be issues in the computation of PAF, RRAS, SCED optimisation etc.

2.2.9. **HPSLDC** has suggested that if an ISGS is connected to a host State intra-state transmission system and the different States have power shares in that ISGS, then that ISGS shall come under the jurisdiction of the host State SLDC if the host State has a power share of more than 50% otherwise that ISGS shall come under the jurisdiction of respective RLDC.

2.2.10. **SLDC Odisha** has suggested that the earlier provision regarding control area jurisdiction for scheduling and dispatch, which is based on % share, may be retained.

2.3. Analysis and Decision

2.3.1. Considering the suggestions of PTC, Sterlite, BALCO, PCKL regarding the equal quantum of connectivity with ISTS and STU, it is provided that the control area jurisdiction in case where an entity has equal connectivity to both ISTS and InSTS, that entity shall be under the control area jurisdiction of the respective RLDC

2.3.2. With respect to the query of AP Transco for Simhadri which is an existing generating station, the scheduling jurisdiction as existing prior to effectiveness of the 2023

Grid Code has been retained. It is also clarified that power supply to more than one state is not the deciding criterion as per the 2023 Grid Code, but the jurisdiction would be decided based on quantum of connectivity granted with ISTS and STU.

2.3.3. Regarding the suggestion from SJVNL, the Commission provides clarifies that the approval will be provided by the SLDC of the state to which the project is connected for evacuation.

2.3.4. With respect to the suggestion provided by NTPC, SRPC, HPSLDC, and SLDC Odisha to keep scheduling jurisdiction based on share of power, it is observed that under the GNA Regulations, flexibility has been provided to the drawee entities to draw power under any contract within the GNA quantum. Similarly, generating stations are also selling URS power under power exchange. In such a dynamic scenario where the share of power may change dynamically, the concept of control area jurisdiction based on the share of power was proposed to be done away in the Draft Regulations. A CGS, if connected only to the intra-State system should be under the control area of SLDC since the connected intra-State transmission system is under the control of SLDC. Similarly, the CGS connected only to ISTS should be under RLDC jurisdiction since all connected transmission lines are under ISTS. The Commission has already provided a detailed rationale in the Explanatory Memorandum.

2.3.5. With respect to the suggestion of Sterlite and BALCO, the Commission clarifies that if GNA is provided to a bulk consumer or a distribution licensee under Regulation 17.1(iii) of the GNA Regulations, Connectivity is inbuilt in such GNA and shall be construed accordingly for the purpose of scheduling jurisdiction.

2.3.6. The suggestion of POSOCO has been accepted. The entities which have already declared COD as on the date of coming into force of these regulations shall continue to remain under the control area of the SLDC or the RLDC, as the case may be, as existing before the date of coming into force of these regulations.

2.3.7. With regard to suggestions of SRPC to keep a provision for jurisdiction based on mutual consensus, Clause (10) has been inserted as follows:

> *"Notwithstanding anything contained in clauses (1) to (8) of this Regulation, the Commission may, on its own motion or on the application made by a grid connected entity, grant approval for a change in the control area jurisdiction of such an entity."*

2.3.8. The regulation has been modified as follows:

"

(4) The entities connected <u>exclusively</u> to the inter-State transmission system shall be under the control area jurisdiction of RLDCs for scheduling and despatch of electricity for such entities.

(5) <u>The entities connected exclusively to the intra-State transmission systems shall be under the control area jurisdiction of SLDCs for scheduling and despatch of electricity</u>.

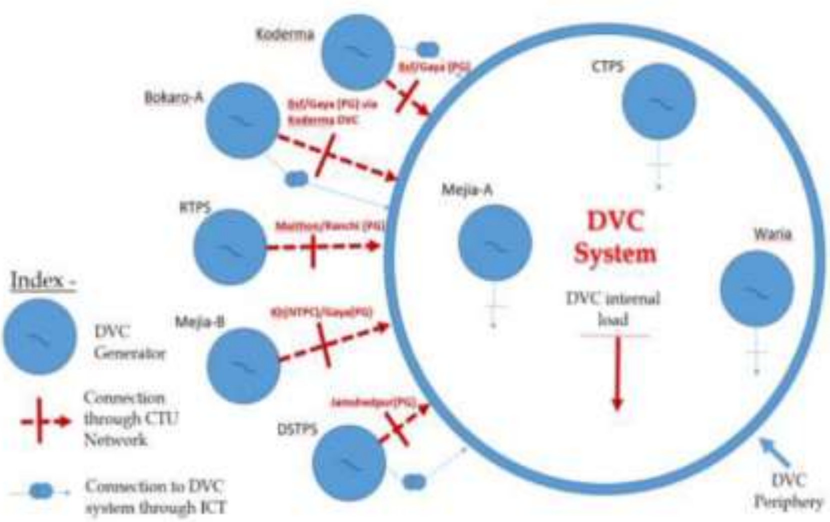
(6) Entities connected to both inter-State transmission systems and intra-State transmission systems shall be under the control area jurisdiction of RLDC, if more than or equal to 50% of the quantum of connectivity is with ISTS, and if more than 50% of the

quantum of connectivity is with intra-State transmission system, it shall be under the control area jurisdiction of SLDC.”

2.3.9. Keeping in view the suggestions of stakeholders, Clause (8) has been inserted, saving the scheduling jurisdiction of entities already declared COD as on the effectiveness of the 2023 Grid Code as follows:

> *“(8) Unless otherwise decided by the Commission, the entities that have already declared COD as on the date of coming into force of these regulations, shall continue to remain under the control area of the SLDC or the RLDC, as the case may be, as existing before the date of coming into force of these regulations:*
>
> *Provided that the control area jurisdiction of generating stations of DVC that have already achieved COD as on coming into force of these regulations shall be as per Clause (9) of this regulation.”*

2.3.10. It is also clarified that under the Draft Regulations, the scheduling jurisdiction of all entities, including DVC, was proposed to be decided based on Clauses (4) to (6) of the Draft Regulations, i.e. based on Connectivity to STU and/or ISTS. However, keeping in view, the suggestions of POSOCO to retain the scheduling jurisdiction of entities declared COD as on date of effectiveness of the 2023 Grid Code, Clause (8) has been inserted. However, for DVC owned generating stations, the scheduling jurisdiction has been retained in the 2023 Grid Code as proposed in the Draft Regulations, including that for the generating stations that have been declared COD as on the effectiveness of the 2023 Grid Code. The reasons for same is that a few generating stations of DVC are connected exclusively to ISTS and a few generating stations are connected to ISTS and intra-State system (with less than 50% connectivity with the intra-State system), however, scheduling is being done by DVC SLDC, which is not as per provisions of the 2010 Grid Code. This was noted and considered while finalising GNA Quantum for DVC under the GNA Regulations. While proposing the Draft GNA Regulation in 2021, the following was provided in the Explanatory Memorandum:



(i) It is observed that although DVC as a control area have been considering injection for the above said identified generating stations as its embedded generating stations, but the

transmission lines connecting such stations to DVC owned system is not within DVC control area. This needs to be considered while considering actual ISTS drawal for DVC.
(j) Accordingly, it is proposed that DVC as a State control area shall be granted deemed GNA as per the formula proposed under Regulation 18.1(a) of the 2021 Draft GNA Regulations with a condition that ISTS drawl shall be has been considered after excluding injection from those generating stations that are connected to ISTS (Mejia Thermal Power Station #7 & #8, Durgapur Steel Thermal Power Station #1 & #2, Koderma Thermal Power Station #1 & #2, Bokaro Thermal Power Station-A #1, Raghunathpur Thermal Power Station #1 & #2).
(k) Generating stations of DVC that are connected to ISTS (Mejia Thermal Power Station #7 & #8, Durgapur Steel Thermal Power Station #1 & #2, Koderma Thermal Power Station #1 & #2, Bokaro Thermal Power Station-A #1, Raghunathpur Thermal Power Station #1 & #2) shall be treated like any other ISGS (inter-State generating station) which shall need to have a GNA at its injection point for its power to get scheduled. The Connectivity or LTA already obtained by such stations shall be treated in terms of Regulation 37 of the 2021 draft GNA Regulations."

As per the above, injections from identified generating stations *(Mejia Thermal Power Station #7 & #8, Durgapur Steel Thermal Power Station #1 & #2, Koderma Thermal Power Station #1 & #2, Bokaro Thermal Power Station-A #1, Raghunathpur Thermal Power Station #1 & #2)* owned by DVC and which were scheduled by DVC, were considered as if they are being scheduled by RLDC and accordingly GNA was considered for DVC as a drawing entity. The identified generating stations of DVC were treated like any other ISGS which shall need to have a GNA at its injection point for its power to get scheduled.

Accordingly, a new Clause (9) has been inserted in the 2023 Grid Code as follows:

"(9) Control Area jurisdiction of the generating station of DVC and other entities connected to the DVC system

(i) The control area of the generating stations of DVC which are connected to the transmission lines of inter-State transmission licensees including those owned and operated by DVC which are included in monthly transmission charges under the Sharing Regulations shall be under control area jurisdiction of RLDC;

(ii) The control area of the generating stations which are exclusively connected to the transmission system owned and controlled by DVC but are not included in monthly transmission charges under Sharing Regulations shall be under control area jurisdiction of DVC LDC;

(iii) The control area of the generating stations which are connected to transmission system covered under both sub-clause (i) and (ii), shall be within the jurisdiction of RLDC if more than or equal to 50% of the quantum of connectivity is with transmission system covered under sub-clause (i) of this clause and in other cases will be under the control area of jurisdiction of DVC LDC.

(iv) The control area of entities other than generating stations connected to the DVC system shall be governed in terms of sub-clauses (i) to (iii) of this clause."

3. Responsibilities of Load Despatch Centres (Regulation 44 (1) (a))

3.1. Commission's Proposal

3.1.1. The Commission had proposed the following in Regulation 44 (1) (a) of the Draft

Regulations:

“(1) The Regional Load Despatch Centre, in discharge of its functions under the Act, shall be responsible for the following, within its regional control area:

a) Forecasting of demand based on the inputs from SLDCs (under clause (2) of Regulation 31 of these regulations) and other regional entities for each time block on day-ahead and intraday basis”

3.2. **Comments have been received from POSOCO.**

3.2.1. POSOCO has suggested that the word “intraday” may be replaced with “on week ahead rolling” in the clause.

3.3. **Analysis and Decision**

3.3.1. The suggestion to include week ahead instead of intraday is not accepted. The timeline for submission of demand estimate data by SLDCs under Regulation 31(2)(h) of the 2023 Grid Code regulations already provides for weekly demand estimation.

3.3.2. The provision as proposed in the Draft Regulations has been retained.

4. Responsibilities of Load Despatch Centres (Regulation 44 (1) (c))

4.1. **Commission’s Proposal**

4.1.1. The Commission had proposed the following in Regulation 44 (1) (c) of the Draft Regulations:

“(c) Scheduling of electricity within the region which includes:
(i) Injection and drawal schedule for regional entities, cross-border entities, in accordance with the contracts;
(ii) Incorporation of schedules under collective transactions for regional entities;
(iii) optimisation of scheduling inter alia through Security Constrained Economic Despatch (SCED);”

4.2. **Comments have been received from PXIL, Prayas, MPPMCL, and POSOCO.**

4.2.1. PXIL has suggested that post matching of Orders received in different bilateral Contracts, when both Buyer and Seller are located in the same State, then, to avoid applicability of inter-state transmission charges and losses to the transaction, the application needs to be submitted to SLDC of the State for scheduling delivery of power.

4.2.2. **Prayas** has suggested that SCED and SCUC are relatively new concepts for Indian grid operators and generators, so SCUC and SCED need not be made mandatory at this stage in the IEGC. The process of rolling these out can be decided based on the results from the pilot implementations of the Market Based Economic Dispatch.

4.2.3. **MPPMCL** has suggested that some of the IPPs with partial contracted capacity with MPPMCL, have given net injection schedule exceeding the declared capacity on the portal of RLDC resulting into undue benefits to IPPs at the cost of Discoms, regulatory provisions need to be made assigning Load Despatch Centres responsibility of validating net injection schedule with declared capacity.

4.2.4. **POSOCO** has suggested that for scheduling of electricity within the region, Injection and drawal schedule for regional entities, cross-border entities, in accordance with the contracts or share allocation by central govt. for CGS shall be submitted.

POSOCO has also suggested including schedules under Ancillary services regulations and schedules under new market products as per the CERC orders and amendments.

4.3. **Analysis and Decision**

4.3.1. With regard to the suggestion of PXIL, it is clarified that if a bilateral transaction is between two entities within the State Control area, the same is governed as per SERC Regulations since ISTS is not involved.

4.3.2. With respect to the suggestion of Prayas, it is clarified that SCED has been operational for a duration of 3 years and has led to overall optimisation. Further, MBED is not related to SCUC as SCUC was introduced for the purpose of maintaining reserves.

4.3.3. Regarding MPPMCL suggestion, it is clarified that RLDC must ensure that the injection schedule does not exceed the declared capacity. The regulations already contain sufficient provisions to restrict the schedules up to the declared capacity. Under no circumstances, scheduled net injection exceed the declared capacity of the generating station. To prevent any such discrepancies, RLDCs are directed to enable a necessary checkbox in their web-based scheduling software to enforce compliance with the regulatory provisions regarding schedule limitations.

4.3.4. As regards the suggestion of POSOCO to include share allocation by the Central Government for CGS, it is clarified that such share allocations are also a form of contract and are included therein. Therefore, they are implicitly covered under the contracts specified in this regulation. The suggestions of POSOCO to include schedules under Ancillary services regulations have been accepted. The incorporation of schedules under new market products may be decided as and when deemed necessary.

4.3.5. Regulation 44 (1) (c) of the 2023 Grid Code Regulations has been modified as follows:

"(c) Scheduling of electricity within the region which includes:

(i) Injection and drawal schedules for regional entities, cross-border entities, in accordance with the contracts;

(ii) Incorporation of schedules for regional entities under collective transactions;

(iii) <u>Incorporation of schedules under the Ancillary Services Regulations</u>.

(iv) optimisation of scheduling inter-alia through Security Constrained Economic Despatch (SCED);"

5. Responsibilities of Load Despatch Centres (Regulation 44 (1) (e))

5.1. **Commission's Proposal**

5.1.1. The Commission had proposed the following in Regulation 44 (1) (e) of the Draft Regulations:

"(e) Assessment of transmission capacity for inter-State transmission system for secure operation of the grid including but not limited to:

(i) Assessment of TTC and ATC for inter-regional, intra-regional and inter-State levels for its region and submit to NLDC.

(ii) Assessment of TTC and ATC for import or export of electricity for a State in coordination with concerned SLDC and submit to NLDC."

5.2. **Comments have been received from POSOCO and SRPC.**

5.2.1. POSOCO has suggested that the word "capacity" may be substituted with the word "capability".

5.2.2. **SRPC** has suggested that the responsibility of TTC/ATC of the state lies with the state only, and only assessment or vetting can be done by NLDC/RLDC.

5.3. **Analysis and Decision**

5.3.1. Suggestions of POSOCO to replace the word ‘capacity’ with ‘capability’ have been accepted.

5.3.2. Suggestions of SRPC are not accepted since the grid is to be operated in an integrated manner and for which ATC/TTC is required to be assessed by NLDC/RLDC. The assessment of TTC and ATC for importing or exporting electricity for a State should be conducted in coordination with the concerned SLDC. The responsibilities of the State in this regard have been elaborated in the subsequent clause of this regulation, wherein the SLDC has been assigned the responsibility of declaring the TTC and ATC as per Regulation 44(3)(f) of these regulations.

5.3.3. The Commission observes that the assessment of TTC and ATC is subject to change based on grid conditions, changes in the network topology, transmission line/ generator outages, and other contingencies. Therefore, the Commission is of the view that the assessment of TTC and ATC should be continuously assessed, and revised as necessary in response to changes in grid conditions due to addition of any new element or contingency. The revised TTC/ATC should be posted at least 3 months in advance.

5.3.4. Regulations have been modified as follows:

“(e) Assessment of transmission capability for inter-State transmission system for secure operation of the grid including but not limited to:
(i) Assessment of TTC and ATC for inter-regional, intra-regional and inter-State levels for its region and submit it to the NLDC.
(ii) Assessment of TTC and ATC for import or export of electricity for a State in coordination with the concerned SLDC and submit to NLDC.
(iii) Assessment of TTC and ATC shall be done on a continuous basis at least three (3) months in advance and revised based on contingencies from time to time.”

6. Responsibilities of Load Despatch Centres (Regulation 44 (2) (c))

6.1. **Commission’s Proposal**

6.1.1. The Commission had proposed the following in Regulation 44 (2) (c) of the Draft Regulations:

“(2) The National Load Despatch Centre, in discharge of its functions under the Act, shall be responsible for the following:
(c) Coordination and scheduling of trans-national exchange of power;”

6.2. **Comments have been received from POSOCO**

6.2.1. POSOCO has suggested that the word “trans-national” may be substituted with the word “cross border”.

6.3. **Analysis and Decision**

6.3.1. The suggestion of POSOCO has been considered and the clause has been modified accordingly,

“(c) Coordination and scheduling of cross-border exchange of power;”

7. Responsibilities of Load Despatch Centres (Regulation 44 (2) (g))

7.1. **Commission's Proposal**

7.1.1. The Commission had proposed the following in Regulation 44 (2) (g) of the Draft Regulations:

"(g) Furnishing availability of transmission corridors to the Power Exchange(s) for day ahead and real time collective transactions and in case of congestion, allocating available transmission corridors among Power Exchange(s) in the ratio of initial unconstrained market clearing volume in the respective Power Exchange(s)."

7.2. **Comments have been received from PXIL, SRPC.**

7.2.1. PXIL has suggested adding the following at the end of the clause, "or as prescribed by the Commission from time to time".

7.2.2. **SRPC** has suggested that in case of congestion, allocating available transmission corridors among Power Exchange(s) shall be as per the CERC approved procedure.

SRPC has also suggested that NLDC be responsible for reviewing, defining and deleting Bid Areas for Power Exchanges and securing the grid's operation by performing functions in accordance with Grid Code Regulations and Ancillary Services Regulations.

7.3. **Analysis and Decision**

7.3.1. Suggestions of PXIL and SRPC have been accepted and accordingly "*or as specified by the Commission from time to time*" have been inserted in the Clause.

7.3.2. With regard to suggestions of SRPC to add 'bid areas', it is clarified that the same may be considered separately after due stakeholder consultations.

7.3.3. Regulation 44 (2) (g) of the 2023 Grid Code Regulations has been modified as follows:

"(g) Furnishing availability of transmission corridors to the Power Exchange(s) for day ahead and real time collective transactions and, in case of congestion, allocating available transmission corridors among the Power Exchange(s) in the ratio of initial unconstrained market clearing volume in the respective Power Exchange(s) <u>or as specified by the Commission from time to time</u>."

8. Responsibilities of Load Despatch Centres (Regulation 44 (3) (e))

8.1. **Commission's Proposal**

8.1.1. The Commission had proposed the following in Regulation 44 (3) (e) of the Draft Regulations:

"(e) Maintaining and despatching reserves;"

8.2. **Comments have been received from SRPC.**

8.2.1. SRPC has suggested that maintaining and despatching reserves should be in accordance with SERC notified Ancillary Services Regulations and also suggested that till the Ancillary Services Regulations are notified by SERCs, maintaining and despatching reserves should be in accordance with the Gird Code regulations.

8.3. **Analysis and Decision**

8.3.1. The Commission has noted the suggestions of the stakeholders.

8.3.2. The Commission is of the opinion that adequate reserves need to be maintained at both regional and state control areas to make sure that the responsibility of providing reserves is shared by all control areas. The Commission has framed the Regulations for

Ancillary Services at the inter-State level and the complementary framework may be implemented by the State Electricity Regulatory Commissions for respective State Control Areas.

8.3.3. The provision as proposed in the Draft Regulations has been retained.

9. Responsibilities of Load Despatch Centres (Regulation 44 (3) (f))

9.1. Commission's Proposal

9.1.1. The Commission had proposed the following in Regulation 44 (3) (f) of the Draft Regulations:

"(f) Declaring Total Transfer Capacity and Available Transfer Capacity in respect of import and export of electricity of its control area with inter-State transmission system in coordination with the Central Transmission Utility and revising the same from time to time based on grid conditions"

9.2. Comments have been received from SRPC, and POSOCO.

9.2.1. SRPC has suggested that SLDC needs to coordinate with RLDC and STU along with Central Transmission Utility while declaring TTC and ATC.

9.2.2. **POSOCO** has suggested that the words "Total Transfer capacity with Total Transfer capability" may be removed and suggested that ATC/TTC may be assessed periodically (monthly/quarterly) and shall be posted on website (3 months ahead or one year ahead).

9.3. Analysis and Decision

9.3.1. Suggestions of SRPC that SLDC needs to interact with RLDC and STU for correct assessment of TTC/ATC, is accepted. Suggestions of POSOCO to declare ATC/TTC three months in advance are accepted.

9.3.2. Regulation 44 (3) (f) of the 2023 Grid Code Regulations has been modified as follows:

"(f) Declaring Total Transfer Capability and Available Transfer Capability in respect of import and export of electricity of its control area with inter-State transmission systems in coordination with the Central Transmission Utility<u>, State Transmission Utility, and concerned RLDC</u> and revising the same from time to time based on grid conditions. Assessment of TTC and ATC <u>shall be done on a continuous basis at least three (3) months in advance</u> and revised based on contingencies from time to time."

10. Responsibilities of Load Despatch Centres (Regulation 44 (4))

10.1. Commission's Proposal

10.1.1. The Commission had proposed the following in Regulation 44 (4) of the Draft Regulations:

"(4) Damodar Valley Corporation and Settlement Nodal Agency shall carry out the responsibilities in their respective control area, in accordance with clause (2) of this Regulation, for stable, smooth and secure operation of the integrated grid."

10.2. Comments have been received from DVC and POSOCO

10.2.1. DVC has suggested that the proposed provision under Sl. No.1, SLDC, DVC will perform the functions of SLDC in the control area of DVC.

10.2.2. **POSOCO** has suggested that the Control Area jurisdiction of BBMB and SSP should also be mentioned.

10.3. **Analysis and Decision**

10.3.1. The Commission has noted the suggestions of the stakeholders.

10.3.2. As per Regulation 2(2) of these regulations, the DVC Load Despatch Centre (LDC) shall perform the functions of a State Load Despatch Centre (SLDC) for the control area of DVC.

10.3.3. As regards the suggestion of POSOCO, the provisions related to Bhakra Beas Management Board and Narmada Control Authority have been incorporated in Clause (5) and Clause (6) of this regulation.

10.3.4. Regulation 44 (4) of the 2023 Grid Code Regulations has been modified as follows:

"(4) Damodar Valley Corporation shall carry out the responsibilities in their respective control area, in accordance with clause 3 of this Regulation, for the stable, smooth, and secure operation of the integrated grid.

(5) Bhakra Beas Management Board and Narmada Control Authority shall coordinate with the concerned RLDC for scheduling and despatch of their generating stations.
(6) Settlement Nodal Agency shall coordinate with the concerned RLDC and NLDC for scheduling, despatch, and settlement for its control area"

11. General Provisions (Regulation 45 (2))

11.1. **Commission's Proposal**

11.1.1. The Commission had proposed the following in Regulation 45 (2) of the Draft Regulations:

"(2) The regional entity generating stations must be capable of receiving the load setpoint signals from the RLDCs/NLDC as per CEA Technical Standards for Connectivity."

11.2. **Comments have been received from SRPC and OTPC.**

11.2.1. SRPC has suggested that the regional entity generating stations and entities participating in Ancillary Services must be capable of receiving the load set point signals from the RLDCs/NLDC as per the CEA Technical Standards for Connectivity.

11.2.2. **OTPC** has suggested not to consider OTPC Palatana station in SRAS providers list due to operational issues and as such allow exemption from setting up the bi-directional communication system with RLDC.

11.3. **Analysis and Decision**

11.3.1. Suggestions of SRPC have been accepted that entities participating in Ancillary services must be capable of receiving signals from RLDCs/NLDC in terms of the Ancillary Service Regulations.

11.3.2. With regard to suggestions of OTPC to exempt OTPC, it is clarified that the aforesaid requirement is as per the CEA Technical Standards. In case of any technical difficulty, exemption needs to be sought through appropriate application with details of such difficulty.

11.3.3. Regulation 45 (2) of the 2023 Grid Code Regulations has been modified as follows:

"(2) The regional entity generating stations <u>and the entities participating in Ancillary Services</u> must be capable of receiving the load set point signals from the RLDCs or the NLDC as per CEA Technical Standards for Connectivity, <u>or in terms of Ancillary Service Regulations, as applicable.</u>"

12. General Provisions (Regulation 45 (4) (a) & (b))

12.1. **Commission's Proposal**

12.1.1. The Commission had proposed the following in Regulation 45 (4) (a) & (b) of the Draft Regulations:

"(4) Entitlement of a buyer and beneficiary:
(a)In cases of allocation of power from central generating station by the Central Government, each beneficiary shall be entitled for MW despatch out of declared capacity of such generating station, in proportion to its share allocation.
(b) For all other cases not covered under Clause (a), the buyer shall be entitled for MW despatch out of declared capacity of regional entity generating station as per its contracts"

12.2. **Comments have been received from Statkraft**

12.2.1. Statkraft has requested clarification that suppose a 1000 MW plant has 3 buyers having PPAs of (i) Buyer-1: 300 MW (ii) Buyer -2: 200 MW & (iii) Buyer-3: 500 MW. The tariff for all three buyers is different. Further, the plant has declared availability of 500 MW. Will each Buyer get scheduled in proportion to their contracted capacity or will the generator have the flexibility to schedule more power under PPA, which has a higher tariff?

12.3. **Analysis and Decision**

12.3.1. With regard to clarification sought, it is clarified that the entitlement of the beneficiary shall be specified by RLDC only in case of the Central generating stations where allocation of power is carried out by Central Government. For all other cases such as the one stated by Statkraft, the scheduling shall be as per contracts entered into between buyer and seller.

12.3.2. The provision as proposed in the Draft Regulations has been retained.

13. General Provisions (Regulation 45 (5) (a))

13.1. **Commission's Proposal**

13.1.1. The Commission had proposed the following in Regulation 45 (5) (a) of the Draft Regulations:

"(a) The following documents shall be submitted to the respective RLDC before commencement of scheduling of transactions under GNA or T-GNA, as the case may be:
(i)Grant of GNA with effective date, by the sellers and the buyers;
(ii) Grant of T-GNA with effective date, by the buyers;
(iii) Declaration by the sellers and the buyers about existence of valid contracts for the transactions.
(iv) Copies of the valid contracts by the sellers and the buyers, for transactions other than collective transactions."

13.2. **Comments have been received from Statkraft, Jindal India TPL, Torrent Power, Sembcorp, and NVVN.**

13.2.1. Statkraft has suggested that a grant of GNA and/or Connectivity, with an effective date, by the sellers and the buyers shall be submitted to the respective RLDC.

13.2.2. **Jindal India TPL** has suggested that the contracts are unique to sellers and buyers, and LTA/MTOA contract copies are being already submitted in RLDC. But for T-GNA contracts, generators and buyers regularly enter into new contracts so it will be difficult to share such copies. The same may be clarified.

Jindal India TPL has suggested that copies of valid long/medium-term power sale contracts may be submitted to the RLDC.

13.2.3. **Torrent Power** has suggested that the requirements under provisions (iii) and (iv) may be deleted.

13.2.4. **Sembcorp** has commented that the GNA is yet to become effective and the generator is ready partly or fully to schedule its power. Sembcorp asked, which documents the generator would require to submit to RLDC for commencement of scheduling as per 2nd Provision of Clause 22.4 of GNA Regulations?

13.2.5. **NVVN** has commented that to fulfil the requirement of submission of a valid contract(s) document to the respective RLDC before the commencement of scheduling under GNA/T-GNA, LOA issued by buyers to the trading licensee/authorisation letter issued by the generator to the trading licensee should be accepted as valid proof of contract for scheduling power when the trading licensee is applying for a corridor to RLDC.

13.3. **Analysis and Decision**

13.3.1. Suggestions of Statkraft to submit "Connectivity" with an effective date have been accepted.

13.3.2. With regard to suggestions of JPL, it is clarified that all contracts are required to be submitted to RLDC, under which scheduling is required, since RLDC shall schedule power only as per contracts under the Act.

13.3.3. With regard to suggestions of Torrent Power, it is clarified that a declaration for the valid contract has been provided for in the Regulations to ensure that a seller is not selling the same power twice. Such declaration may be given in a standard format at the portal of RLDC/NLDC. Further, keeping in view suggestions of Torrent Power, it is observed that a copy of the contract once furnished need not be furnished again on a daily basis and, the sub-clause (c) as follows have been inserted in the Regulation:

> *"(c) The copy of contracts once submitted by sellers and buyers need not be submitted again before every scheduling request and the copy of the contract can be linked with a unique ID by RLDC for reference before scheduling request:*
>
> *Provided that in case of any change in terms of the contract or termination of contract, the seller as well as the buyer shall inform the same, along with a copy of the modified contract, as applicable, within a day, to the respective RLDC.*

13.3.4. With regard to suggestions of Sembcorp, it is clarified that when GNA is yet to become effective for a generating station, any power that is scheduled for such generating station is considered as under T-GNA (for the purpose of scheduling and curtailment priority). Regulation 22.4 of the GNA Regulations provides as follows:

> *"..Provided also that where such GNA is yet to become effective, such entity shall be eligible to get its power scheduled partly or fully of the quantum of Connectivity sought for, subject to availability of transmission system by*

treating such access as deemed T-GNA, and shall not be required to pay T-GNA charges."

Further, to clarify the documents to be furnished by such generating station, sub-clause(iii) has been inserted as "*Request for consideration under Regulation 22.4 of the GNA Regulations, if applicable.".* In addition to this, documents as per sub-clauses (i), (v), and (vi) of Clause 5(a) of Regulation 45 shall be required to be furnished.

13.3.5. With regard to suggestions of NVVN to consider LOA/ authorisation letter, it is clarified that the document that qualifies as a contract under the Act can only be considered for scheduling.

13.3.6. Regulation 45 (5) (a) of the 2023 Grid Code Regulations has been modified as follows:

"(5) Requirement for Commencement of Scheduling:
(a) The following documents shall be submitted to the respective RLDC by the seller or the buyer, as the case may be, before commencement of the scheduling of transactions under GNA or T-GNA, as the case may be:
(i) <u>Document in support of the grant</u> of GNA or Connectivity, by the sellers and the buyers, as applicable;
(ii) <u>Document in support of the effective date of GNA by the sellers and the buyers</u>
<u>(iii) Request for consideration under Regulation 22.4 of the GNA Regulations, if applicable.</u>
(iv) Grant of T-GNA with an effective date, by the buyers;
(v) Declaration by the sellers and the buyers about the existence of valid contracts for the transactions.
(vi) Copies of the valid contracts signed by the sellers and the buyers, for transactions other than collective transactions."

14. General Provisions (Regulation 45 (5) (b))

14.1. **Commission's Proposal**

14.1.1. The Commission had proposed the following in Regulation 45 (5) (b) of the Draft Regulations*:*

"(b) In case of allocation of power from the central generating stations by the Central Government, the concerned RLDC shall obtain the share allocation of each beneficiary issued by RPC"

14.2. **Comments have been received from POSOCO**

14.2.1. **POSOCO** has suggested that scheduling by RLDC shall be commenced not before 3 days of issuance of share allocation.

14.3. **Analysis and Decision**

14.3.1. It is observed that the allocation of power from the Central Generating Station is done by the Ministry of Power, Government of India and the corresponding allocation is included in the allocation order issued by the respective RPC. The Detailed Procedure for Allocation of Transmission Corridor for Scheduling of General Network Access and Temporary General Network Access "Allocation of Corridor" issued under the GNA Regulations dated 29.9.2023 provides as follows:

"Respective SLDCs on behalf of the intra-state entities which are drawee GNA

grantees or other drawee GNA grantees which are regional entities, shall furnish the details of the contracts (which may include power purchase agreements (PPAs) or Letters of Award (LOA)or
any other type of contract) already entered into by such entities two days before the day when
scheduling request is to made (<u>(i.e. for scheduling for 'S' day, scheduling request is placed on 'S-1' day, copy of the contract may be submitted by 11:00 hrs of 'S-3' day)</u> so as to configure
these details in the scheduling system. In case contracts have not been entered into by S-3
day, contracts are required to be submitted at least one time block before the time block when
the scheduling request is made."

14.3.2. The timeline to furnish allocation Order shall be considered as per the above timeline.

14.3.3. The provision as proposed in the Draft Regulations has been retained.

15. General Provisions (Regulation 45 (7))

15.1. **Commission's Proposal**

15.1.1. The Commission had proposed the following in Regulation 45 (7) of the Draft Regulations:

"(7) Area Control Error:
The concerned Load Despatch Centre and other drawee regional entities shall keep their Area Control Error close to zero (0) by deploying reserves and automatic demand management scheme."

15.2. **Comments have been received from SRPC and MSEDCL**

15.2.1. SRPC has suggested that measures like deploying reserves and ADMS may not be sufficient and load shedding or generation reduction may be required to control the ACE.

15.2.2. **MSEDCL** has commented that to keep area control error close to zero in real time, SLDC should primarily make use of power available from back down stations as per MOD principle, followed by the reserves made available by the ancillary services providers. Deployment of ADMS (load shedding) shall always be the last resort. Hence, it is requested that ADMS may be implemented only when it is utmost necessary under a situation when the power flow is causing threat to the grid.

15.3. **Analysis and Decision**

15.3.1. With regard to suggestions of SRPC, it is clarified that the objective of keeping the Area Control Area close to zero have been specified and may be achieved by the Load Despatch Centre and other drawee regional entities by deploying the reserves which includes reduction of generation. Load shedding should not be resorted to unless emergency grid security concerns are there, as commented by MSEDCL.

15.3.2. Regulation 45 (7) of the 2023 Grid Code Regulations have has modified as follows:

"(7) Area Control Error:
The concerned Load Despatch Centre and other drawee regional entities shall keep their Area Control Error close to zero (0) by <u>rescheduling</u>, deploying reserves and automatic

demand management scheme."

16. General Provisions (Regulation 45 (8) (a))

16.1. Commission's Proposal

16.1.1. The Commission had proposed the following in Regulation 45 (8) (a) of the Draft Regulations:

"(8) Declaration of Declared Capacity by Regional entity generating stations
(a)The regional entity generating station shall declare ex-bus Declared Capacity, limited to 100% MCR, on day ahead basis as per provisions of Regulation 47 of these regulations.
Provided that in case of REGS or ESS the available capacity shall be declared by such regional entity generating station."

16.2. Comments have been received from SJVN, NTPC, NHPC, Tehri HPP, Sembcorp and POSOCO

16.2.1. **SJVN Ltd.** has suggested that Run-of-river power stations with pondage and storage type power stations are designed to operate during peak hours to meet system peak demand. The maximum capacity of the station declared for the day shall be equal to the installed capacity, including overload capability, if any, minus auxiliary consumption, corrected for the reservoir level. RLDC shall ensure that generation schedules of such types of stations are prepared and the stations despatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints.

16.2.2. **NTPC** has suggested that the provisions under 2010 Grid Code may be continued related to restriction of schedule upto 100% of normative ex-bus capacity and the declaration of Declared Capability (DC) as the prerogative of the generator. The restriction on DC shall be an additional loss to the generator(s).

NTPC further submitted that hydro generating stations have been permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods, therefore for such generating stations declared capacity should not be restricted to 100%.

16.2.3. **NHPC, SJVN** have suggested a modification in the clause,

"…limited to 100% MCR <u>or installed capacity including overload capability, if any, minus auxiliary consumption (depending on availability of fuel/inflow)</u> on a day ahead basis…"

16.2.4. **Tehri HPP** has suggested that the declaration of the generating capacity beyond 100% MCR including overload capacity is the prerogative of generators. Limiting it to 100 % MCR will not only impact the calculation of PAF but will also further demoralise the generators in utilizing their overload capacity for rendering a mandatory 5% primary response.

16.2.5. **Sembcorp** has commented that for RE generators, the 'Available Capacity' is defined in the Deviation Settlement Mechanism and Related Matters) Regulations, 2022.

16.2.6. **POSOCO** has commented that DC may be limited to 100% of MCR minus Aux. consumption as DC is the Ex-Bus capacity of the generating station and shall not be more than 100% MCR minus Aux. Consumption.

16.3. Analysis and Decision

16.3.1. With regard to suggestions that declaration of Declared Capacity (DC) be the prerogative of the generators and it should not be restricted to 100% of MCR, it is clarified that the rationale for DC restriction was given in the Explanatory Memorandum to the Draft Grid Code Regulations, 2022 as follows:

"8.4. ..

(d) Declaration of Declared Capacity by Regional entity generating stations

(i) The declaration of DC has been proposed to be capped at 100% MCR considering that maximum schedule that can be given to such a generating station has been limited to 100%, considering mandatory margin to be kept for primary response under Regulation 47(2)(b) of draft Grid Code. It has been brought to the notice of the Commission that in some cases thermal generating stations have been declaring DC beyond 100% i.e. even for the capacity which cannot be scheduled under the 2010 Grid Code. The DC is an offer by generating stations to its buyers to schedule power. The DC against which schedule cannot be given is not appropriate. Accordingly, it has been stipulated that the DC shall be capped at 100%."

16.3.2. We observe that scheduling for overload capacity is allowed for hydro generating stations during a high inflow period and accordingly, DC during such a high inflow period can be more than 100%, where the high inflow periods should be notified by the respective RPC.

16.3.3. With regard to suggestions of Sembcorp, the clause has been modified to specify the declaration of available capacity by WS sellers.

16.3.4. Regulation 45 (8) (a) of the 2023 Grid Code Regulations have been modified as follows:

"(8) Declaration of Declared Capacity by Regional entity generating stations

(a) The regional entity generating station other than the WS seller shall declare ex-bus Declared Capacity limited to 100% MCR less auxiliary power consumption, on day ahead basis as per the provisions of Regulation 49 of these regulations:

Provided that the hydro generating stations may declare ex-bus Declared Capacity more than 100% MCR less auxiliary power consumption limited to overload capability in terms of sub-clause (a) of clause (10) of this Regulation during high inflow periods:

Provided further that a high inflow period for this purpose shall be notified by the respective RPC."

17. General Provisions (Regulation 45 (8) (b))

17.1. Commission's Proposal

17.1.1. The Commission had proposed the following in Regulation 45 (8) (b) of the Draft Regulations:

"(b)The regional entity generating stations may be required to demonstrate the declared capacity of their generating stations as and when directed by the concerned RLDC. For this purpose, RLDC, in coordination with SLDC and the beneficiaries, shall schedule the regional entity generating station upto its declared capacity as declared on day ahead basis at time of first declaration. RLDC shall ask each generating station, at least once in a year, to demonstrate the declared capacity."

17.2. **Comments have been received from UPSLDC, Jindal India TPL, NTPC Sembcorp, WRPC, Torrent Power, and POSOCO.**

17.2.1. UPSLDC has suggested that their demonstration of declared capacity by generating stations might be done on a half yearly basis and/or as required by RLDC.

17.2.2. **Jindal India TPL** has suggested that only the generating station with at least 85% power tied up under Long/Medium term contracts should be eligible to demonstrate the declared capacity. Jindal India TPL has commented that DC declaring is a part of the contract between the Sellers and Buyers, there is no requirement to demonstrate DC to RLDC every year.

17.2.3. **Sembcorp** has commented that Wind and/or solar RE generators may not be able to demonstrate the declared capacity of their generating stations as and when directed by the concerned RLDC, as their generation depends on wind/solar resources that are beyond the control of the generator.

17.2.4. **WRPC** has commented that the beneficiary who seeks the check on the faithful declaration shall bear the financial implications. In the case of annual checking, it is observed that mis-declaration generally occurs during the lean period and therefore this check should be performed during the lean period.

17.2.5. **NTPC** has requested that the phrase “at the time of first declaration” be clarified. There may be a reduction in DC due to genuine issues of some equipment tripping or a change in coal quality. Hence, the demonstration of DC should take into account such issues.

17.2.6. **POSOCO** suggested that as per IEGC, the generator has to demonstrate its first DC declared during "D-1". During the day of operation, however generators are entitled to revised DC as per their fuel supply or any other condition as stipulated in the Grid code. So the testing may be done on the capacity declared at the time of instructions issued by concerned RLDCs for future blocks. Further testing of all the generators in a year may be difficult as beneficiaries are giving requisitions based on the merit order. It is expected that the plant may get a full schedule during peak hours only. Generally, any testing during peak hours is avoided for system security. So, the duration may be reviewed. **POSOCO** has also suggested that the scheduling and settlement for DC testing of generating stations other than section 62 may also be mentioned.

17.2.7. **Torrent Power** has suggested that all the costs associated with periodical demonstration of DC may be directly borne by the respective RLDC/SLDC. This cost, in turn, would be passed on to all the concerned stakeholders through the applicable tariff exercises.

17.3. **Analysis and Decision**

17.3.1. Suggestions of Sembcorp to exempt wind and solar generators have been accepted.

17.3.2. Some stakeholders have suggested a change in the duration for conducting the demonstration of Declared Capacity (DC) by the generating stations. POSOCO has also expressed concerns about the feasibility of conducting the DC demonstration for all generating stations within a year and suggested that the same may be reviewed. Taking into consideration the views of the stakeholders, the mandatory requirement of conducting a demonstration in one year has been deleted and has been left to the prudence of the concerned RLDC.

17.3.3. The suggestions of Jindal India TPL to call for DC demonstration only in case of power tied up is of more than 85% is not accepted since all entities should declare DC faithfully, which can be checked by RLDC.

17.3.4. Further, with regard to comments of POSOCO about DC revision for fuel supply, it is clarified that once a generating station declare DC at 6 AM on 'D-1' day for the next day, it is required that it declares DC keeping in view fuel availability. Hence, a such generating station should be able to demonstrate DC which it declared on'D-1' unless it is under forced outage or partial outage as allowed subsequently in 18/SM/2023.

17.3.5. With regard to clarification sought by POSOCO about the requirement of DC testing for generating stations other than under Section 62, it is clarified that all generating stations are covered by the said Regulation.

17.3.6. With regard to suggestions of Torrent Power, it is clarified that since during the demonstration generating station would be given a schedule, the corresponding schedule on the beneficiary is binding as per sub-clause (c).

17.3.7. Regulation 45 (8) (b) of the 2023 Grid Code Regulations has been modified as follows:

"(b) <u>Regional entity WS Seller shall declare the available capacity on day ahead basis, as per the provisions of Regulations 49 of these regulations</u>. The regional entity with generating stations <u>other than WS sellers</u> may be required to demonstrate the declared capacity of their generating stations as and when directed by the concerned RLDC. For this purpose, RLDC, in coordination with SLDC and the beneficiaries, shall schedule the regional entity generating station up to its declared capacity as declared on day ahead basis."

18. General Provisions (Regulation 45 (8) (c))

18.1. Commission's Proposal

18.1.1. The Commission had proposed the following in Regulation 45 (8) (c) of the Draft Regulations:

"(c)The schedule issued by the RLDC shall be binding on the beneficiaries for such testing of declared capacity of the regional entity generating station. In case the generating station fails to demonstrate the declared capacity, it shall be treated as mis-declaration for which charges shall be levied on the generating station by RPC as follows:

The charges for the first mis-declaration for a block or multiple blocks in a day shall be the charges corresponding to two days fixed charges at normative availability. For the second mis-declaration, the charges shall be corresponding to four days fixed charges at normative availability and for subsequent mis-declarations, the charges shall increase in a geometric progression over a period of a month."

18.2. Comments have been received from SRPC, Tata Power, Nabha Power

18.2.1. **SRPC** has suggested that the word "a period of the month" may be replaced with "Financial Year".

18.2.2. **Tata Power** commented that, in case the generator has been declaring full DC without running upto its full capacity and, at the time of testing plant is not able to generate upto its declared capacity, the DC of the plant should be revised to the actual (MW) capacity it was able to demonstrate, for a timeframe as decided/deemed fit by the Appropriate Authority.

18.2.3. **Nabha Power** has suggested that the penalty clause should be reduced and should only be levied in the case of intentional mis-declaration made by a generator to make an undue commercial gain. Unintentional mis-declarations such as GCV variation of fuel for a short period of time should not be considered as mis-declarations.

18.3. **Analysis and Decision**

18.3.1. With regard to suggestions of SRPC to replace month with year is not accepted since the penalty should increase every month to ensure faithful declaration of DC.

18.3.2. With regard to suggestions of Tata Power, it is clarified that demonstration would be carried out by RLDC only occasionally, and not regularly. It is expected that the generating station is providing DC faithfully. However, if misdeclaration is established, additional charges should be levied to ensure that DC is declared faithfully.

18.3.3. With regard to suggestions of Nabha Power, it is clarified that the clause includes the first mis-declaration, the second mis-declaration, and so on. A generating station should faithfully establish the DC based on fuel quality etc.

18.3.4. The provision as proposed in the Draft Regulations has been retained.

19. General Provisions (Regulation 45 (9) (a))

19.1. **Commission's Proposal**

19.1.1. The Commission had proposed the following in Regulation 45 (9) (a) of the Draft Regulations:

"(9) Ramping Rate to be Declared for Scheduling:

(a) The regional entity generating station shall declare the ramping rate along with the declaration of day-ahead declared capacity in the following manner, which shall be accounted for in the preparation of generation schedules:

(i)Coal or lignite fired plants shall declare a ramp up or ramp down rate of not less than 1% of ex-bus capacity corresponding to MCR on bar per minute;

(ii) Gas power plants shall declare a ramp up or ramp down rate of not less than 3% of ex-bus capacity corresponding to MCR on bar per minute;

(iii) Hydro power plants shall declare a ramp up or ramp down rate of not less than 10% of ex-bus capacity corresponding to MCR on bar per minute;

(iv) Renewable Energy generating station shall declare a ramp up or ramp down rate as per CEA Connectivity Standards."

19.2. **Comments have been received from IWPA, NHPC, Tata Power, Adani Power, APP, Jindal India TPL, Sembcorp and Torrent Power, NTPC, Nabha Power and OTPC.**

19.2.1. **IWPA** has commented that it is not possible for wind and solar generators to ramp up / ramp down their output since their generation solely depends on the wind speed/Solar insolation. Since the wind speed and Solar insolation, itself are varying in nature, wind and solar generators may be exempted from this requirement.

19.2.2. **NHPC** has commented that the ramping rate of a hydro power station is not a variable parameter. The ramping rate of each generating unit may be obtained once a year, and the same can be tested if required. Data can be used by RLDC for the corresponding year. Daily punching of Ramp-rate may not be required.

19.2.3. **Tata Power** has suggested that plants under section 62 are proposed to be incentivised as ROI for providing a 1% ramp rate as per regulation, whereas plant under section 63 have been excluded from such financial benefit. Thus, plants under section 63 also need to be included in this regulation for incentives.

19.2.4. **Adani Power and APP** have suggested that the ramp rate can vary depending on the equipment condition and coal quality. The generator should be allowed to declare ramp the rate accordingly.

19.2.5. **Jindal India TPL** has commented that Ramp up or ramp down depends on O&M manuals provided by equipment suppliers and any Unit needs to operate as per O&M manuals for safe and reliable plant operation.

19.2.6. **Sembcorp** has commented that based on details regarding the plants being operated by Sembcorp, 0.7% ramp rates are sustainable for a wide range of 50% to 100% load variation. 1% can be achieved only for short ranges of 20%. Ramp rates may be specified based on design parameters or the capability of the plants.

19.2.7. **Torrent Power** has commented that each generating station has unique characteristics. Ramp up or ramp down depends on the unit capacity, wherein operating conditions vary based on the class of machine used. The existing grid code duly acknowledges the same and has duly considered the ramp up and ramp down rates. It is requested to retain the existing levels of ramp up or ramp down rates for gas power plants.

19.2.8. **NTPC** has commented that the system operator shall consider the ramp rate declaration appropriately while revising the schedule of the generator so that it does not lead to unacceptably large steps and no DSM liability occurs to the Generator on account of above.

19.2.9. **Nabha Power** has suggested that the ramp-up and ramp down rates should be as per design parameters as per OEM.

19.2.10. **OTPC** has requested the Commission to exempt Palatana from the requirements of a ramp rate of 3% of ex-bus capacity corresponding to MCR on bar per minute.

19.3. **Analysis and Decision**

19.3.1. The suggestion of IWPA to exempt RE generators are not accepted since RE generators need to be designed and installed to comply with the CEA Technical Standards.

19.3.2. With regard to suggestions of NHPC not to punch ramp rate on a daily basis, and take default rates, it is suggested that the same can be incorporated in software by RLDC.

19.3.3. The suggestions of Tata Power to provide incentives for achieving a Ramp rate of 1% by Section 63 projects are beyond the scope of the present draft Regulations.

19.3.4. With regard to suggestions by other generating stations to link ramp rate to OEM parameters or leave it at the discretion of the generator, it is clarified that CEA Standards require a ramp rate of 3% for coal-based plants. Accordingly, the plants should be designed to achieve at least 3% as per CEA Standards. Further, the ramp rate plays a very important role in the integration of RE. The mandatory requirement under the 2023 Grid Code is at least a 1% ramp rate, to which the generating stations should comply.

19.3.5. With regard to submissions of OTPC to exempt Palatana from the 3% ramp rate, it is clarified that gas generating stations have a high ramping rate. However, in case of any specific technical difficulty, appropriate application may be made specifying such difficulty while seeking exemption.

19.3.6. The provision as proposed in the Draft Regulations has been retained.

20. General Provisions (Regulation 45 (10) (a) & (b))

20.1. **Commission's Proposal**

20.1.1. The Commission had proposed the following in Regulation 45 (10) (a) & (b) of the Draft Regulations:

"(10) Optimum Utilization of Hydro Energy

(a) During high inflow and water spillage conditions, for Storage type generating station and Run–of-River Generating Station with Pondage, the declared capacity for the day may be upto the installed capacity plus overload capability (upto 10%) minus auxiliary consumption, corrected for the reservoir level.

(b) During high inflow and water spillage conditions, the concerned RLDC shall allow scheduling of power from hydro generating stations for the overload capability upto 10% of Installed capacity without the requirement of additional GNA for such overload capacity, subject to availability of margins in the transmission system."

20.2. **Comments have been received from ReNew Power, Statkraft, Hero Future Energy, Enel, Greenko, O2 Power, Renew Power, National Solar Federation, Tata Power, AD Hydro Ltd., and POSOCO.**

20.2.1. ReNew **Power** and **Statkraft** have suggested changing the overload capacity to 20% instead of 10%. The inherent machine capability (as certified by the manufacturer) in some of the hydro projects has an overload capacity of 20% (which can be used only during peak season). Such overload capacity should be allowed to be injected.

20.2.2. **AD Hydro Ltd.** has commented that during the high flow season, the restriction of overload capacity upto 10% should not be imposed on all types of ROR Plants and these Plants should be allowed to run on overload as guaranteed by the Original Equipment Manufacturer (OEM).

It is suggested that the Grid Code should allow the Generators to generate at full load plus overload as guaranteed by the OEM for the optimum utilization of the high inflow during monsoon season.

20.2.3. **POSOCO** has suggested that, at present during spillage, the hydro generator is allowed to submit DC upto 110% of IC. However, as per the draft IEGC, they are allowed to declare DC untill 110%IC-Aux. Consumption.

20.2.4. **Hero Future Energy, Enel, Greenko, O2 Power, Renew Power, National Solar Federation,** and **Tata Power** have suggested that solar Projects are generally installed with high DC capacity, and there may be scenarios wherein power limited to contracted capacity is flowing out and inverter having an inherent margin of 5 to 10% beyond the rated capacity. It is requested that the same should be allowed to be injected like a hydro power plant in case of a high insolation period or shortage scenario.

20.3. **Analysis and Decision**

20.3.1. The suggestions of Renew Power, Statkraft, and AD Hydro to allow overload capability beyond 10% during periods of high inflow and water spillage conditions as per OEM have been considered and accepted. However, it is observed that in a hydro generating station, apart from machine capability, other hydro parameters and structures also need to be verified to sustain generation at such overload. Accordingly, it has been provided that the proposed increase in the overload limit beyond 10% should be certified by the OEM and approved by the CEA.

20.3.2. The suggestions of stakeholders to provide for scheduling overload capability in RE generating stations are not accepted. A wind or solar generating station is not designed with overload capability under the CEA Technical Standards as in the case of hydro or thermal generating stations. Accordingly, a Solar or Wind generating station can seek Connectivity (converted to deemed GNA) equal to the quantum it needs to get scheduled.

20.3.3. With regard to suggestions of POSOCO, it is clarified that DC may be declared upto installed capacity plus overload capability (as approved) minus auxiliary consumption.

20.3.4. Regulation 45 (10) (a) & (b) of the 2023 Grid Code Regulations have been modified as follows:

"(10) Optimum Utilization of Hydro Energy:

(a) During high inflow and water spillage conditions, for Storage type generating station and Run–of-River Generating Stations with or without Pondage, the declared capacity for the day may be up to the installed capacity plus overload capability <u>(up to 10% or such other limit as certified by the OEM and approved by CEA)</u> minus auxiliary consumption, corrected for the reservoir level. <u>In case, the overload capability of such a station is more than 10% as approved, such a station shall declare the overload capability in advance.</u>

(b) During high inflow and water spillage conditions, the concerned RLDC shall allow scheduling of power from hydro generating stations for overload capability up to 10% of Installed Capacity or any other limit as per sub-clause (a) of this clause without the requirement of additional GNA for such overload capacity, subject to the availability of margins in the transmission system."

21. General Provisions (Regulation 45 (11) (a))

21.1. **Commission's Proposal**

21.1.1. The Commission had proposed the following in Regulation 45 (11) (a) of the Draft Regulations:

"(11) Scheduling of renewable energy generating station by QCA

(a)The regional entity renewable energy generating station(s) or Projects based on energy storage system(s) connected at a particular ISTS substation or at multiple ISTS substations may appoint a QCA on their behalf to coordinate and facilitate scheduling for such generating stations or energy storage system(s)."

21.2. **Comments have been received from SRPC, RE Connect Energy and POSOCO**

21.2.1. SRPC has suggested for the addition of the following in the clause, "in a Region" after "at multiple ISTS substations", as Pooling by QCA among different regions would be difficult for DSM and grid management by RLDCs. Therefore, QCA may be allowed to pool RE entities within a Region only.

21.2.2. **RE Connect Energy** has suggested that "QCA or Forecasting Agency" may be considered in the clause instead of "QCA".

21.2.3. **POSOCO** has suggested that the regional entity renewable energy generating station(s) or Projects based on the energy storage system(s) connected at a particular ISTS Pooling substation may appoint a QCA on their behalf to coordinate and facilitate scheduling for such generating stations or energy storage system(s).

21.3. **Analysis and Decision**

21.3.1. The Commission has noted the suggestions of the stakeholders.

21.3.2. With regard to suggestions of SRPC, the Commission is of the view that pooling by QCA, for now, is allowed maximum for ISTS substations located in a State and not across states. DSM is a mechanism that ensures actuals are maintained close to schedule, whereas when schedules and actuals across substations are pooled, there may be over injection at one substation and under injection at another substation, and pooled together may be with zero deviation. In such a case, over injection as well as under injection may create grid security issues. Accordingly, the procedure by NLDC for aggregation of pooling stations within the State would need to consider grid security aspects while suggesting pooling.

21.3.3. With regard to suggestions of RE Connect, it is clarified that QCA would also act as a forecasting agency as defined in its role, and separate inclusion by another name is not required.

21.3.4. The suggestions of POSOCO have been accepted, and ESS has also been inserted in sub-clause(d) of Regulation 45(11) of the 2023 Grid Code, enabling multiple ESS or a mix of ESS and REGS to appoint QCA.

21.3.5. Regulation 45 (11) (a) of the 2023 Grid Code Regulations have been modified as follows:

"(11) Scheduling of <u>WS seller and ESS</u> by QCA:

(a) The regional entity renewable energy generating station(s) or Projects based on energy storage system(s) connected at a particular ISTS substation or at multiple ISTS substations <u>located in a State</u> may appoint a QCA on their behalf to coordinate and facilitate scheduling for such generating stations or energy storage system(s). <u>The responsibility of QCA is listed at Annexure-6 to these regulations."</u>

22. General Provisions (Regulation 45 (11) (b))

22.1. **Commission's Proposal**

22.1.1. The Commission had proposed the following in Regulation 45 (11) (b) of the Draft Regulations:

"(b) NLDC shall notify a procedure for aggregation of pooling stations for the purpose of combined scheduling and deviation settlement for wind or solar or renewable hybrid generating stations within six (6) months of notification of these regulations."

22.2. **Comments have been received from SECI, APP, Adani Power, AGEL, Enel, Greenko, ReNew, National Solar Federation, Tata Power, Hero Future Energy, WIPPA, O2 Power and POSOCO.**

22.2.1. **SECI** has suggested that the "Renewable Hybrid Generating Stations" may be substituted with "Energy Storage Systems".

22.2.2. **APP, Adani Power, and AGEL** have suggested that the procedure for aggregation of pooling stations may have an impact on Annexure-5, the Procedure specifying data, forecasting, and scheduling for renewable energy generating stations (REGS) at the Inter-state level and the CERC (Deviation Settlement Mechanism and Related Matters) Regulation 2022 and have requested to issue procedure along with Grid Code as Annexure and corresponding amendments in the DSM Regulation 2022.

22.2.3. **Enel, Greenko, ReNew, National Solar Federation, Tata Power and Hero Future Energy** have suggested modifications in the clause as follows:

> "NLDC shall notify a procedure for aggregation of pooling stations and <u>at regional level</u> for the purpose of combined scheduling and deviation settlement for wind or solar or renewable hybrid generating stations within six (6) months of notification of these regulations.
>
> <u>Provided further that aggregated deviation at regional level shall be charged from such Wind and Solar Generator on proportionate to their individual deviation."</u>

The state level aggregation of schedules by a QCA is being implemented by Karnataka and Andhra Pradesh. States follow one of three levels of aggregation of scheduling, i.e., plant-level, pooling station-level, and State-level. This specific element of the regulations has material implications for the long term viability of RE projects in India.

22.2.4. **WIPPA** and **O2 Power** have suggested that the word "of pooling stations" may be deleted from the clause.
Any commercial impact due to imbalance should be handled at the LDC level only, and the same should preferably be socialized over grid costs, or there should be some appropriate formula to share settlement with various developers over the state/ region.

22.2.5. **POSOCO** has suggested that for intra-state RE plants, the payments to wind and solar plants are based on actual generation (which means Post-facto schedule revision), and the SERC Regulations give the options for de-pooling the DSM amounts, which could be agreed upon by the QCA with its members. In the case of ISTS connected RE plants, where payments to RE plants are based on schedules, de-pooling would give rise to disputes. Since there is not enough clarity on the topic in DSM Regulations, it is desired that the same may be specified in the Grid Code.

22.3. **Analysis and Decision**

22.3.1. **With** regard to suggestions of SECI to include ESS, it is clarified that ESS is already included under Regulation 45(11) and, accordingly, it is also applicable to Regulation 45(11)(b).

22.3.2. With regar to suggestions of APP, Adani Power, and AGEL, it is clarified that necessary details of aggregation of pooling stations shall be covered under the NLDC Procedure and any changes required in any other Regulations, shall be taken up as and when required.

22.3.3. The suggestions of Enel, Greenko, ReNew, National Solar Federation, Tata Power and Hero Future Energy to consider pooling at the regional level are not accepted, as explained in reasons under Regulation 45(11)(a) above. Further, it is clarified that de-pooling shall be agreed between generating stations and QCA.

22.3.4. With regard to suggestions of WIPPA and O2 Power to delete 'of pooling stations', it is clarified that aggregation is proposed only for ISTS pooling stations located in a particular State and that too to be as proposed by NLDC in the detailed Procedure considering transmission system and grid security.

22.3.5. With regard to suggestions of POSOCO to clarify the de-pooling arrangement, it is clarified that the de-pooling arrangement shall be as agreed between QCA and generators. In case QCA is not appointed, detailed scheduling and accounting arrangements have been provided in Annexure to the 2023 Grid Code.

22.3.6. Regulation 45 (11) (b) of the 2023 Grid Code Regulations have been modified as follows:

"(b) NLDC shall submit a procedure for aggregation of pooling stations for the purpose of combined scheduling and deviation settlement for wind or solar or renewable hybrid generating stations <u>that are regional entities</u>, within six (6) months of notification of these regulations <u>for approval of the Commission</u>."

23. General Provisions (Regulation 45 (11) (d))

23.1. **Commission's Proposal**

23.1.1. The Commission had proposed the following in Regulation 45 (11) (d) of the Draft Regulations:

"(d) QCA registered with the concerned RLDC shall, on behalf of wind, solar or renewable hybrid generating stations:"

23.2. **Comments have been received from SECI.**

23.2.1. SECI has suggested the addition of an Energy Storage System

23.3. **Analysis and Decision**

23.3.1. Considering the suggestions of SECI, the clause has been modified as follows,

"(d) QCA registered with the concerned RLDC shall, on behalf of wind, solar or renewable hybrid generating stations <u>or Energy Storage System shall</u>:"

24. General Provisions (Regulation 45 (11) (f))

24.1. **Commission's Proposal**

24.1.1. The Commission had proposed the following in Regulation 45 (11) (f) of the Draft Regulations:

"(f) Any dispute arising between the generating stations and QCA shall be resolved in accordance with the mechanism in the contracts entered into between them."

24.2. **Comments have been received from Greenko, Enel, Renew, Sembcorp, WIPPA, Hero Future Energy, and the National Solar Energy Federation.**

24.2.1. **Greenko, Enel, Renew, Sembcorp, WIPPA, Hero Future Energy** and **National Solar Federation** have suggested that QCA be registered with the concerned RLDC. The Hon'ble Commission is requested to notify qualifying criteria, net worth, creditworthiness etc. Moreover, any dispute resolution between Generating Station/QCA should be under the jurisdiction of CERC.

24.3. **Analysis and Decision**

24.3.1. It is clarified that QCA would be acting on behalf of generating stations as per the contract entered into between QCA and generating stations and dispute resolution would be as per contract and the contract act. The regulation has been modified to clearly provide for dispute resolution.

24.3.2. Regulation 45 (11) (f) of the 2023 Grid Code Regulations has been modified as follows:

"(f) <u>Contract between the generating stations and QCA shall invariably contain provisions for internal dispute resolution</u>, and any disputes arising between the generating stations and QCA shall be settled in accordance with the said mechanism."

25. General Provisions (Regulation 45 (12))

25.1. **Commission's Proposal**

25.1.1. The Commission had proposed the following in Regulation 45 (12) of the Draft Regulations:

"(12) Minimum turndown level for thermal generating stations
The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of MCR of the said unit:
Provided that the Commission may fix through an order a different minimum turndown level of operation in respect of specific unit(s) of a regional entity thermal generating station:
Provided further that such generating station on its own option may declare a minimum turndown level below 55% of MCR:
Provided also that the regional entity thermal generating stations shall be compensated for generation below the normative level either as per the mechanism in the Tariff Regulations or in terms of the contract entered into by such generating station with the beneficiaries or buyers, as the case may be."

25.2. **Comments have been received from SRPC, KSEBL, KPTCL, PCKL, APP, Adani Power, Dhariwal, Jindal India TPL, MPPMCL, Greenko, National Solar Federation, Enel, Torrent Power, Tata Power, NTPC, MB Power, POSOCO and OTPC.**

25.2.1. SRPC has commented that the CEA (Flexible Operation of thermal power plants) Regulations, 2022 need to be complied with. Further, operating the plant below the mandated Turn Down Level offers flexibility to system operators/beneficiaries and also allows generators to participate in Reserves and the power market.

25.2.2. **KSEBL** has commented that the regulation has taken all steps to insulate the generators from incurring any loss due to the load schedule. The regulation may also look into the financial liability of all the beneficiaries.

25.2.3. **KPTCL** has commented that this particular clause has not considered the reserve shutdown procedure. If a generator needs to be kept under reserve requirement at the national level, then there should not be any forceful scheduling to SLDC. It should be the sole responsibility of the National Load Dispatch Centre to ensure minimum schedule is given to the generator. Hence, existing RSD procedure needs to be retained.

25.2.4. **PCKL** has commented that the procedure for reserve shutdown is not specified.

25.2.5. **APP** and **Adani Power** have highlighted that for super critical units, operation of units at a minimum turndown level of 55% or lower may lead to critical technical issues.

25.2.6. **Adani Power**, **APP** and **Dhariwal, MB Power** have commented that the compensation mechanism due to operation of a Thermal Generating Station below normative level may be applied uniformly to all beneficiaries irrespective of whether the PPAs are executed under Section-62 or Section-63 of the Electricity Act 2003.The existing provisions with respect to compensation mechanisms for Part Load Operations may be retained in the final CERC IEGC Regulations 2022.

25.2.7. **Jindal India TPL** has commented that the minimum plant operation load depends on various O&M manuals of different suppliers for safe and reliable plant operation and suggested adding that "Ex-bus" after "MCR" in the clause.

25.2.8. **MPPMCL** has suggested that the regional entity thermal generating stations shall not be compensated for generation below the normative level in any manner as neither existing PPA provides for such compensation nor the Tariff Regulations provides for such provisions, as the beneficiaries are required to pay the Annual Fixed Charges or capacity charges to generating company according to their DC even in case of non-scheduling of power or unit going under USD thus mitigating the loss. The introduction of the compensation clause is not only against the provisions of PPA but it also results in promoting inefficiency and incapability on the part of generating stations of not offering the energy at competitive energy charges to get sufficient schedule in accordance with merit order dispatch principle.

25.2.9. **Greenko, National Solar Federation** and **Enel** have suggested that the "55% of MCR" may be substituted with "55% or 40% of MCR".

25.2.10. **Torrent Power** has suggested that due to some unforeseen circumstances, generators may sometimes be required to revise the technical minimum in the overall interest of all the stakeholders. Therefore, if such downward revision is agreed to by the generator to reduce cost to the end user, then the generator should also be allowed to have the flexibility for upward revision accordingly.

25.2.11. **Tata Power** has suggested that the IEGC provides compensation for APC and Heat Rate up to 55% MCR only. As generators are now permitted to operate below the minimum turndown level i.e., 55% of MCR, the compensation mechanism may be modified accordingly.

25.2.12. **NTPC** has suggested that the provisions regarding part load compensations in the existing grid code may continue to be effective till part load compensation provisions are made applicable in the tariff Regulations so that the generators continue to receive compensation.

25.2.13. **POSOCO** has suggested that the minimum scheduling limit shall be declared at Ex-Bus after deducting the auxiliary consumption.

25.2.14. **OTPC** has requested the Commission to exempt Palatana from a minimum turndown **level** of 55% and allow a technical minimum of 65% under the petition 278-MP-2019.

25.3. **Analysis and Decision**

25.3.1. The Commission observes that CEA has notified its Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 on 25th January, 2023. The relevant extracts of the said regulation for Minimum power level capabilities of coal based thermal power generating units for flexible operation are as follow:

> *"**6. Minimum power level capabilities of coal based thermal power generating units for flexible operation**.-*
>
> *The coal based thermal power generating units shall have flexible operation capability with minimum power level of forty percent.*
>
> *Provided that the generating units which are not capable of achieving minimum power level of fifty-five percent, shall achieve the same within one year of the notification of these regulations.*
>
> *Provided further that the generating units which are not capable of achieving minimum power level of forty percent, shall achieve the same as per phasing plan mentioned in the sub-regulation (2) of regulation 5 of these regulations."*

In view of the above notified regulation, the Commission has incorporated the enabling provision of minimum power level as specified in the CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023.

25.3.2. The Commission observes that generating units that are not capable of achieving a minimum power level of forty percent shall achieve the same as per the phasing plan specified by CEA from time to time in terms of the CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023. In view of the aforesaid, the comments of some stakeholders regarding the operation of super critical units at a minimum turndown level of 55% or lower, leading to critical technical issues stand addressed.

25.3.3. Some stakeholders have suggested that the financial liability of the beneficiaries may be looked into and to retain the existing RSD procedure. The Commission observes that under the 2023 Grid Code, the concept of reserve shutdown as in the 2010 Grid Code has been replaced with 'Unit shutdown'. Further, in case the generating station opts to go under unit shut down, the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station. Further, With regard to comments of KPTCL regarding forceful scheduling to SLDC, it is clarified that there is no concept of 'forceful scheduling' under the 2023 Grid Code to maintain 'minimum turndown level' as was provided in the Reserve shutdown procedure. Beneficiaries have full freedom to schedule power from a generating station as per its requirements as per the entitlement. In case the system operator requires a generating station scheduled below the Minimum turndown level to not go under USD, he may commit it under SCUC, in which there is no forceful scheduling to beneficiaries.

25.3.4. The suggestions of Adani Power, APP, and Dhariwal to retain the compensation mechanism for the Thermal Generating Station operating below the normative level for Section-63 projects of the Electricity Act 2003 have been accepted. However, it is observed that under the Draft Regulations, detailed parameters for compensation were not proposed since it was proposed that the compensation mechanism for the regional entity thermal generating stations shall be included under Tariff Regulations. Accordingly, without prepublication, parameters for compensation cannot be included in the 2023 Grid Code. Hence, it has been provided that till the time the mechanism for the part load compensation is notified by the Commission, the mechanism already in force under the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 shall continue to be in operation.

25.3.5. With regard to suggestions of POSOCO, it is clarified that the ex-bus number may be calculated by POSOCO after deducting APC.

25.3.6. With regard to comments of OTPC to exempt it from 55% Minimum level, specific exemption may be sought through appropriate application citing continued technical difficulties.

25.3.7. Regulation 45 (12) of the 2023 Grid Code Regulations has been modified as follows:

"(12) Minimum turndown level for regional entity thermal generating stations:
The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of the MCR of the said unit <u>or such other minimum power level as specified in the CEA (Flexible Operation of coal based Thermal Generating Units) Regulations, 2023, as amended from time to time, whichever is lower:</u>

Provided that the Commission may fix through an order a different minimum turndown level of operation in respect of specific unit(s) of a regional entity thermal generating station:
Provided further that such generating station on its own option may declare a minimum turndown level below the minimum turndown level specified in this clause:
Provided also that the regional entity thermal generating stations whose tariffs are determined under Section 62 or Section 63 of the Act, shall be compensated for part load operation, that is, for generation below the normative level of operation, in terms of the provisions of the contract entered into by such generating stations with the beneficiaries or buyers, or in the absence of such provision in the contract, as per the mechanism to be specified by the Commission through separate regulations or through Order:

Provided also that till the mechanism of part load compensation is notified by the Commission, the mechanism in this regard already in force under the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 shall continue to be in operation."

26. General Provisions (Regulation 45 (14))

26.1. **Commission's Proposal**

26.1.1. The Commission had proposed the following in Regulation 45 (14) of the Draft Regulations:

"(14) A generating station or ESS or a drawee entity shall be allowed to schedule injection or drawl only upto its effective GNA quantum or T-GNA quantum, as applicable, in accordance with the GNA Regulations."

26.2. **Comments have been received from NTPC.**

26.2.1. NTPC has suggested that the above clause may not be made applicable for the exchange of infirm power and the requirement of taking TGNA during infirm power exchange may please be dispensed with, and the exchange of infirm power may be allowed upto the permission granted by the grid operator after payment of transmission charges as applicable.

26.3. **Analysis and Decision**

26.3.1. With regard to suggestions of NTPC, it is clarified that T-GNA is obtained only by buyers. For injecting entities, the quantum of power scheduled is under GNA or considered as deemed T-GNA if its GNA is not effective, where the generating station is not required to apply for T-GNA. However, if a generating station wishes to draw power, it needs to apply for T-GNA.

26.3.2. The provision as proposed in the Draft Regulations has been retained.

27. General Provisions (Regulation 45 (15))

27.1. **Commission's Proposal**

27.1.1. The Commission had proposed the following in Regulation 45 (15) of the Draft Regulations:

"(15) A generating station including renewable energy generating station shall be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, only after obtaining schedule for such drawal of power in accordance with a valid contract entered into by it with a seller or distribution licensee or through power exchange."

27.2. **Comments have been received from PTC, NTPC, Adani Power, APP, AGEL,**

Sembcorp, O2 Power, WIPPA, SJVN, Dans Energy, OTPC.

27.2.1. PTC India has suggested that to define the term "non-generation hours".

27.2.2. **NTPC** has suggested that the requirement of drawal of power by a thermal generator during unit tripping, considering a process requirement and drawal of start-up power may be allowed under DSM and considered drawal under deemed TGNA.

27.2.3. **Adani Power, APP,** and **AGEL** have suggested promoting RE generation to allow drawal by RE generators during non-generating hours without the requirement of a valid contract or drawl schedule.

27.2.4. **Sembcorp** commented that the above clause should not be applicable for wind generators drawing power for start-up or for other auxiliary consumption. For wind generators, it is impossible to accurately predict non-generation hours due to the variability of wind. Most wind generators face sudden drops in wind resulting in nil generation that cannot be predicted. Hence, it will be very difficult (rather impossible) for wind generators to enter into contracts for start-up power without accurately knowing when start up would be required.

27.2.5. **O2 Power** and **WIPPA** have suggested that a generating station, including a renewable energy generating station. should be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, can procure power from the grid, and the same would be netted off with the energy injected into the grid in generating hours.

27.2.6. **SJVN** has suggested that hydro generators should be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, and the same shall be adjusted against the schedule after the day is over or as a process requirement drawl of power by hydro a generator during unit start- stop may please be continued to be allowed under DSM.

27.2.7. **Dans Energy** has suggested that renewable energy sources including hydro generating stations should be allowed to draw power during non-generation hours.

27.2.8. **OTPC** has requested the Commission to continue with the present mechanism of Deviation Settlement for power drawal needs of stations.

27.3. **Analysis and Decision**

27.3.1. The Commission has noted the suggestions of the stakeholders.

27.3.2. With regard to clarification sought by PTC for "non-generation hours", it is clarified that when a generating station is not generating power, they are "non-generation hours", for example, a solar generating station, not generating power during night, are the non-generation hours for solar generating station. When a generating station is generating power, the need to draw power from the grid may not arise.

27.3.3. With regard to suggestions of a number of stakeholders to allow drawal of power before or after COD under DSM, the same has been permitted under the instant clause, with the condition that the generating station should endeavour to enter into a contract for such power. However, if it is not able to enter into a contract, it can draw power under DSM. It is noted that the grid is not a supplier of power, unless some injecting entity injects power, it should not be drawn. Further, with the increasing penetration of RE more and more power is likely to be drawn under DSM, which is required to be managed by the system operator. It is also clarified that when the power is drawn under DSM, it is not under deemed T-GNA. Further, if the generating station enters into a contract with another seller to supply such start-up power, the generating station needs to take T-GNA to schedule such drawl of power under T-GNA.

The Commission, in the Draft regulation, has proposed that a generating station, including renewable energy generating station shall be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, only after obtaining schedule for such drawal of power in accordance with a valid contract entered into by it with a seller or distribution licensee or through power exchange. The rationale for the same has been given in Para 8.4(i) of the Explanatory Memorandum to the Draft Grid Code Regulations 2022. However, most of the stakeholders have suggested allowing them to meet the power requirements during non-generation hours under DSM. The Commission would like to emphasise that drawal of power during non-generation hours without having a valid contract with a seller/distribution licensee/through power exchange shall lead to an imbalance in the system. The basic purpose is that the generating stations should make necessary arrangements for entering into contracts with a seller/scheduled transaction for meeting their drawal of power during non-generation hours.

27.3.4. Regulation 45 (15) of the 2023 Grid Code Regulations has been modified as follows:

"(15) For meeting its power requirements during non-generation hours, whether before or after COD, a generating station, including renewable energy generating station, shall enter into a valid contract with a seller or distribution licensee or through power exchange:

<u>Provided that where the generating station including a renewable energy generating station is unable to enter into a contract for the drawal of power during non-generation hours, it may draw power from ISTS on payment of deviation charges as per the DSM Regulations."</u>

28. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (a))

28.1. **Commission's Proposal**

28.1.1. The Commission had proposed the following in Regulation 46 (4) (a) of the Draft Regulations:

"(4) The SCUC may be undertaken on day ahead basis, in respect of the generating stations or units thereof, for which tariffs are determined by the Commission under section 62 of the Act, as per the following process:
(a) By 1330 Hrs of D-1 day, 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turn down level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in power exchanges, received till 1300 Hrs of the D-1 day."

28.2. **Comments have been received from MPPMCL and Dhariwal.**

28.2.1. **MPPMCL** has suggested that the Timing may be considered as "By 15:30 Hrs**"**

28.2.2. **Dhariwal** has suggested that participation under SCUC should also be allowed to generating companies under Section 63 of the Act.

28.3. **Analysis and Decision**

28.3.1. With regard to suggestions of MPPMCL, the timeline has been changed from 1330 hrs. as proposed in the Draft regulation to 1400 hrs so as to be in sync with the timeline for processing the exigency applications. It is also clarified that the timeline has been kept as earliest possible as it would help to provide ample time for starting any unit under warm or hot start condition, if required.

28.3.2. The suggestions of Dhariwal to include generating stations other than under Section 62 have been accepted and accordingly sub-clause(j) has been inserted as follows:

"(j) The generating stations other than those whose tariffs are determined under Section 62 of the Act may opt to participate in SCUC as per the Detailed Procedure to be prepared by NLDC and approved by the Commission."

28.3.3. Regulation 46 (4) (a) of the 2023 Grid Code Regulations has been modified as follows:

"(4) The SCUC may be undertaken on day ahead basis, in respect of the <u>regional entity</u> generating stations or units thereof, for which tariffs are determined under section 62 of the Act, as per the following process:

(a) By <u>1400</u> Hrs of D-1 day, 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turndown level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in the power exchanges, received till 1300 Hrs of the D-1 day."

29. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (b))

29.1. Commission's Proposal

29.1.1. The Commission had proposed the following in Regulation 46 (4) (b) of the Draft Regulations:

"(b) Beneficiaries of such stations, whose units are likely to be scheduled below minimum turndown level for some or all time blocks of the D day, shall be permitted to revise their requisitions from such stations by 1630 Hrs of D-1 day, in order to enable such units to be on bar. The revised requisition from the said generating stations, once confirmed by the beneficiaries by 1630 Hrs of D-1 day, shall be final and binding after 1630 Hrs of D-1 day and further reduction in drawal schedule shall not be allowed from such stations for such time blocks."

29.2. Comments have been received from PTC, PCKL, KSEBL, PSPCL, WBSEDCL, BYPL and MPPMCL

29.2.1. **PTC** has suggested that as per the clause, beneficiaries cannot revise the schedule after 16:30 hours of D-1 day even after paying the fixed cost as per Declared Capacity. The beneficiary is subject to a loss, so revision rights should remain with the beneficiary even after 1630 hours.

29.2.2. **PCKL and KSEBL** have suggested that in real time there is variation in RE generation and demand hence there should be flexibility for the reduction of drawal schedule as per the extant regulation.

29.2.3. **PSPCL** has suggested that time line to revise requisition from the stations whose units are likely to be scheduled below minimum turndown level for some or all-time blocks of the D day, shall be permitted till at least 1730 Hrs of D-1 day instead of 1630 hrs.

29.2.4. **WBSEDCL** has suggested that with the implementation of this clause, the beneficiary of the ISGS whose tariff is determined under section 62 and 63 of IE Act 2003, will lose the right of real time revision despite paying the fixed cost to the stations.

Moreover, such relinquishment of the right to revision through this regulation will cause deviation from the provision of the agreement between DISCOMs and the generating stations. The main intention of this regulation is to maximize the operational reserves in the interest of grid security which may be alternatively assured by the untied capacity of the ISGS, Stressed Asset and Gas based Power Stations, which is now usually under continuous forced shutdown condition.

29.2.5. **BYPL** has suggested that one opportunity should be provided to the beneficiaries to reduce the drawal schedule before considering it final.

29.2.6. **MPPMCL** has suggested that the time under the clause may be considered as 17:30 Hrs.

29.3. **Analysis and Decision**

29.3.1. With regard to suggestions of PTC, BYPL and WBSEDCL, it is clarified that upward revision in schedule is permitted for the quantum not kept as reserved as notified by NLDC/RLDC. Only downward revision is restricted for units that had a schedule below the minimum turndown level since the SCUC run would consider such schedules, and any further reduction may disturb such SCUC run. An Illustration has been included in this Statement of Reasons under reasons provided for draft **Regulation 46 (4) (d).**

29.3.2. With regard to suggestions of PCKL and KSEBL, it is clarified that downward revision is permitted from stations where the schedule is above the Minimum Turndown level.

29.3.3. With regard to suggestions of PSPCL and MPPMCL to revise the timeline, it has been clarified that the timeline, has been kept such that the SCUC run is completed by 1500 hrs, enabling ample time for units under warm/hot start to start the next day, if required.

29.3.4. Regulation 46 (4) (b) of the 2023 Grid Code Regulations has been modified as follows:

"(b) Beneficiaries of such stations, whose units are likely to be scheduled below minimum turndown level for some or all time blocks of the D day, shall be permitted to revise their requisitions from such stations by <u>1430</u> Hrs of D-1 day, in order to enable such units to be on bar. The revised requisition from the said generating stations, once confirmed by the beneficiaries by <u>1430</u> Hrs of D-1 day, shall be final and binding after <u>1430</u> Hrs of D-1 day and further reduction in drawal schedule shall not be allowed from such stations <u>except in cases when the generating stations remain above minimum turn-down level</u>."

30. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (d))

30.1. **Commission's Proposal**

30.1.1. The Commission had proposed the following in Regulation 46 (4) (d) of the Draft Regulations:

"(d) If the NLDC in coordination with RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i) extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security; (iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of clause 4 of this Regulation, so as to bring such units to their minimum turndown level, in order to maximize availability of on-bar units, by 1800 Hrs. of D-1 day and update the list on the respective RLDC website."

30.2. **Comments have been received from PTC**

30.2.1. **PTC** has suggested that NLDC should be allowed to schedule incremental energy above the minimum turndown level.

30.3. **Analysis and Decision**

30.3.1. With regard to suggestions of PTC, it is clarified that from the units committed under SCUC, NLDC may keep some quantum or full quantum upto the DC of the station as reserved which may be scheduled by NLDC in case of reserve dispatch requirement arising in the grid. The quantum not kept reserved by NLDC above the minimum turndown level, would be available for beneficiaries under rescheduling or sale of power by generator in the market. Once the unit is committed under SCUC, the schedules upto the Minimum turndown level can also be utilised by the beneficiaries for giving schedules upto the gate closure, since such schedules shall get finalised when the SCED is run prior to dispatch.

For Illustration, suppose A generating station ‘G’ has a DC of 1000 MW with a Minimum turndown level of 550 MW. Suppose the schedule for ‘G’ at 1430 hrs PM on ‘D-1’ day is 400 MW. NLDC decided to commit ‘G’ under SCUC. This implies the schedule of ‘G” would be given as 550 MW minimum, however such schedule shall take effect on ‘D’ day when SCED is run after clearance of RTM. However, once a unit is committed under SCUC, beneficiaries can give up a schedule in ‘G’ upto its DC minus the quantum kept as reserved by NLDC. However, the beneficiaries who gave the schedule of 400 MW cannot give downward revision of the schedule in a unit committed under SCUC since NLDC has committed it. It is also clarified that in case ‘G’ is scheduled for 800 MW on ‘D-1’ day by way of up revision of schedule given by beneficiaries, beneficiaries can exercise downward revision of schedule upto 550 MW on ‘D-1’ day or ‘D’ day.

30.3.2. Regulation 46 (4) (d) of the 2023 Grid Code Regulations has been modified as follows:

“(d) If the NLDC in coordination with the RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i) extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security; (iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of this clause , so as to bring such units to their minimum turndown level in order to maximize availability of on-bar units, by 1500 Hrs. of D-1 day and update the list on the respective RLDC website:

Provided that in respect of such generating station or unit thereof which has been brought to its minimum turndown level by the NLDC under this clause, downward revision by the beneficiary shall not be allowed.”

31. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (f))

31.1. **Commission’s Proposal**

31.1.1. The Commission had proposed the following in Regulation 46 (4) (f) of the Draft Regulations:

“(f) The generating station from which incremental energy has been scheduled as per sub-clause (d) of clause 4 of this Regulation shall be paid from the Deviation and Ancillary Services Pool Account, for the energy charge equivalent to the incremental energy

scheduled, and the generating station from which reduction in generation has been directed as per sub-clause (e) of clause (4) of this Regulation shall pay back to the Deviation and Ancillary Services Pool Account, the energy charge equivalent to the decremental energy."

31.2. **Comments have been received from PTC and SRPC**

31.2.1. **SRPC** has sought clarity on compensation due to part load operation and unit shut down charges after SCUC or revival after SCUC may be brought out.

31.3. **Analysis and Decision**

31.3.1. The suggestions of SRPC to incorporate a provision for compensation due to part load operation to be inserted in the clause have been accepted. The draft regulation has been modified as 46 (4) (g) in the 2023 Grid Code Regulations as follows:

"(g) The generating station from which incremental energy has been scheduled as per sub-clause (d) of this clause shall be paid from the Deviation and Ancillary Services Pool Account, for the energy charge equivalent to the incremental energy scheduled, and the generating station from which reduction in generation has been directed as per sub-clause (f) of this clause shall pay back to the Deviation and Ancillary Services Pool Account, the energy charge equivalent to the decremental energy. <u>Compensation for part load operation of a generating station or unit thereof brought on bar under SCUC shall be paid from the Deviation and Ancillary Services Pool Account</u>."

32. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (g))

32.1. **Commission's Proposal**

32.1.1. The Commission had proposed the following in Regulation 46 (4) (g) of the Draft Regulations:

"(g) The URS power over and above the minimum turn down level, available in the generating station or unit thereof, brought on-bar under clause 4(d) of this Regulation shall be deemed to be available for use as SRAS or TRAS or both in terms of the Ancillary Services Regulations."

32.2. **Comments have been received from Tata Power.**

32.2.1 Tata **Power – TPDDL** has commented that the Distribution utility shall have its right to recall URS power whenever needed in six-time blocks based on its utilization. The same should not be considered solely for the purpose of utilization under SRAS or TRAS. The generating station selected under SCUC, is a deemed provider of SRAS and TRAS. Will a generator chosen under SCUC be permitted to sell its power in excess of minimum turndown level in the exchange or the excess power shall remain committed for secondary/Tertiary ancillary services? If they are not allowed to sell the excess power and are required to remain available for TRAS, will they be paid the commitment charges as per the ancillary services regulations.

32.3. **Analysis and Decision**

32.3.1. The instant clause has been modified, and "after declaration of RTM results" has been inserted, thereby clarifying that under the instant clause, only the URS left over after RTM is being considered. Further, regarding the clarification sought for power above the Minimum Turndown level for units under SCUC, it is clarified that a specified quantum above the Minimum Turndown level may be kept as reserve by NLDC. Any power beyond such specified quantum reserved shall be available for rescheduling by beneficiary or sale by generating station. A new clause as Regulation 46(4)(e) of Grid Code Regulations 2023 has been added, which is as follows:

> *"(e)The NLDC shall indicate the quantum of URS power to be kept as reserves, in the generation station or unit thereof brought under SCUC, and such quantum of power identified as reserves shall not be available for scheduling by the beneficiary or for sale by the generating station through the energy market. The quantum of power over and above the identified quantum of reserves may be rescheduled by the beneficiary(ies) or scheduled by way of selling in the market."*

32.3.2. The Commission has proposed the provision of SCUC to be undertaken on a day ahead basis in respect of the regional entity generating stations or units thereof, for which tariffs are determined under section 62 of the Act. This proposition is duly incorporated in Regulation 46(4) of the Grid Code Regulations, 2023. However, upon analysing the data provided by POSOCO, the Commission has noted that there are some generating units with a cold start up time exceeding 24 hours. Therefore, it is not feasible to commit such units which have a higher cold start up time on a day ahead basis under SCUC. On the other hand, these units can serve as a valuable resource in cases of inadequate reserves under certain circumstances and may be considered for SCUC if reasonable time is allowed, taking their start-up time into account. In light of this, the Commission has decided that in case NLDC anticipates based on assessment that adequate reserves may not be available on D-1 Day or D-day either under day ahead SCUC or under Ancillary Services Regulations, it may also carry out SCUC three (3) days in advance of the actual day of scheduling for the regional entity generating stations. Accordingly, the Commission has introduced a new provision for SCUC three days in advance under certain circumstances, which are added as Regulation 46(5) of the Grid Code Regulations, 2023.

32.3.3. The draft regulation has been modified as 46 (4) (h) in the 2023 Grid Code Regulations as follows:

"(h) The URS power over and above the minimum turn down level, available <u>after declaration of RTM results</u>, in the generating station or unit thereof, brought on-bar under sub-clause (d) of this clause shall be deemed to be available for use as SRAS or TRAS or both in terms of the Ancillary Services Regulations"

33. Security Constrained Unit Commitment (SCUC) (Regulation 46 (4) (h))

33.1. Commission's Proposal

33.1.1. The Commission had proposed the following in Regulation 46 (4) (h) of the Draft Regulations:

"(h) UNIT SHUT DOWN (USD)

(i) The generating stations or units thereof, identified by NLDC in co-ordination with RLDCs, as per Clause (4) (c) of Regulation 46 of these regulations, but not brought on bar under SCUC, shall have the option to operate at a level below the minimum turn down level or to go under Unit Shut Down (USD).

(ii) In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD, by entering into a contract(s) covered under the Power Market Regulation or by arranging supply from any other generating station or unit thereof owned by such generating company subject to honouring of rights of the original beneficiaries of the said generating station or unit thereof from which supply is arranged."

33.2. **Comments have been received from KSEBL, KPTCL, Tata Power, MSEDCL, NTPC, GRIDCO, Dhariwal, Torrent Power and POSOCO.**

33.2.1. **KSEBL and KPTCL** have suggested that the already in place RSD procedure may be invoked. Hence, other mechanism with commercial implications is not needed. In this case, if any unit/ generator goes under shutdown the beneficiary may be given an option to whether it requires power through the alternate source before the generator finalises procurement through alternate source, if cheaper power is available with SLDC in real time, opportunity to schedule the same may be given to SLDC's.

33.2.2. **Tata Power** has suggested that following provision may be incorporated:

> *"Further, if the generator goes under shutdown and the replacement power scheduled by it which is purchased from power market and scheduled to the beneficiaries is cheaper than the variable cost of the Generator, the gains realized from the same after accounting all the associated expenses shall be shared with the respective beneficiary in 50:50 or any other ratio decided by the Commission."*

Tata Power commented that this regulation is a welcome step as the generators will be liable to supply the power requisitioned by the DISCOM corresponding to its requisition before the generators going under USD.

33.2.3. **Tata Power – MPL** has suggested that this clause shall expose the generator to a higher risk of buying power from the market and scheduling it to beneficiaries, without any fault of the generator. IEGC 4th amendment provides for startup fuel cost if the number of start/stops per year is greater than 7. However, the current draft grid code does not provide for any such compensation due to USD. The generator running below MTL should be compensated for the degradation of performance parameters.

33.2.4. **NTPC** has commented that the Generator must not be liable to supply power in case of USD, which is due to unreasonable requisitions given by beneficiaries not meeting the minimum technical loading/requirements of generating units thus leading to Reserve Shutdown/Unit Shutdown of the units and also incurring extra operational expenses. Instead, the generator is required to get compensated for extra operational expenses owing to USD. Detailed procedure for USD and then bringing of unit thereof with consideration of start-up time of Units and compensation mechanism need to be formulated in line with existing RSD procedure.

33.2.5. **MSEDCL** has suggested that to maintain flexibility to the buyer, generators having PPA with DISCOMs shall not be allowed to bid theier power in the day-ahead market without the consent of the buyer. This would enable DISCOMs to schedule power from these generators if there is an unexpected increase in demand. However, they can be allowed to bid in the RTM market. Beneficiaries should be allowed to revise the schedule of the ISGS station subject to the Technical Minimum of that plant. Any buyer should be allowed to take responsibility for the TM schedule of the unit (scheduling

URS/Off-Bar power), provided other beneficiaries will not take undue advantage of market rates during the evening peak. URS power available can be scheduled by the beneficiaries as per the current practice of revising the schedule from 7th and 8th block onwards. NLDC can use SRAS and TRAS by scheduling it from 4th time block.

33.2.6. **GRIDCO** has suggested that in the event of a non-supply of power to the beneficiaries under unit shut down (USD), a mechanism for compensation to the affected beneficiaries may be suitably prescribed in the Grid Code**.**

33.2.7. **Dhariwal** has suggested that the commercial settlements during USD should be clearly stipulated in the final IEGC 2022.

33.2.8. **Torrent Power** has suggested that in a Forced Outage, the generating company is unable to fulfil its obligation to supply electricity to its beneficiaries, and in turn, the generating company may have the option to supply to make alternate arrangements so as to ensure the reliability of supply. Hence, it is may be clarified that the same is available only in case of 'forced outage' in the proposed draft.

33.2.9. **POSOCO** has suggested that new provisions (iii) and (iv) may be incorporated as below:

> *"(iii) Once a unit is taken under shutdown, it can be recalled any time after 8 hours. In case of system requirements, the generating unit can be revived before 8 hours as per the instructions of RLDC. Provided that the time to start a machine under different conditions such as HOT, WARM and COLD shall not be more than 4 hours, 8 hours and 12 hours respectively. Time taken to revive the unit from shutdown shall be counted from the time of intimation given by RLDC to concerned generating station. RLDC may advise the generating station to revive the unit in advance (more than specified time to revive the unit).*
>
> *(v) In case the machine is not revived as per the revival time declared by the generating station or the time given by the RLDC for different types of machine to start, the machine shall be treated under outage for the duration starting from the likely revival time and actual revival time upto DC during such duration shall be considered as zero. Provided that the decision to revive the unit shall be as per the SCUC analysis."*

33.2.10. **NTPC** has commented that the Commission may provide enabling provisions on the revised "Scheme for Flexibility in Generation and Scheduling of Thermal/ Hydro Power Stations through bundling with Renewable Energy and Storage Power". The indicative clause is as follows:

> *"any thermal/hydro generating station operating under the flexibility scheme can replace the costlier power with the cheaper RE power by scheduling such RE power within the GNA quantum of thermal/hydro generator."*

33.3. **Analysis and Decision**

33.3.1. Some of the stakeholders have suggested retaining the existing RSD procedure. However, in the proposed draft, in the interest of the beneficiaries, the Commission has taken that view that the generating company has to fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD as specified in the regulations. The relevant extract of the Explanatory Memorandum to the Draft Grid Code Regulations 2022 is as follows:

> ***"8.5(i) Unit Shut Down (USD)***
>
> *As per the provisions under the 2010 Grid Code, a generating station can opt for reserve shutdown if it doesn't get sufficient requisition upto its technical minimum*

level. However, this may deprive those beneficiaries who have requisitioned power from such generating station.

We observe that once a generating station has declared DC for which it is entitled for fixed cost, it cannot deprive beneficiary from availing such power. Hence, in order to honor the rights of the original beneficiaries of such generating station, it has been proposed that such generator may decide not to go under USD and generate power , may sell surplus power under power market as per provisions of PPA and Grid Code or if it decides to go under USD it may supply power to beneficiaries who have requisitioned schedule, from other generating stations through any contracts allowed under the PMR Regulations to meet its supply obligation towards its original beneficiaries. Accordingly the term "Reserve shutdown" has been done away with and have been replaced as proposed "unit shutdown" mechanism."

33.3.2. As regards the suggestion of Tata Power for sharing the profit, the Commission observes that the generator has to fulfil its supply obligation by arranging supply through the methods mentioned in this regulation. While arranging the power, the cost of arranging such power may be cheaper or costlier than the variable cost of the generator. Accordingly, a case may be made out that if gains are shared, losses should also be shared. Since, in the instant case, the beneficiary would be making payment as per energy charge rate, with power being made available to such beneficiary which it scheduled, beneficiaries' interests are protected, and hence, sharing is not provided for.

33.3.3. With regard to suggestions of MSEDCL that URS power should be allowed to be scheduled by the beneficiaries as per the current practice of revising the schedule from the 7th and 8th block onwards, it is clarified that the 2023 Grid Code permits such revision subject to certain conditions under SCUC.

33.3.4. With regard to Tata Power-MPL suggestions regarding compensation for start-up, the 2023 Grid Code has saved the provisions applicable under the 2010 Grid Code for compensation till the mechanism is specified separately.

33.3.5. With regard to suggestions of NTPC to include a Detailed procedure for USD and consideration of the start-up time of Units, it is clarified that the same has been accepted and inserted under this Regulation. Further with regard to other suggestions of NTPC, a detailed regulation for arranging alternate supply by generating station including under USD has been provided for as Regulation 48.

33.3.6. The suggestions of GRIDCO for compensation in the event of non-supply of power to the beneficiaries under unit shut down (USD), are not accepted.

33.3.7. As regards the suggestion of POSOCO, the new clauses have been incorporated as Regulations 47(3) and 47(4) of the Grid Code Regulations, 2023.

33.3.8. As regards clarification sought by Torrent Power for the provision of a supply obligation only in case of 'forced outage', it is clarified that the instant clause is not for 'Forced outage' but for 'USD' which is a planned shutdown necessitated due to schedules below Minimum turndown level.

33.3.9. The comments of NTPC to consider "Scheme for Flexibility in Generation and Scheduling of Thermal/ Hydro Power Stations through bundling with Renewable Energy and Storage Power" have been accepted. Accordingly, Regulation 48 provides that "a generating station other than REGS replacing its scheduled generation by power supplied from REGS irrespective of whether such identified sources are located within or outside the premises of the generating station or at a different location" with an elaborate Regulation 48(3) detailing the methodology of such replacement.

33.3.10. The draft regulation has been modified as 47 in the 2023 Grid Code Regulations as follows,

"47. UNIT SHUT DOWN (USD)

(1) The generating stations or units thereof, identified by NLDC in co-ordination with RLDCs, as per sub-clause (c) of clause (4) of Regulation 46 of these regulations, but not brought on bar under SCUC, shall have the option to operate at a level below the minimum turn down level or to go under Unit Shut Down (USD).

(2) In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD, by arranging supply either (a) by entering into a contract(s) covered under the Power Market Regulation; or (b) by arranging supply from any other generating station or unit thereof owned by such generating company subject to honouring of rights of the original beneficiaries of the said generating station or unit thereof from which supply is arranged; or (c) through SCED subject to the stipulation under sub-clause (a)(vi) of clause (2) of Regulation 49 of these regulations, the details of which shall be provided in the Detailed Procedure to be specified by NLDC in this regard.

(3) In case of emergency conditions, for reasons of grid security, a generating station or unit thereof, which is under USD may be directed by NLDC to come on bar, and in such event the generating station or unit thereof shall come on bar under hot, warm and cold conditions as per the time period to be specified in the detailed procedure under sub clause (i) of clause (4) of Regulation 46 of these regulations.

(4) Once a generating station is brought on bar as per clause (3) of this Regulation, it shall be treated as a unit under SCUC and scheduled and compensated as per Regulation 46 of these regulations."

34. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (a) (i))

34.1. Commission's Proposal

34.1.1. The Commission had proposed the following in Regulation 47 (1) (a) (i) of the Draft Regulations:

"(1) The following scheduling related activities shall be carried out on daily basis for regional entities, on day ahead basis, 'D-1' day, for supply of power on 'D' day, as follows:

(a) Declaration of Declared Capacity by generating stations:

(i) The generating station based on coal and lignite shall submit the following information for 00000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day,:

(a) Time block-wise On-bar Declared Capacity (MW) for on-bar units;

(b) Time block-wise Off-bar Declared Capacity (MW) for off-bar units;

(c) Time block-wise Ramp up rate (MW/min) for on-bar capacity;

(d) Time block-wise Ramp down rate (MW/min) for on-bar capacity;

(e) MWh capability for the day;

(f) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar;"

34.2. **Comments have been received from IEX, PTC**

34.2.1. **IEX** has suggested that the Draft IEGC has provided that all the scheduling under GNA and T-GNA shall take place on a day ahead basis providing the flexibility to the buyers to procure power across different contracts and utilize their transmission access. In this context, attention is drawn to the short-term contracts executed in the Term Ahead Market of the Power Exchanges. The Commission vide Order dated 07.06.2022 has approved Daily, Weekly, Monthly, and Day Single Sided Contracts up to 3 months. As per the aforesaid Order these contracts cannot be annulled or curtailed in any manner other than transmission system constraints or force majeure condition validated by the concerned system operator. Some of the points where clarity is required: **-**

- Is the Generator required to declare the capacity for the short-term contracts also? - If a Discom is a seller, will it have to declare the capacity similar to the Generating Stations provided under the Regulations?
- Whether an embedded intra-state entity has to apply for T-GNA (both for bilateral and collective transactions) when capacity under GNA is available for the State?
- How will the power exchange provide the schedule for the contracts entered in its platform to the SLDC to be incorporated in the requisition for the intra-state entities to schedule in GNA and T-GNA transactions?

IEX has requested to clarify the above through illustrations in SoR, which can also be incorporated in the Procedure.

34.2.2. **PTC** has suggested that the Time block-wise Ramp up rate, Ramp-down rate, and minimum turndown level may not be declared daily as these parameters remain the same on a rolling basis. After giving these values initially, the only declaration may be provided whenever there is a change in the value of these parameters from their initially declared values.

34.3. **Analysis and Decision**

34.3.1. With regard to suggestions of PTC, necessary provision may be made in software to take default values in case of no change.

34.3.2. With regard to various clarifications sought by IEX, the following may be noted:

i. The contract under said Order dated 7.6.2022 is a bilateral contract that the buyer may schedule under GNA or T-GNA. The buyer needs to adhere to terms of contract with regard to revision , annulment etc.

ii. Each generating station including the one which enters into the contract referred to in Order dated 7.6.2022 is required to declare its DC on the day ahead basis. This helps system operator assess overall capacity available in the system.

iii. A distribution company is not required to provide declared capacity.

iv. An embedded intra-State buyer that does not have any GNA or T-GNA, may schedule its power under GNA of the State with arrangement with the State. It may obtain a separate T-GNA to get its power scheduled.

v. Once a bilateral contract is entered into, normally the buyer schedules it under GNA or T-GNA.

34.3.3. The draft regulation has been retained and renumbered as 49 (1) (a) (i) in the 2023 Grid Code Regulations.

35. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (a) (ii))

35.1. **Commission's Proposal**

35.1.1. The Commission had proposed the following in Regulation 47 (1) (a) (ii) of the Draft Regulations:

"(ii) The generating station based on hydro energy shall submit the following information for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day:
(a) Time block-wise ex-bus declared capacity;
(b) MWh capability for the day;
(c) Ex-bus peaking capability in MW and MWh;
(d) Time block-wise Ramp up rate (MW/min) for on-bar capacity;
(e) Time block-wise Ramp down rate (MW/min) for on-bar capacity;
(f) Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity;
(g) Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations."

35.2. **Comments have been received from SJVN, NHPC, Tata Power and POSOCO**

35.2.1. SJVN and **NHPC** suggested that the data required at points (d), (e) and (f) are generally fixed for hydro generators and are declared during COD and need not r be declared daily.

35.2.2. **Tata Power** has requested clarification on the forbidden zones for HYDRO Units.

35.2.3. **POSOCO** has suggested that in case of less water is available and the plant is not able to generate as per installed capacity in that case unit wise maximum and along with probable combination of unit maximum may be provided.

35.3. **Analysis and Decision**

35.3.1. With regard to suggestion of SJVN and NHPC, it is clarified that option of default rates may be included in software. However, if some generating station wishes to submit the details, the same is required to be built into the Regulations.

35.3.2. The operation of hydro generating unit at a point, which lies within the forbidden zones of that hydro generating unit, should be avoided due to concerns with vibration and cavitation. Accordingly, the generator is allowed to run either below the forbidden zone or above the forbidden zone. Therefore, it is essential to specify the unit-wise forbidden zones in MW and % of ex-bus installed capacity.

35.3.3. The suggestion of POSOCO has been accepted.

35.3.4. The draft regulation has been modified as 49 (1) (a) (ii) in the 2023 Grid Code Regulations and inserted an additional clause (h) in the regulation as follows:

"(h) <u>Unit wise maximum MW along with probable combination of unit maximum in case adequate water is not available</u>."

36. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (a) (iii))

36.1. **Commission's Proposal**

36.1.1. The Commission had proposed the following in Regulation 47 (1) (a) (iii) of the

Draft Regulations:

"(iii) The generating station based on gas or combined cycle generating station shall submit the following for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day:
(a) Time block-wise On-bar Declared Capacity (DC) for the station in MW separately for each fuel such as domestic gas, RLNG or liquid fuel and On-bar units;
(b) Time block wise Off-bar Declared Capacity (MW) and off-bar units;
(c) MWh capability for the next day;
(d) Time block wise Ramp up rate (MW/min) for on-bar capacity;
(e) Time block wise Ramp down rate (MW/min) for on-bar capacity;
(f) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar."

36.2. **Comments have been received from SRPC, Torrent Power and POSOCO**

36.2.1. **SRPC** has suggested that a new provision (g) may be inserted as below:

"(g) Time for revival of unit (s) under USD (synchronization and reaching Minimum turndown level)"

36.2.2. **Torrent Power** has suggested that the words "*separately for each fuel such as domestic gas, RLNG or liquid fuel and On-bar units"* may be deleted from the clause as declaring DC for each fuel type would indirectly reveal the source availability and commercials for that particular entity. It is humbly submitted that commercial information of any organisation is bound by the terms of confidentiality.

36.2.3. **POSOCO** has suggested that bifurcation of DC for Combined cycle and Open cycle may be included. This may help the beneficiary to requisition.

POSOCO has also suggested the following modifications:

"(c) MWh capability <u>(fuel wise) in different modes of operation</u> for the next day;

36.3. **Analysis and Decision**

36.3.1. With regard to SRPC's suggestions a separate procedure with details of start-up time has been included in the 2023 Grid Code.

36.3.2. With regard to suggestions of Torrent Power, it is clarified that DC fuel-wise is required so that beneficiaries can place requests for schedule accordingly.

36.3.3. The suggestions of POSOCO have been accepted.

36.3.4. The draft regulation has been modified as 49 (1) (a) (iii) in the 2023 Grid Code Regulations as follows:

"(c) MWh capability <u>(fuel-wise</u>) for the next day;"

37. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (a) (iv))

37.1. **Commission's Proposal**

37.1.1. The Commission had proposed the following in Regulation 47 (1) (a) (iv) of the Draft Regulations:

"(iv) The renewable energy generating station, individually or represented by a lead generator or QCA, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time block for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day."

37.2. **Comments have been received from POSOCO**

37.2.1. **POSOCO** has suggested that AVC may also be submitted source wise apart from aggregate AVC.

37.3. **Analysis and Decision**

37.3.1. The suggestions of POSOCO have been accepted. The draft regulation has been modified as 49 (1) (a) (iv) in the 2023 Grid Code Regulations as follows,

"(iv) The regional entity renewable energy generating station, individually or represented by a lead generator or QCA, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract wise breakup for each time block for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day. <u>The source wise breakup of aggregate available capacity of the pooled generation shall also be furnished</u>."

38. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (a) (v))

38.1. **Commission's Proposal**

38.1.1. The Commission had proposed the following in Regulation 47 (1) (a) (v) of the Draft Regulations:

"(v) ESS including pumped storage plant, individually or represented by lead ESS or QCA on their behalf, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time-block for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day."

38.2. **Comments have been received from Greenko and POSOCO**

38.2.1. **Greenko** has commented that a pumped storage plant, having multiple reversible pumped-turbine coupled with motor-generator units, aggregate charging and discharging schedule for each time block should not be linked to any particular unit to serve contract with beneficiaries.

38.2.2. **POSOCO** has suggested that ESS shall telemeter the State of Charge to RLDC. In the case of pump storage plants, the water level shall be telemetered in up reservoir and down reservoir to RLDCs.

38.3. **Analysis and Decision**

38.3.1. With regard to suggestions of Greenko, it is clarified that it is the prerogative of ESS to enter into a type of contract with buyers/sellers. The Regulations does not provide any linking to a particular unit and shall be governed as per the contract.

38.3.2. The suggestions of POSOCO are a matter of detailing and may be included in appropriate Procedure.

38.3.3. The draft regulation has been retained and renumbered as 49 (1) (a) (v) in the 2023 Grid Code Regulations.

39. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (b) (i))

39.1. **Commission's Proposal**

39.1.1. The Commission had proposed the following in Regulation 47 (1) (b) (i) of the Draft Regulations:

"(b) Entitlement of each beneficiary or buyer:

(i) For generating station, where Central Government has allocated power, each State shall be entitled to a MW despatch up to the State's Share in the station's declared capacity for the day. Accordingly, based on declared capacity of such generating station, RLDC shall declare entitled share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day"

39.2. **Comments have been received from NTPC**

39.2.1. **NTPC** has suggested that, since allocations of MoP are based on the Installed Capacity of the Station, it is submitted that the entitlements should be calculated based on the station's declared capacity for the day plus the quantum of untied/surrendered power.

39.3. **Analysis and Decision**

39.3.1. With regard to suggestions of NTPC, it is clarified that while declaring entitlement, RLDC shall consider the allocation of power by the Government of India and other required parameters. The draft regulation has been modified as 49 (1) (b) (i) in the 2023 Grid Code Regulations as follows:

"(b) Entitlement of each beneficiary or buyer:

(i) For generating station, where the Central Government has allocated power, each State shall be entitled to a MW despatch up to the State's Share in the station's declared capacity <u>(including On-bar Declared Capacity and Off-bar Declared Capacity)</u> for the day. Accordingly, based on declared capacity of such generating station, RLDC shall declare entitled share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day."

40. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (b) (ii))

40.1. **Commission's Proposal**

40.1.1. The Commission had proposed the following in Regulation 47 (1) (b) (ii) of the Draft Regulations:

"(ii) The generating station other than those having allocation of power by the Central Government shall indicate the declared capacity along with respective share of the beneficiary(ies) or buyers in accordance with the contracts entered with them. Based on declared capacity of such generating station and share of the beneficiaries or buyers as indicated by such generating station, RLDC shall declare share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day."

40.2. **Comments have been received from SRPC, Torrent Power and ReNew Power**

40.2.1. **SRPC** has suggested that the declared capacity may be modified based on their contract.

40.2.2. **Torrent Power** has suggested that the words "Based on declared capacity of such generating station and share of the beneficiaries or buyers as indicated by such generating station, RLDC shall declare share of each beneficiary or buyer" may be deleted.

40.2.3. **Renew Power** has requested for clarification that since Pro-rata scheduling is not mandatory in this case, can a generator choose to offer more power to a particular beneficiary as per at its own discretion?

40.3. **Analysis and Decision**

40.3.1. With regard to suggestions of SRPC, Torrent Power and Renew Power, it is clarified that share of beneficiary is declared by RLDC only in cases where the Government of India issues allocation of power. The allocation of power for a generating station other than those having allocation of power by the Central Government, shall be governed in accordance with the contract entered between such generator and its beneficiary(ies)/buyer(s).

40.3.2. The draft regulation has been retained and renumbered as 49 (1) (b) (ii) in the 2023 Grid Code Regulations.

41. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47(1)(c))

41.1. Commission's Proposal

41.1.1. The Commission had proposed the following in Regulation 47 (1) (c) of the Draft Regulations:

"(c) The requisition for scheduling of intra-State entities shall be as submitted by the regional entity buyers and regional entity sellers in accordance with the contracts entered between them."

41.2. Comments have been received from POSOCO

41.2.1. **POSOCO** has suggested that the clause may be modified as below:

"(c) The <u>mutually agreed</u> requisition for scheduling of intra-State entities shall be as submitted by the regional entity buyers <u>or</u> regional entity sellers in accordance with the contracts entered between them."

41.3. Analysis and Decision

41.3.1. The suggestions of POSOCO have been accepted. The draft regulation has been modified as 49 (1) (c) in the 2023 Grid Code Regulations as follows,

"(c) The <u>mutually agreed</u> requisition for scheduling of intra-State entities shall be as submitted by the regional entity buyers or regional entity sellers in accordance with the contracts entered between them by 7 AM on 'D-1' day."

42. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47(1)(d))

42.1. Commission's Proposal

42.1.1. The Commission had proposed the following in Regulation 47 (1) (d) of the Draft Regulations:

"(d) The requisition for cross-border schedule along with its breakup from various sources shall be submitted by Settlement Nodal Agency (SNA) for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day;"

42.2. Comments have been received from NVVN and POSOCO

42.2.1. **NVVN** has suggested that the scheduling requisitions for cross border supply are submitted by LTA/MTOA allottees individually (now converted to GNA) to RLDC and RLDC compiles and prepares the above schedule and sends the combined schedule for cross border entity. NVVN has requested that the same process continues after the Grid Code amendment.

42.2.2. **POSOCO** suggested that the timeline may be revised to 8 AM.

42.3. **Analysis and Decision**

42.3.1. As suggested by POSOCO, the timeline has been revised to 8 AM.

42.3.2. Suggestions of NVVN about submission of schedules by LTA/MTOA allottees are not accepted since the role of SNA as provided in CERC (Cross Border Trade of Electricity) regulations, 2019 is as follows:

"25. Scheduling

….

(2) The selling entity or the buying entity, as the case may be, shall inform their requisitions to the Settlement Nodal Agency in accordance with the procedure specified as per Part - 6 on Scheduling and Despatch Code of Grid Code.

(3) Settlement Nodal Agency shall co-ordinate with System Operators of respective neighbouring countries for scheduling of cross border transactions and revisions during the day of operation."

As per above SNA needs to coordinate for cross border transactions.

42.3.3. The draft regulation has been modified as 49 (1) (d) in the 2023 Grid Code Regulations as follows:

"(d) The requisition for cross-border schedule along with its breakup from various sources shall be submitted by the Settlement Nodal Agency (SNA) for 0000 hours to 2400 hours of the 'D' day, by 8 AM on 'D-1' day;"

43. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (e))

43.1. **Commission's Proposal**

43.1.1. The Commission had proposed the following in Regulation 47 (1) (e) of the Draft Regulations:

"(e) Requisition of schedule by buyers who are GNA grantees:

(i) Based on the entitlement declared in accordance with sub-clause (b) of clause (1) of Regulation 47 of these regulations, SLDC on behalf of intra-State entities which are drawee GNA grantees, shall furnish time block-wise requisition for drawal to concerned RLDC in accordance with the contracts, by 8 AM of 'D-1' day.

(ii) Other drawee GNA grantees who are regional entities shall furnish time block-wise requisition for drawal to the concerned RLDC in accordance with contracts, by 8 AM of 'D-1' day.

(iii) The SLDC on behalf of the intra-State entities which are drawee GNA grantees, as well as other drawee GNA grantees while furnishing time block-wise requisition under this Regulation shall duly factor in merit order of the generating stations with which it has entered into contract(s):

Provided that the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order."

43.2. **Comments have been received from AP Transco, HVPNL, KPTCL, Tata Power, Enel, WIPPA, Renew, Hero Future Energy, National Solar Federation, Greenko, O2 Power and TS Transco.**

43.2.1. **AP Transco** has suggested that in the name of IEGC revision, NLDC is restricting beneficiaries to schedule power before one day and sixteen hours, i.e., by D-1 day 8 AM. Even though the generator is ready to accept the revised schedule and the beneficiary state is required to revise the schedule for grid security and the economy of the system, then what is the necessity to restrict the revision by NLDC. It is reducing flexibility in the system and causing deterioration in system security, economy and despatch of VRE generation.

43.2.2. **HVPNL** has suggested that, as per the new draft regulation, NRLDC's scheduling and dispatch instructions will be in line with the Northern Regional Grid requirement, whereas the power schedules and despatch must only be as per the requirement of partner states viz. States of Punjab, Haryana, Himachal Pradesh and UT Chandigarh.

43.2.3. **KPTCL** has suggested that either the Economic operation or Must Run word may be dropped from Regulation as both cannot happen simultaneously. The Economic operation and Must Run words are contradictory to each other. During solar hours, 70-100% of State demand is met by Renewable energy, and during the monsoon period most of the days, the State meets the entire demand from RE sources. During such instances, the State is keeping the lowest cost generation sources under off/minimum conditions in order to honour the Must Run Status stipulated in the Regulation.

43.2.4. **Tata Power, Enel, WIPPA, Renew, Hero Future Energy, National Solar Federation** and **Greenko** have requested to retain regulation 5.2 (u) of the existing IEGC, as it supports the RE generators in reducing the curtailment drastically. The Stakeholders have requested the following modification in the clause,

"Wind, solar, wind-solar hybrid with or without storage, standalone storage drawing power from renewable energy sources and hydro power plant (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and should not be subjected to curtailment due to merit order despatch as well as due to any commercial consideration.

In the event of transmission constraint or system security constraint renewable energy generation may be curtailed after harnessing flexible resources including energy storage systems.

In the event of extreme circumstances, when MUST RUN plant has to be curtailed, the details shall be published on the RLDC/SLDC website the following day, as the case may be, giving the date, name of RE generation plant, installed capacity, curtailment quantum in MWh, duration of curtailment and reasons thereof."

43.2.5. **O2 Power** has suggested that renewable energy generating stations shall be treated as MUST RUN power plants and should not be subjected to curtailment due to merit order despatch or any commercial consideration.

43.2.6. **TS Transco** has suggested that the existing clause of Special Dispensation of RE Generation may be continued.

43.3. **Analysis and Decision**

43.3.1. With regard to comments of AP Transco, it is clarified that schedule revisions have been retained in the 2023 Grid Code from the $7^{th}/8^{th}$ time block subject to specified conditions.

43.3.2. With regard to suggestions of HVPNL, it is clarified that scheduling is strictly as per schedule requisition by drawee entities.

43.3.3. With regard to suggestions of stakeholders to continue with must run status of renewable energy generating stations, it is clarified that the instant regulation already provides that “renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order”. However, with large integration of RE, there may be a situation that the entire demand is met through RE, still, some tied up RE generating station cannot be given schedule due to variation in demand (low demand). In such a situation ‘MUST RUN’ would mean under drawal by the beneficiary, which may lead to grid issues. Accordingly, it has been provided that “*the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order*”.

43.3.4. With regard to suggestions of KPTCL about economic operation and scheduling RE, it is clarified that economic operation is subject to additional conditions of scheduling RE first to ensure that the green objectives of the Government of India are fulfilled.

43.3.5. The draft regulation has been modified as 49 (1) (f) in the 2023 Grid Code Regulations as follows:

“(f) Requisition of schedule by the buyers which are GNA grantees:
(i) Based on the entitlement declared in accordance with sub-clause (b) of clause (1) of this Regulation, SLDC on behalf of the intra-State entities which are drawee GNA grantees, shall furnish time block-wise requisition for drawal to the concerned RLDC in accordance with the contracts, by 8 AM of ‘D-1’ day.
(ii) Other drawee GNA grantees which are regional entities shall furnish time block-wise requisition for drawal to the concerned RLDC in accordance with contracts, by 8 AM of ‘D-1’ day.
(iii) The SLDC on behalf of the intra-State entities which are drawee GNA grantees, as well as other drawee GNA grantees while furnishing time block-wise requisition under this Regulation shall subject to technical constraints, duly factor in merit order of the generating stations with which it has entered into contract(s):
Provided that the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order.”

44. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (f) (iii))

44.1. Commission’s Proposal

44.1.1. The Commission had proposed the following in Regulation 47 (1) (f) (iii) of the Draft Regulations:

“(iii) RLDC shall issue final drawal schedules for GNA grantees by 9 AM on ‘D-1’ day.”

44.2. Comments have been received from POSOCO

44.2.1. **POSOCO** has suggested in case the requisition is not revised by the GNA grantees, the RLDCs shall curtail the schedule on a pro-rata basis. The sequence of curtailment is defined in this case. Further, within a span of 15 minutes or a short duration, it may be difficult to adhere to the revised regulation or curtailment due to added complexity in types of transactions like RE or non-RE.

44.3. **Analysis and Decision**

44.3.1. The Commission has noted the suggestion of the stakeholder and observes that as per Regulation 49 (1) (g) (ii) read with Regulation 49 (1) (g) (i) of these regulations, the drawee GNA grantees shall revise their requisition for drawal schedule based on the availability of transmission corridors for such grantee. This is a mandatory provision and the Commission is of the view that the grantee has to ensure its compliance in order to avoid any undesired curtailment of schedule by RLDC based on its prudence. However, in case the drawee grantees do not communicate the revised requisition, RLDC may revise the schedules on a pro-rata basis or such basis as provided in the Detailed procedure.

44.3.2. The Commission has modified the Draft regulation to incorporate the injection schedule so that the entire injection and drawl schedule as at 9 AM is communicated.

44.3.3. The draft regulation has been modified as 49 (1) (g) (iii) in the 2023 Grid Code Regulations as follows,

"(iii) RLDC shall issue final drawl schedules <u>and injection schedules for drawee and injecting</u> GNA grantees by 9 AM on 'D-1' day."

45. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (i))

45.1. **Commission's Proposal**

45.1.1. The Commission had proposed the following in Regulation 47 (1) (i) of the Draft Regulations:

"(i) The generating station whose tariff is determined under Section 62 of the Act, may sell its unrequisitioned surplus as available at 10 AM in the day ahead market."

45.2. **Comments have been received from PTC, MSEDCL, UPSLDC, Dhariwal, MPPMCL, TS Transco and POSOCO**

45.2.1. **PTC** has suggested that no prior consent of buyers/beneficiaries shall be required for selling of un-requisitioned surplus (URS) has not been mentioned in the clause. So, the same may be clarified.

45.2.2. **MSEDCL** has requested that the URS power should be made available to the Discoms to meet its contingency requirements, and if at all such power is to be sold by Generators in the market, such sale should be subject to the consent of the Discoms.

45.2.3. **UPSLDC** has requested to retain the existing provision, as Clause 47(1) (i) of draft IEGC has revoked the beneficiary's right to seek its consent for selling power of its share in DAM, which the beneficiary won't be able to call back if as and when it needs after 10 AM.

45.2.4. **Dhariwal** has suggested that the said provision for selling un-requisitioned surplus should only be allowed to all generating companies under Section 62 or section 63 of the Act only in Real time market.

45.2.5. **MPPMCL** has requested the clause to be removed. According to the draft Regulation, Generator can sell its unrequisitioned surplus in the day-ahead market. Because of this mechanism, if any real-time variation in demand occurs, drawl entities will not have any choice but to schedule their power, and this will lead to scheduling of the higher VC power. The mechanism for profit sharing by selling power by the generator in the Day-ahead market is also not defined.

45.2.6. **TS Transco** has suggested that as per the existing Regulation i.e. the Generator may sell power from the share of its original beneficiaries in the day-ahead Market with the consent of such beneficiaries; and in the real-time market without the requirement of consent from the beneficiaries, before the trading for the real time market for a specified duration commences. In both cases, the realized gains shall be shared between the ISGS and the concerned beneficiaries in the ratio of 50:50, in the billing of the following month.

45.2.7. **POSOCO** has suggested that the clause may be modified as below:

"(i) The generating station whose tariff is determined under Section 62 of the Act as well as other generating station, may sell its unrequisitioned surplus as available at 10 AM in the day ahead market."

POSOCO has commented that at present a Section 62 power plant can participate in the day ahead market after taking consent from the beneficiary who has not requisitioned or requisitioned less power than its entitlement. The power sold is not available for the concerned beneficiary to requisition from their said plant. Clarification may be given on such consent is required or not.

45.3. **Analysis and Decision**

45.3.1. Most of the stakeholders have suggested retaining the provision seeking the consent of the beneficiary prior to selling un-requisitioned surplus power in the day ahead market and also suggested that a mechanism for profit-sharing in case the generator sells such power may be devised. This Regulation has been proposed keeping in view that a good amount of power remains un-requisitioned even though grid is facing shortage of power. The Commission is of the view that the beneficiary has the full right corresponding to its share of power in a generating station up to 9.45 AM, by that time it is expected that all beneficiaries should firm up their requisition, and the generating station, whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus power available at 9.45 AM in the day ahead market, unless the consent is withheld by the beneficiary or buyer in writing.

45.3.2. It is also noted that the Commission subsequently vide its Order no.14/SM/2023 dated 29.9.2023 has provided the following:

"Issue No. 7: Consent to a generator for scheduling in the Day Ahead Market:

35. Grid-India has submitted that as per the Grid Code under Regulation 49(1)(l), there is a provision to withhold the consent to the generating stations under section 62 for selling the un-requisitioned power in day ahead market. It is stated that it is contrary to Rule 9 of the LPSC Rules 2022. Necessary clarification is required in this regard.

36. Sub-clause (l) of Clause of Regulation 49 of Grid Code provides as under:
"(l) The generating station whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus as available at 9.45 AM in the day ahead market, unless the consent is withheld by the beneficiary or buyer in writing. The sharing of net savings shall be as per provisions of Tariff Regulations and until a provision is made in the Tariff Regulations, in accordance with the detailed procedure to be prepared by NLDC and approved by the Commission."

37. Rule 9 of Electricity (Late Payment Surcharge and Related Matters) Rules 2022 provides as under:

"Power not requisitioned by a distribution licensee

1) *A distribution licensee shall intimate its schedule for requisitioning power for each day from each generating company with which it has an agreement for purchase of power at last two hours before the end of the time for placing proposals or bids in the day ahead market for that day, failing which generating company may sell the unrequisitioned power in the power exchange.*

38. Considering the above-quoted clauses, rules and suggestions of Grid- India, we are of the view that the generating station whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus as available at 9.45 AM in the day ahead market, without the consent of the beneficiary(ies)."

45.3.3. With regard to suggestions for the sharing of gains, a provision have been inserted that the sharing of net savings shall be as per the provisions of Tariff Regulations. In the absence of a provision in the Tariff Regulations, the sharing shall be done in accordance with the detailed procedure to be prepared by NLDC and approved by the Commission.

45.3.4. With regard to the suggestion of selling un-requisitioned surplus power by the generating stations covered under section 63 of the Act, the Commission acknowledges that the mechanism for profit sharing of such generating stations is governed by the contracts entered into between the generating stations and their buyers.

45.3.5. The draft regulation has been modified as 49 (1) (l) in the 2023 Grid Code Regulations as follows:

"(l) The generating station whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus as available at 9.45 AM in the day ahead market, unless the consent is withheld by the beneficiary or buyer in writing. The sharing of net savings shall be as per provisions of Tariff Regulations and until a provision is made in the Tariff Regulations, in accordance with the detailed procedure to be prepared by NLDC and approved by the Commission."

46. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (j))

46.1. **Commission's Proposal**

46.1.1. The Commission had proposed the following in Regulation 47 (1) (j) of the Draft Regulations:

"(j) Scheduling of collective transactions:

(i) Power Exchange(s) shall open bidding window for day ahead collective transactions from 10 AM to 11.30 AM of 'D-1' day.

(ii) The power exchange shall submit the day-ahead provisional trade schedules along with net power interchange of each bid area and region to NLDC by 12.00 Noon of 'D-1' day.

(iii) NLDC shall validate the same from system security angle and inform the power exchange with revisions required, if any, due to transmission congestion or any other system constraint by 12.30 PM of 'D-1' day.

(iv) The power exchange shall submit the final trade schedules to NLDC for regional entities and to SLDC for intra-State entities by 1.00 PM of 'D-1' day."

46.2. **Comments have been received from KPTCL, CPPA and Jindal India TPL**

46.2.1. **KPTCL, PCKL, CPPA** & **Jindal India TPL** have suggested that the time may be considered as 10 AM to 12:00 PM. Reducing time for open bidding window will impact the bidding process and create false demand.

46.2.2. **CPPA** has commented that the proposed new bidding time line in Day ahead market will reduce the Gate closure time by Half an Hour (30 Minutes). This will be inadequate for Planning and submitting bids with large portfolios.

46.3. **Analysis and Decision**

46.3.1. The bidding timeline has been reduced to ensure that other steps are accommodated and the timeline to run SCUC is finished by 1500 hrs giving adequate time to start-up warm/hot condition generating stations.

46.3.2. The draft regulation has been modified as 49 (1) (m) in the 2023 Grid Code Regulations as follows:

"(m) Scheduling of collective transactions:
(i) Power Exchange(s) shall open bidding window for day ahead collective transactions and TRAS from 10.00 AM to 11AM of 'D-1' day.
(ii) The power exchange shall submit the day-ahead provisional trade schedules along with net power interchange of each bid area and region to NLDC by 11.45 AM of 'D-1' day.
(iii) NLDC shall validate the same from system security angle and inform the power exchange with revisions required, if any, due to transmission congestion or any other system constraint by 12.15 PM of 'D-1' day.
(iv) The power exchange shall submit the final trade schedules to NLDC for regional entities and to SLDC for intra-State entities by 1.00 PM of 'D-1' day."

47. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (n))

47.1. **Commission's Proposal**

47.1.1. The Commission had proposed the following in Regulation 47 (1) (n) of the Draft Regulations:

"(n) Procedure for scheduling of transaction in Real-time market (RTM)
(i) All the entities participating in the real-time market may place their bids and offers on the Power Exchange(s) for purchase and sale of power.
(ii) The window for trade in real-time market for day (D) shall open from 22.45 hrs to 23.00 hrs of (D-1) for the delivery of power for the first two time-blocks of 1st hour of day (D) i.e., 00.00 hrs to 00.30 hrs, and will be repeated every half an hour thereafter.
(iii) NLDC shall indicate to t0he Power Exchange(s) the available margin on each of the transmission corridors before the gate closure.
(iv) The power exchanges shall clear the real-time bids from 23.00 hrs till 23.15 hrs of 'D-1' day based on the available transmission corridor and the buy and sell bids for the real time market (RTM) for the specified duration.
(v) The cleared bids shall be submitted by the Power Exchanges to the NLDC for scheduling. The NLDC shall announce the final schedule by 23.45 hrs of 'D-1' day and communicate to the RLDCs to prepare the schedule for despatch."

47.2. **Comments have been received from NTPC and POSOCO**

47.2.1. **NTPC** has suggested that the Final dispatch schedule after the finalization of

RTM /SCED/AS should be available to the generator at least two clear time blocks before the actual dispatch of generation. NTPC has suggested a modification in the clause, "The NLDC shall announce the final schedule by <u>23.30 hrs of 'D-1' day</u> and communicate to the RLDCs to prepare the schedule for despatch."

47.2.2. **POSOCO** has suggested that due to multiple power exchanges further direction is required on the methodology for providing the available margin to each power exchanges. Since for processing the RTM, the time available is less, providing a common margin to all power exchange may create issue of overscheduling of power in a corridor.

POSOCO has also suggested an insertion in clause (iv),
"…specified duration <u>and inform the same to NLDC by 23:15</u>"

47.3. **Analysis and Decision**

47.3.1. The suggestion of NTPC to intimate schedule by 23.30 hrs is not accepted since some time is required after NLDC announces the final schedule by 23.30 hrs.

47.3.2. The suggestions of POSOCO to provide a methodology for providing available margin to each power exchange is already provided for in Regulation 44(2)(g) of the 2023 Grid Code. Further the suggestion to include 23:15 for communication by exchanges have been accepted and inserted in the clause.

47.3.3. The draft regulation has been modified as 49 (1) (q) in the 2023 Grid Code Regulations as follows:

"(q) Procedure for scheduling of transaction in Real-time market (RTM):
(i) All the entities participating in the real-time market including TRAS may place their bids and offers on the Power Exchange(s) for purchase and sale of power.
(ii) The window for trade in real-time market for day (D) shall open from 22.45 hrs to 23.00 hrs of (D-1) for the delivery of power for the first two time-blocks of 1st hour of day (D) i.e., 00.00 hrs to 00.30 hrs, and will be repeated every half an hour thereafter.
(iii) NLDC shall indicate to the Power Exchange(s) the available margin on each of the transmission corridors before the gate closure.
(iv) The power exchanges shall clear the real-time bids from 23.00 hrs till 23.15 hrs of 'D-1' day based on the available transmission corridor and the buy and sell bids for the real time market (RTM) for the specified duration and intimate the cleared bids to NLDC by 23.15 hrs, for scheduling."

48. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (1) (o))

48.1. **Commission's Proposal**

48.1.1. The Commission had proposed the following in Regulation 47 (1) (o) of the Draft Regulations:

"(o) Issuance of day-ahead schedule:
RLDC shall convey the following for the next day to all regional and other entities involved in inter-state transactions after each step of finalisation of schedules for GNA grantees and T-GNA grantees:
(i) The ex-power plant schedule to each of the regional entity generating station, in MW for different time blocks along with breakup of schedule for each beneficiary or buyer.
(ii) The "net drawal schedule" for each regional entity in MW for each time block.

(iii) All requisitions and schedules shall be rounded off to the nearest two decimals at each control area boundary for each of the transaction and shall have a resolution of 0.01 MW."

48.2. **Comments have been received from NHPC and POSOCO**

48.2.1. **NHPC** has suggested that the regulation does not provide the time by which RLDC shall issue the final day ahead schedule. Hence, NHPC has proposed that final schedule shall be issued by 23:00 Hrs of D-1 day.

48.2.2. **POSOCO** has suggested that Clause (i) & (ii) may be modified as below:

"(i) …beneficiary or buyer, <u>market sale/purchase etc.</u>

(ii)…each time block <u>along with breakup of schedule from each Regional entity, market sale/purchase etc.</u>"

48.3. **Analysis and Decision**

48.3.1. The Commission has noted the suggestions of the stakeholders

48.3.2. The suggestions of POSOCO have been accepted, and the Draft Regulation has been modified so as to convey the details by RLDC while issuing a "net drawal schedule" such as break-up of schedule from each of the sellers, schedule of injection to ISTS and injection or drawal schedule under collective transactions.

48.3.3. With regard to suggestion of NHPC, it is clarified that the schedules are required to be issued after each step of finalisation of schedules for GNA grantees and T-GNA grantees and accordingly a specific time is not provided for.

48.3.4. The draft regulation has been modified as 49 (1) (t) in the 2023 Grid Code Regulations as follows,

"(t) Issuance of day-ahead schedule:

RLDC shall convey the following for the next day to all regional and other entities involved in inter-state transactions after each step of finalisation of schedules for GNA grantees and T-GNA grantees:

(i) The ex-power plant schedule to each of the regional entity generating station, in MW for different time blocks along with breakup of schedule for each beneficiary or buyer.

(ii) The "net drawal schedule" for each regional entity in MW for each time block, along with break-up of (a) schedule from each of the sellers, (b) schedule of injection to ISTS and (c) injection or drawal schedule under collective transaction

(iii) All requisitions and schedules shall be rounded off to the nearest two decimals at each control area boundary for each of the transaction and shall have a resolution of 0.01 MW."

49. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (2) (a) (iii))

49.1. **Commission's Proposal**

49.1.1. The Commission had proposed the following in Regulation 47 (2) (a) (iii) of the Draft Regulations:

"(2) Additional factors to be considered while finalising schedule
(a) Security Constrained Economic Despatch (SCED)

(iii) The generating stations, including those for which the tariff is determined by the Commission under Section 62 of the Act, willing to participate in SCED shall declare at their discretion, the variable charges upfront to NLDC on weekly basis after factoring in likely changes in fuel cost and part load compensation, if any.”

49.2. **Comments have been received from Dhariwal and POSOCO**

49.2.1. **Dhariwal** and **POSOCO** have suggested that the said provision for participation under SCED shall also be allowed to generating companies under Section 63 of the Act.

49.3. **Analysis and Decision**

49.3.1. The suggestions of Dhariwal and POSOCO to include generating stations other than under Section 62 have been accepted and included in Regulation 49(2)(a)(iii). It has also been provided that generating stations under Section 62 shall declare energy charges and those other than Section 62 would declare SCED compensation charges. The SCED compensation charges may be declared after factoring in the likely changes in fuel cost and part load compensation, if any. For generating stations under Section 62, a separate provision for part load compensation on account of SCED has been included as Regulation 49(2)(a)(v) as follows:

> *“(v)Part load compensation for reduction in schedule on account of SCED, in respect of a generating station or unit thereof whose tariff is determined under Section 62 of the Act shall be paid from the savings in the SCED Account. Part load compensation for reduction in schedule of a generating station or unit thereof other than those whose tariffs are determined under Section 62 of the Act shall be factored in by such generating station while declaring the SCED Compensation Charge and shall not be paid separately.”*

49.3.2. The draft regulation has been modified as 49 (2) (a) (iii) in the 2023 Grid Code Regulations as follows:

“(iii) The generating stations which are willing to participate in SCED shall declare the energy charge, <u>or the SCED Compensation Charge (after factoring in the likely changes in fuel cost and part load compensation, if any</u>), as applicable, to NLDC on weekly basis.”

50. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (2) (a) (vi))

51. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (2) (a) (ix))

51.1. **Commission’s Proposal**

51.1.1. The Commission had proposed the following in Regulation 47 (2) (a) (ix) of the Draft Regulations:

“(ix) The net saving to the generating stations shall be shared between the beneficiaries or buyers and the generating stations as per the prevailing Tariff Regulations in respect of the generating stations whose tariff is determined by the Commission under Section 62 of the Act and in respect of other generating stations as per the terms of the contracts with their respective buyers or beneficiaries.”

51.2. **Comments have been received from BYPL and POSOCO**

51.2.1. **BYPL** has suggested that a provision may be considered to net-off the savings with the charges for the scheduled energy that buyers or beneficiaries have to pay.

51.2.2. **POSOCO** has suggested that it may be difficult to implement the calculation of net benefit considering each plant under Tariff Regulations or contracts and it may be kept in line with SCED current order.

51.3. **Analysis and Decision**

51.3.1. With regard to suggestions of BYPL, it is clarified that SCED accounts are issued separately from REA accounts and, hence, net off is not recommended. Further, a portion of savings is shared with generating stations since they are required to schedule up or schedule down within the next 15 min-30 min. Hence the suggestions of BYPL are not accepted.

51.3.2. Considering suggestions of POSOCO, the regulation has been modified to include the provision that net savings shall be as per the detailed procedure to be prepared by NLDC.

51.3.3. The draft regulation has been modified as 49 (2) (a) (x) in the 2023 Grid Code Regulations as follows:

"(x) For any increment in the generation schedule on account of SCED, the participating generator shall be paid from the 'SCED Account' at the rate of its energy charge or SCED Compensation Charge declared upfront by the generator. For any decrement in the generation schedule on account of SCED, the participating generator shall pay to the 'SCED Account' at the rate of energy charge or SCED Compensation Charge, as applicable.

<u>The net saving to the generating stations shall be shared between the beneficiaries or buyers and the generating stations as per the detailed Procedure to be prepared by NLDC within two months of the notification of these regulations after stakeholder consultation and seeking approval of the Commission</u>."

52. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (2) (b))

52.1. **Commission's Proposal**

52.1.1. The Commission had proposed the following in Regulation 47 (2) (b) of the Draft Regulations:

"(b) Margins for primary response:
For the purpose of ensuring primary response, RLDCs and SLDCs, as the case may be, shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units, whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.
In case of gas or liquid fuel-based units, suitable adjustment in Installed Capacity should be made by RLDCs and SLDCs, as the case may be, for scheduling in due consideration the prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:
Provided that the hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods to avoid spillage:"

52.2. **Comments have been received from OTPC, Torrent Power**

52.2.1. **OTPC** has suggested that Palatana cannot avoid operating a Steam Turbine in VWO due to the reliability of the steam turbine. However, all the PFR requirements will be met by Gas turbine and Steam turbine.

52.2.2. **Torrent Power** has suggested that all the costs associated with keeping margin for primary response may be directly borne by the respective RLDC/SLDC. This cost, in turn, would be passed on to all the concerned stakeholders through the applicable tariff exercises.

52.3. **Analysis and Decision**

52.3.1. With regard to the exemption sought by OTPC, it is clarified that a specific exemption may be taken by moving the appropriate application with details of technical difficulty.

52.3.2. With regard to comments of Torrent Power, it is clarified that providing primary response is a mandatory requirement as per the CEA Standards and the 2023 Grid Code and must be adhered to. The commercial mechanism for providing such response has been brought in Tariff Regulations for specified generating stations.

52.3.3. The draft regulation has been modified as 49 (2) (b) in the 2023 Grid Code Regulations as follows:

"(b) Margins for primary response:
For the purpose of ensuring primary response, RLDCs and SLDCs, as the case may be, shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units, whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.
In case of gas or liquid fuel-based units, suitable adjustment in Installed Capacity shall be made by RLDCs and SLDCs, as the case may be, for scheduling in due consideration the prevailing ambient conditions of temperature and pressure vis à- vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:
Provided that the hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity or any other overload capability as allowed under sub-clause (a) of clause (10) of Regulation 45 of these regulations, during high inflow periods to avoid spillage:"

53. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (3) (a))

53.1. **Commission's Proposal**

53.1.1. The Commission had proposed the following in Regulation 47 (3) (a) of the Draft Regulations:

"(3) Power to revise schedules:
(a) Curtailment of Scheduled transactions for grid security
When for the reason of transmission constraints or in the interest of grid security, it becomes inevitable to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed by the Regional Load Despatch Centre (keeping in view the transaction which is likely to relieve the threat to grid security) as follows:
(i) Transactions under T-GNA shall be curtailed first followed by transactions under GNA.

(ii) Transactions under T- GNA shall be curtailed in the following order:
(a) Within transactions under T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market;
(b) Within bilateral transactions under T-GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage), pro rata based on their T-GNA quantum;
(c) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on T-GNA, after curtailment of generation from other sources, within T-GNA.
(d) Collective transactions under day ahead market shall be curtailed after curtailment of bilateral transactions under T-GNA.
(e) Collective transactions under real time market shall be curtailed after curtailment of collective transactions under day ahead market.
(iii) Transactions under GNA shall be curtailed in the following order:
(a) Within transactions under GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage), on pro rata basis based on their GNA quantum.
(b) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on their GNA quantum, after curtailment of generation from other sources, within GNA.
(iv) RLDC or SLDC, as the case may be, shall publish a report of such incidents on its website."

53.2. **Comments have been received from IWPA, Enel, Tata Power, Greenko, Renew, National Solar Federation, WIPPA, Hero Future Energy, Sembcorp, TS Transco and POSOCO**

53.2.1. **IWPA** has commented that,

(i) The existing must run Regulation may be restored and added to the new IEGC.

(ii) The captive generators may be placed in the bottom most category for the purpose of curtailment priority in the draft Regulation 47.

(iii) Although the word "grid security" has not been defined elaborately in the draft Regulation, the Hon'ble APTEL has clearly defined some critical conditions that cannot be construed as grid security issues. The conditions have to be incorporated in Regulation 47 so as to avoid misusing of "grid security" conditions by SLDCs and curtail RE power.

53.2.2. **Enel, Tata Power, Greenko, Renew, National Solar Federation, WIPPA** and **Hero Future Energy** have requested that a deemed generation status/ compensation mechanism be allowed for curtailing wind, solar and wind solar hybrid energy as such generators are losing revenue under such events.

53.2.3. **Sembcorp** has suggested modification in the clause,

> *"Provided that, appropriate Commission shall publish detailed guidelines for management of RE curtailment after notification of this Grid Code. Also, the details and required data for establishing the need for curtailment shall be provided by Regional Load Despatch Centre to the stakeholders.*
>
> *Provided further that till such time the appropriate Commission makes guidelines*

for management of RE curtailment, the guidelines notified by the Central Commission shall prevail.”

53.2.4. **TS Transco** has suggested that under T-GNA, there may be GNA power scheduled. In GNA quantum, bilateral and collective power can also be scheduled. In such cases the clarification on curtailment priority may be issued.

53.2.5. **POSOCO** has suggested that the current IEGC allows the curtailment w.e.f. from the 4th time block, so the Commission may allow similar provisions.

53.3. **Analysis and Decision**

53.3.1. With regard to suggestions of IWPA to retain must run status for wind and solar generating stations, it is clarified that Regulation 49(1)(f)(iii) provides as follows:

> *“(iii) The SLDC on behalf of the intra-State entities which are drawee GNA grantees, as well as other drawee GNA grantees while furnishing time block-wise requisition under this Regulation shall subject to technical constraints, duly factor in merit order of the generating stations with which it has entered into contract(s):*
>
> *<u>Provided that the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order</u>.”*

As per above, it is mandated that renewable energy generating stations shall be scheduled first. Further, the Commission is of the view that the safety and security of grid operation in view of the large integration of renewable energy sources (RES) to the grid needs to be looked into. The Commission is aware of the fact that with more and more penetration of renewable energy generation in the grid, it becomes difficult to manage the grid the way it was operated when the integration of RES to the grid was in a nascent stage. As per the monthly report of “All India Installed Capacity (in MW) of Power Stations” published by CEA for the month of June, 2023, the installed capacity of RES (excluding hydro) is around 30.72% (129642.55 MW) of the total installed capacity (421901.63 MW) as on 30.6.2023. In view of the large integration of RES to the grid, which is envisaged to further increase at a faster pace in the near future, it is practically not feasible to grant the must run status to the RES. It is important to note that during a day time when the RE generation is at its peak, in order to extract maximum generation from RES, all other sources of energy generation may be at a lower operating point of generation possibly at their technical minimum and leave little scope for further reduction of generation from such non-RES on the ground of technical feasibility. With due considerations of all factors in order to facilitate integration of RES while protecting the safety and security of the grid, the Commission has decided the curtailment priority on transactions under T-GNA and GNA. In each category, the curtailment from the RES is the last leg of curtailment for the reason of transmission constraint or in the interest to grid security. Even in the existing Grid Code Regulations 2010, solar and wind power has been treated as a must-run station subject to grid security or the safety of any equipment or personnel is not endangered.

53.3.2. With regard to suggestions of IWPA to include details of ‘grid security’ under which curtailment may take place, a new sub-clause (B) have been inserted under the Regulation where it is provided that NLDC shall publish the operational limits of parameters.

53.3.3. The suggestions of IWPA to keep curtailment for captive generator at last is not accepted.

53.3.4. A number of stakeholders have suggested that the curtailed generation based on RE may be considered as deemed generation and compensated to the generator by its procurer at PPA tariff. It is clarified that the same shall be as per contracts entered into between seller and buyer.

53.3.5. With regard to suggestions of POSOCO to allow curtailment w.e.f. the 4th time block, it is clarified that the revision of schedules under the 2023 Grid Code is from the 7th/8th time block, which shall also be applicable for curtailment.

53.3.6. With regard to suggestions of Sembcorp regarding guidelines to be issued for RE curtailment, it is clarified that the Forum of regulators have already issued such Guidelines in November 2022 namely "Model Guidelines for Management of RE Curtailment for Wind and Solar Generation" in accordance with APTEL Order dated 02-08-2021, in the Appeal No 197 of 2019 & IA No. 1706 of 2019.

53.3.7. With regard to clarifications sought by TS Transco regarding curtailment priority under T-GNA and GNA transactions, it is clarified that under the GNA Regulations and the 2023 Grid Code, it is the prerogative of a buyer to decide which contract to schedule under GNA or which contract under T-GNA. A buyer may decide to schedule a long term contract under T-GNA and a short term contract under GNA. While curtailment under this Regulation, the length of the contract would not decide the priority. A transaction, whether under a short term contract, if scheduled under GNA would be curtailed after a transaction under T-GNA (even if under long term contract).

53.3.8. The draft regulation has been modified as 49 (3) (a) in the 2023 Grid Code Regulations as follows:

"(3) Power to revise schedules:
(a) Curtailment of scheduled transactions for grid security:
(A) When for the reason of transmission constraints or in the interest of grid security, it becomes inevitable to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed <u>with immediate effect</u> by the Regional Load Despatch Centre (keeping in view the transaction which is likely to relieve the threat to grid security) as follows:
(i) Transactions under T-GNA shall be curtailed first followed by transactions under GNA.
(ii) Transactions under T- GNA shall be curtailed in the following order:
(I) Within transactions under T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market;
(II) Within bilateral transactions under T-GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage), pro rata based on their T-GNA quantum;
(III) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on T-GNA, after curtailment of generation from other sources, within T-GNA.
(IV) Collective transactions under day ahead market shall be curtailed after curtailment of bilateral transactions under T-GNA.
(V) Collective transactions under real time market shall be curtailed after curtailment of collective transactions under day ahead market.
(iii) Transactions under GNA shall be curtailed in the following order:
(I) Within transactions under GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with up to three

hours pondage (in case of excess water leading to spillage), on pro rata basis based on their GNA quantum.
(II) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on their GNA quantum, after curtailment of generation from other sources, within GNA.
(iv) RLDC or SLDC, as the case may be, shall publish a report of such incidents on its website.
<u>(B) NLDC shall publish, from time to time on its website, the operational limits of parameters for maintenance of grid security for the information and compliance of users of the grid. The curtailment of schedule shall be carried out only in case violation of the operational limits</u>."

54. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (3) (b))

54.1. **Commission's Proposal**

54.1.1. The Commission had proposed the following in Regulation 47 (3) (b) of the Draft Regulations:

"(b) In the event of bottleneck in evacuation of power due to outage, failure or limitation in the transmission system or any other constraint necessitating reduction in generation, the RLDC shall revise the schedules.

Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective from 7th block or 8th block depending on time block in which schedule has been revised as first-time block."

54.2. **Comments have been received from SRPC, SJVN, PTC, NHPC and POSOCO**

54.2.1. **SRPC** has suggested that the Proviso to the clause may be modified as below: "… become effective <u>in the block specified by RLDC and maximum upto from 7th block or 8th block</u> depending on time block ….**"**

SRPC also commented that the System may already be under alert or emergency schedule and allowing injection and drawl for 1.5 hrs may be a threat to system security.

54.2.2. **SJVN** has suggested that the scheduled generation of the ISGS shall be revised to be equal to the actual generation till normalization of the Grid Conditions to avoid heavy penalties on Generator.

54.2.3. **PTC** has suggested that since the schedule can be revised only for the 7th /8th time-block, the schedule in the first to the sixth time-block shall be deemed to be revised to actual generation so that a heavier penalty to the seller due to variation in the schedule as per extant DSM regulations can be avoided.

54.2.4. **NHPC** has suggested that the regulation will lead to additional DSM penalties to the generators up to the 7th or 8th time block. This DSM penalty to the generator is not correct as tripping of transmission is not under the control of generators. Therefore, it is proposed that this clause be reviewed as under:

> *"(b) The revision in schedule shall become effective from the 7th/8th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first to seventh/eighth time blocks of such an event, the scheduled generation of the ISGS shall be deemed to have been*

revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised accordingly."

54.2.5. **POSOCO** has suggested that the actuals may be replaced for the first 6/7-time blocks to be mentioned. The schedule shall be deemed to have been revised equal to actual. Tripping due to activation of SPS may be also be added.

54.3. **Analysis and Decision**

54.3.1. With regard to suggestions of SRPC to revise schedules before the 7th/8th time block, it is clarified that any injecting entity or drawing entity may need some time to adjust to the revised schedule, and the same has been provided as the 7th/8th time block. Suppose the schedule of a drawing entity is revised from the next time block, such drawing entity may keep drawing as per its unrevised schedule due to no time margin. Hence unless extreme emergency, time is required before schedule revision takes effect. The suggestions to revise schedules for the first six or seven blocks with the actuals, as applicable, are not accepted keeping in view the observations made above. However, the commercial modalities for DSM liability in case of a forced outage or partial outage of a generating station may be addressed through DSM regulations.

54.3.2. The provision as proposed in the Draft Regulations has been retained.

55. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (4) (a))

55.1. **Commission's Proposal**

55.1.1. The Commission had proposed the following in Regulation 47 (4) (a) of the Draft Regulations:

"(a) SLDCS, regional entity generating stations, regional entity ESSs, beneficiaries, buyers or cross-border entities may revise their schedules under GNA as per clause (b) and clause (c) of this Regulation in accordance with their respective contracts.

Provided that scheduled transactions under T-GNA once scheduled cannot be revised other than in case of forced outage as per clause (7) of Regulation 47 of these regulations."

55.2. **Comments have been received from ReNew Power and CPPA**

55.2.1. **Renew Power** has suggested the modification and addition of new provisions in the clause:

"Provided that scheduled transactions under T-GNA, <u>other than that of REGS and RHGS</u>, once scheduled cannot be revised other than in case of forced outage as per clause (7) of Regulation 47 of these regulations.

<u>Further provided that, in order to manage under/over injection, REGS and RHGS may revise their T-GNA bilateral transactions (excluding collective transactions in day ahead market and real time market through power exchange) as per clause (c) of this Regulation or may sell/procure power by entering into a contract, which includes contracts covered under Power Market Regulation, as well as bilateral contracts outside power exchange</u>."

ReNew Power has commented that unlike conventional generating stations, generation in REGS/RHGS is not under the control of developer but is highly weather dependent.

55.2.2. **CPPA** and **RIL** (during the public hearing) suggested that Clause 47.4 (a) implies that revision under T-GNA is not allowed once its scheduled.

CPPA has commented that as per the CERC, GNA and Connectivity Regulation 2022, T-GNA is specified as application for any period from 1 time block and up to 11 months. Hence, its necessary to continue existing provisions for the revision of FCFS and Advance application.

55.3. **Analysis and Decision**

55.3.1. It is important to note that in the proposed regulatory framework, the revision of the schedule is based on the request of the buyers. The clause under discussion pertains to the regional entity buyers, and therefore, in order to bring clarity to this regulation, the title of clause 4 of Regulation 49 of these regulations has been modified as "*4) Revision of schedules on request of buyers which are GNA grantees:"*

55.3.2. With regard to suggestions of Renew Power to allow the REGS and RHGS to revise their schedule under T-GNA bilateral transactions (excluding collective transactions in day ahead market and real time market through power exchange), it is clarified that the same is already included under Regulation 49(8) of 2023 Grid Code reproduced as follows:

> *"(8) In case of requirement of revision of schedule due to forecasting error, a WS seller may revise its schedule only in case of bilateral transactions and not in case of collective transaction. Such revision of schedule shall become effective from the time block and in the manner as specified in sub-clause (c) of clause (4) of this Regulation."*

Further clarifications were issued vide 14/SM/2023 dated 29.9.2023 as follows:

> *"30. We observe that the WS seller is allowed to revise its schedule in case of bilateral transactions, due to forecasting errors. The same has been provided to take care of the intermittent nature of renewable sources which a generating station may not be able to forecast accurately. The generating stations are required to have GNA for the quantum for which its power is to be scheduled as per the Grid Code. However, there may be conditions where GNA has been granted but has not become effective, due to which power scheduled by such generating station may be under "deemed T-GNA". We observe that there are four cases of scheduling among seller and buyer as follows:*

Cases	Generating station under:	Buyer schedules power of generating station under:
1	GNA	GNA
2	Deemed T-GNA	GNA
3	GNA	T-GNA
4	Deemed T-GNA	T-GNA

As per above in Case 1, there is no confusion in the revision of the schedule by generating station. However, for Cases 2,3 and 4, there is a need for clarity on the revision of the schedule by the WS seller or ROR generating station due to forecasting error. We are of the considered view that the generating station which is WS seller or ROR shall be able to revise its schedule which shall be applicable from the 7th/8th time block, as applicable. This is irrespective of whether such a generating station is under GNA or deemed T-GNA. i.e. for cases, 2,3,4 generating station which is the WS seller or ROR shall be able to revise its schedule under Regulation 49(8) and 49(9) of the Grid Code in case of bilateral transactions."

55.3.3. With regard to suggestions of CPP, it is clarified that under 'Advance T-GNA' schedules are provided only on a day ahead basis. Once schedules are finalised, they cannot be changed under T-GNA. Hence, there is a flexibility until day ahead.

55.3.4. The draft regulation has been modified as 49 (4) (a) in the 2023 Grid Code Regulations as follows:

"(4) Revision of schedules on request of <u>buyers which are GNA grantees</u>:

(a) SLDCs <u>on behalf of intra-state entities</u>, regional entity ESSs <u>as drawee entities</u>, beneficiaries, <u>regional entity</u> buyers or cross-border buying entities may revise their schedules under GNA as per sub-clauses (b) and (c) of this clause in accordance with their respective contracts:

Provided that scheduled transactions under T-GNA once scheduled cannot be revised other than in case of forced outage as per clause (7) of this Regulation."

56. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (4) (b) (i))

56.1. Commission's Proposal

56.1.1. The Commission had proposed the following in Regulation 47 (4) (b) (i) of the Draft Regulations:

"(b) The request for revision of scheduled transaction for 'D' day, shall be allowed to be made in any time block starting 2 PM on 'D-1' day subject to the following:
(i) In respect of a generating stations whose tariff is determined under Section 62 of the Act, upward revision of schedule shall be allowed starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un-requisitioned surplus after finalization of schedules under day ahead market."

56.2. Comments have been received from KPTCL, ReNew Power, MSEDCL and TS Transco

56.2.1. **KPTCL** has suggested including downward/upward revisions of the schedules which shall become effective from the 4th time block in real time.

56.2.2. **Renew Power** has suggested that the clause may be applicable for Generating stations except for REGS/RHGS.

56.2.3. **MSEDCL** has commented that in the existing IEGC, a similar provision for sale of URS power is available subject to the consent of the beneficiary. The proposed proviso is doing away with the requirement of the consent of the beneficiary which inter-alia means that the Discoms/Beneficiaries will not be able to recall such power if such power has been sold in the DAM by the Generators. Further, the provision does not envisage any waiver of fixed charge liability. In such case, the beneficiary will not be able to avail the benefit of the Generation if it doesn't schedule the power within the stipulated time, despite the payment of fixed charges by the beneficiary.

56.2.4. **TS Transco** has suggested the right to revision of schedules of long term/medium term contracts entered by beneficiaries during the day ahead and in Real Time with the 7/8 Time Block notice as per control area requirement should be continued, as the beneficiaries have valid contracts and paying fixed charges.

56.3. **Analysis and Decision**

56.3.1. As per regulation 49(1)(l) of these regulations, the un-requisitioned surplus as available at 9.45 AM in the generating station whose tariff is determined under Section 62 of the Act, may be released in the day ahead market. Such URS power may have been sold by the generating station in DAM. Hence any upward revision by the buyer/beneficiary in such generating stations can be allowed only after the day ahead market results are finalised. The power sold in DAM cannot be called back by the beneficiary since it is already sold. As a result, the buyer/beneficiary has been allowed any upward revision of schedule starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un-requisitioned surplus in such generating stations, after finalization of schedules under the day ahead market.

56.3.2. However, the above restriction is not applicable when the buyer/beneficiary is doing a downward revision of scheduling subject to conditions laid down in SCUC. Accordingly, considering the suggestions of KPTCL to include clarity on a downward revision of the schedule, a new clause related to a downward revision of the schedule has been added as Regulation 49(4)(b)(ii) of these regulations.

56.3.3. With regard to suggestions of Renew Power for REGS/RHGS, it is clarified that sub-clause (iii) of clause (b) of this Regulation provides as follows:

> *"(iii) Request of buyers for upward or downward revision of schedule in respect of the generating stations other than those whose tariff is determined under Section 62 of the Act, shall be allowed in terms of provisions of the respective contracts between the generating stations and beneficiaries or buyers."*

56.3.4. The comments of MSEDCL of allowing a generator to sell power in DAM with the liability of fixed charges on beneficiaries, is clarified that allowing such power under DAM would lead to the availability of power in DAM, leading to overall economy for beneficiaries buying power from DAM. Further, it would allow a generating station to make up for schedules below the Minimum turndown level, making sure that maximum generation is on bar which serves as inertia in the grid. Further the gains by such generating station shall be shared with the beneficiaries as per provisions in the Tariff Regulations.

56.3.5. The draft regulation has been modified as 49 (4) (b) (i) in the 2023 Grid Code Regulations as follows:

“(b) The request for revision of scheduled transaction for ‘D’ day, shall be allowed subject to the following:
(i) Request of buyers for upward revision of schedule from the generating station whose tariff is determined under Section 62 of the Act shall be allowed starting 2 PM on ‘D-1’ day, only in respect of the remaining available quantum of un-requisitioned surplus in such generating stations, after finalization of schedules under day ahead market.”

(ii) Request of buyers for downward revision of schedule from the generating stations, whose tariff is determined under Section 62 of the Act shall be allowed in any time block subject to the provision relating to SCUC under Regulation 46 of these regulations.”

57. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (4) (c))

57.1. **Commission’s Proposal**

57.1.1. The Commission had proposed the following in Regulation 47 (4) (c) of the Draft Regulations:

“(c) Based on the request for revision in schedule made as per sub-clauses (a) and (b) of Clause 4 of this Regulation, any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one.”

57.2. **Comments have been received from SJVN, NERPC, UPSLDC, Enel, Tata Power, Greenko, National Solar Federation, ReNew Power, NHPC and NTPC**

57.2.1. **SJVN Ltd.** And NHPC suggested that a provision may be inserted into this clause as below:

> *“Provided that in the event of unforeseen scenario in Hydro Projects such as high silt, cloud burst, heavy rain, flash flood in the river, the RLDC shall revise the schedules which shall become effective from the 7th / 8th time block, counting the first time block in which the unforeseen scenario of High Silt / Cloud Burst has been reported to be the first one. Also, during the 1st to 6th / 7th time blocks of such an event, the scheduled generation of the ISGS shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised accordingly.”*

SJVN has commented that during such a period, generating plants may have heavily penalized on account of DSM charges due to deviation in schedule. Similarly, when the silt level is on decreasing trend, generating units may not commence generation due to aforesaid CERC IEGC Regulations, as revision in generation is allowed only after 7th or 8th time block.

57.2.2. **NERPC** has suggested that the following provision may be inserted:

> *“For Run-of-the-River hydro generating stations any revision in schedule (by generator and beneficiaries) made in odd time blocks shall become effective from 3rd time block and any revision in schedule made in even time blocks shall become effective from 4th time block, counting the time block in which the*

request for revision has been received by the RLDCs to be the first one."

57.2.3. **UPSLDC** has suggested that between gate closure and market clearing time, revision of schedule should be allowed from 3rd/4th time block. This will help in reduce the area control error of the state and thus help in reliable grid operations.

57.2.4. **Enel, Tata Power, Greenko, National Solar Federation** and **Renew** have suggested that the revision in the schedules should be effective from the 3rd/ 4th time block, respectively.

57.2.5. **NTPC** has suggested that the existing proviso of upward and downward DC revision in 7/8-time blocks may be retained. The existing regulation allows the ISGS generating units to revise their declared capability of the D day with advance notice. Therefore, DC revisions have been allowed only in certain cases of machine forced outages.

57.3. **Analysis and Decision**

57.3.1. With regard to suggestions of SJVN and NHPC for revision of schedule by hydro generating stations, it is clarified that allowing revision puts the buyer in a vulnerable condition to arrange for power in a short period of time. However, the liability of DSM during such forced outage or partial outage may be considered in DSM Regulations.

57.3.2. With regard to the suggestion for revision of schedule by RoR hydro generating stations, the provisions for schedule revision by such generating stations shall be governed on account of forced outage and also in case of forecasting error as per Regulations as mentioned under Regulation 49(7) and 49(9) respectively of these regulations.

57.3.3. The suggestions of UPSLDC and others to make the schedule revisions from the 3rd/4th time block have been noted. The current framework of RTM and gate closure requires a minimum timeframe of 6 time blocks within which RTM and SCED are run. The Commission endeavours to reduce the timeframe of revision in due course of time, considering a reduced timeframe for RTM and other possible measures.

57.3.4. With regard to suggestions of NTPC to allow DC revision as in the 2010 Grid Code, the rationale for non-revision of DC by the generating station except for specified cases of forced outage has been given in Clause 8.4(d)(ii) of the Explanatory Memorandum to the Draft Grid Code Regulations, 2022 reproduced as below:

> *"(ii) DC revision was allowed for generating stations under the 2010 Grid Code. However, issues have been raised by stakeholders stating that once they punch the schedules against the DC, generating stations revise their DC leaving the beneficiary with no option but to procure power from elsewhere. We observe that DC is declared only on day ahead basis. A generating station has visibility on day ahead basis about its unit availability. Further, frequent revision of DC leads to uncertainty and additional costs for the distribution licensees. Accordingly, provision of DC revision has not been included as was prevailing in 2010 Grid Code, except for specified cases of Forced outage."*

However subsequently vide Order 18/SM/2023 dated 18.12.2023 DC revision have been allowed as follows:

> *"8. As noted in the order dated 30.09.2023, the generating station should be able to reasonably estimate its DC on day ahead basis. The revision of DC deprives the beneficiaries of the entitled power and may disturb the portfolio management of the beneficiaries. Frequent revisions of DC create uncertainty for the beneficiaries and must be minimised. However,*

keeping in view the difficulties expressed by various types of generating stations and as reported by Grid-India, in partial modification to the Commission order dated 30.09.2023 in suo-moto Petition 14/SM/2023, we are of the considered view that the generating stations or ESS covered under Regulation 49(7) of the Grid Code, except lignite, gas based thermal generating stations and hydro generating stations, shall be allowed a maximum 4 (four) revisions of Declared Capacity and schedule per day subject to maximum 60 (sixty) revisions during a month, due to reasons such as a partial outage of the unit or variation of fuel quality or any other technical reason to be recorded in writing. The lignite based, gas based thermal generating stations and hydro generating stations shall be allowed for 6(six) revisions of Declared Capacity and schedule in a day subject to maximum 120 (One hundred twenty) revisions during a month, due to reasons such as partial outage of the unit or water availability for hydro generating stations, fuel quality or variations in supply of gas for gas generating stations or any other technical reason to be recorded in writing."

58. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (5) (a))

58.1. **Commission's Proposal**

58.1.1. The Commission had proposed the following in Regulation 47 (5) (a) of the Draft Regulations:

"(5) Grid disturbance of category GD-5:
(a) GD-5 is defined under Regulation 11(2) of CEA Grid Standards as "When forty per cent or more of the antecedent generation or load in a regional grid is lost"."

58.2. **Comments have been received from SRPC, KPTCL, Tata Power, TS Transco, POSOCO and NTPC**

58.2.1. **SRPC** has suggested including GDs as defined under Regulation 11(2) of CEA Grid Standards.

58.2.2. **KPTCL** has suggested that this should be applied to all GDs & the affected parties, if they are not responsible for the sole cause of the disturbance irrespective of the category of the grid disturbance.

58.2.3. **Tata Power** has suggested that if the generating station fails to deliver its scheduled generation due to grid disturbance of category GD 1/2/3/4, it may be liable to DSM payable to the grid without any fault of the generator. Hence the same needs to be clarified.

58.2.4. **NTPC** has commented that in all cases of grid disturbances, generator should be compensated based on the certification issued by the concerned RLDC as it exists in the existing provision of IEGC.

58.2.5. **TS Transco** has suggested that the existing clause may be continued instead of category of GD-5 disturbance only.

58.2.6. **POSOCO** has requested to provide the rationale for excluding GD other than GD-5. POSOCO has requested that this provision shall extended for GD-3 and above disturbances

58.3. **Analysis and Decision**

58.3.1. The stakeholders have suggested that all the categories of Grid Disturbances defined under Regulation 11(2) of CEA Grid Standards may be included under this Clause. The Commission, in the Draft regulation, has proposed to consider only Grid Disturbance of category GD-5. The reasons for the same as provided in the Explanatory Memorandum to the Draft Grid Code Regulations, 2022 reproduced below:

*“**8.10 Grid disturbance of category GD-5***
(a) The 2010 Grid Code provides for treatment of schedules in case of any grid disturbance. Such grid disturbance may lead to outage of a generator or a buyer thereby leading such entity not to adhere to its schedules.

(b) However, NPC submitted the draft for “Methodology of settlement of accounts for bilateral short term and collective transactions, for the period of Grid Disturbance" vide its letter dated 27th January 2017 under the 2010 Grid Code, wherein it was suggested to consider such treatment only for grid disturbance of category GD-5.

(c) The Expert group has also suggested to consider cases of Grid Disturbance of category GD-5 only. Accordingly, the draft Grid Code has proposed to consider only cases under GD-5 category.

...........”

58.3.2. It is observed that a number of events under GD-1 to GD-4 may occur while the GD-5 would not occur frequently. The accounting of revised schedules and actuals and payment to and from the DSM pool account for minor frequently occurring events is not called for. Further, the principle was adopted and suggested by NPC with consultation of all stakeholders. Accordingly, only GD-5 is retained.

58.3.3. The draft regulation has been modified as 49 (5) (a) in the 2023 Grid Code Regulations as follows:

“(5) Grid disturbance of category GD-5:
(a) GD-5 occurs when forty per cent or more of the antecedent generation or load in a regional grid is lost as defined in the CEA Grid Standards.”

59. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (5) (c))

59.1. Commission’s Proposal

59.1.1. The Commission had proposed the following in Regulation 47 (5) (c) of the Draft Regulations:

“(c) Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions shall be deemed to have been revised to be equal to their actual generation for all the time blocks affected by the grid disturbance. Such regional entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the pool account.:

Provided that, in case the beneficiaries or buyers of such regional entity generating station are also affected by such grid disturbance, the scheduled drawals of such beneficiaries or buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations.

Provided further that in case the beneficiaries or buyers of such regional entity generating station are not affected by such grid disturbance and they continue to draw power, the scheduled drawals of such beneficiaries or buyers shall not be revised.”

59.2. Comments have been received from SRPC, Sembcorp, and POSOCO

59.2.1. **SRPC** has suggested that clauses may require suitable amendment keeping in view the following:
In the sub proviso, it is mentioned that in case the beneficiaries or buyers of such regional entity generating stations are not affected by such grid disturbance and they continue to

draw power, the scheduled drawals of such beneficiaries or *buyers* shall not be revised. It would lead to a situation deficit in generation. In any situation, the grid needs to be operated close to its LGB. Any difference created between the injection schedule and the drawal schedule needs to be corrected as soon as possible.

59.2.2. **Sembcorp** has suggested for modification in the clause as follows:

"(c) … *generating stations supplying power under <u>all the transactions</u> including bilateral <u>and collective</u> transactions shall be deemed to have been revised to be equal to their actual generation for all the time blocks affected by the grid disturbance.*

<u>Provided that the generating station or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the estimated time of restoration of the unit post grid disturbance, to SLDC or RLDC, as the case may be. Scheduled generation for such generating station or electricity trader or any other agency selling power from the unit of the generating station shall be deemed to have been revised to be equal to their actual generation till such intimated time for restoration.</u>"

59.2.3. **POSOCO** has suggested that generally in case of downward revision of bilateral transactions for any reason, the buyer schedule also gets revised. From the above clause the same is not clear. Further the refund of energy charge under bilateral transaction may need clarification.

59.3. **Analysis and Decision**

59.3.1. With regard to suggestions of SRPC, it is clarified that accounting under the said Regulation is a post facto adjustment of schedules for the purpose of commercial accounting.

59.3.2. With regard to suggestions of Sembcorp, it is clarified that 'collective transactions' are already covered under sub-clause (d) of this Regulation. Further the suggestion to include a provision informing restoration time etc, is not required since the provisions relating to a forced outage of a generating station are covered under Regulation 49(7), and there is no need to repeat them here.

59.3.3. With regard to suggestions of POSOCO, it is clarified that under the proposed Regulations, the schedule of the buyer may not be revised while revising the schedule of the generator. As explained above, this is a post facto accounting adjustment to cater to DSM liability for entities. Suppose a generator is affected by the grid disturbance whereas the buyer is not affected by the grid disturbance - Such buyers shall keep drawing power unaware of such grid disturbance and cannot be penalised for drawing power. Accordingly, the methodology proposes to revise the schedule of the buyer only when a buyer is also affected by the grid disturbance and not otherwise.

An Illustration is provided herewith for clarity:

Suppose a generating station 'G' has a schedule of 500 MW for all time blocks of the day Suppose the buyer 'B' has a drawal schedule of 2000 MW including 500 MW from 'G' (considering zero losses).

- Suppose 'G' is affected by GD-5 at 2.05 PM and 'B' is not affected by such GD-5.
- The schedule drawal of the buyer would continue to be 2000 MW, including 500

MW from ‘G’.

- Schedule generation of ‘G’ shall be revised as Actual generation for purpose of DSM calculations but for the purpose of billing to buyer Schedule generation of ‘G’ shall be considered as 500 MW only.
- Buyer shall make payment of energy charges for 500 MW to ‘G’, which ‘G’ shall pay back to DSM Account.

59.3.4. The draft regulation has been modified as 49 (5) (c) in the 2023 Grid Code Regulations as follows:

“(c) Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions shall be deemed to have been revised to be equal to their actual generation for all the time blocks affected by the grid disturbance. Such regional entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the <u>Deviation and Ancillary Service Pool Account</u>:

Provided that, in case the beneficiaries or buyers of such regional entity generating station are also affected by such grid disturbance, the scheduled drawals of such beneficiaries or buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations:

Provided further that in case the beneficiaries or buyers of such regional entity generating station are not affected by such grid disturbance and they continue to draw power, the scheduled drawals of such beneficiaries or buyers shall not be revised.”

60. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (5) (f))

60.1. **Commission’s Proposal**

60.1.1. The Commission had proposed the following in Regulation 47 (5) (f) of the Draft Regulations:

“(f) Energy and deviation settlement for the period of any grid disturbance causing disruption in injection or drawal of power shall be done by the concerned RPC(s) in consultation with the concerned RLDC(s).
Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective from 7th block or 8thblock depending on block in which schedule has been revised as first block.”

60.2. **Comments have been received from SRPC, NHPC and Tata Power**

60.2.1. **SRPC** has suggested modifications in the clause as follows:
“……Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective <u>from the time block specified by RLDC and should be</u> within 7th block or 8th block depending on block <u>in which contingency has taken place</u> as first block.”

SRPC has also suggested a modification in the clause,

> *“For all other grid disturbances/grid incidents and based on system condition alert state, emergency state, extreme emergency state and restoration state,*

generation and drawal schedules including collective transactions would be revised by the Regional Load Despatch Centre shall become effective from the time block specified by RLDC and should be within 7th block or 8th block depending on block in which contingency has taken place as first block."

60.2.2. **NHPC** has suggested that the existing regulation may be retained in place of the proposed regulation (f) of (47)(5).

60.2.3. **Tata Power** has suggested that this is a very large time period for effecting the change. It should be reduced to at least the 4th time block.

60.3. **Analysis and Decision**

60.3.1. With regard to suggestions of SRPC, it is clarified that only GD-5 is covered under this Regulation. Further, suppose revised schedules are given by RLDC to some generating stations or drawing entities (other than those covered under sub-clauses (c) and (d) of this Regulation) due to the occurrence of GD-5, such revision shall become effective from the $7^{th}/8^{th}$ time block to give time to generating station /drawing entity to adhere to such revised schedule. As a revision of schedules to the actual generation schedule is for all the time blocks affected by the grid disturbance, as provided in sub-clause (c), it is implied that the block in which contingency has been taken is to be considered as the first block.

60.3.2. The draft regulation has been modified as 49 (5) (f) in the 2023 Grid Code Regulations as follows:

"(f) Energy and deviation settlement for the period of <u>such</u> grid disturbance causing disruption in injection or drawal of power shall be done by the concerned RPC(s) in consultation with the concerned RLDC(s):
Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective from 7th block or 8thblock depending on block in which schedule has been revised as first block."

61. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (6))

61.1. **Commission's Proposal**

61.1.1. The Commission had proposed the following in Regulation 47 (6) of the Draft Regulations:

"(6) The generation schedules and drawl schedules shall be accessible to the regional entities though user credentials controlled access. After the operating day is over at 2400 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of regional entity generating stations and drawal schedule of the States) shall be issued by the concerned RLDC. These schedules shall be the basis for commercial accounting."

61.2. **Comments have been received from ReNew Power**

61.2.1. **Renew Power** has suggested that the generation schedules and drawl schedules shall be accessible /available in the public domain to all regional entities and not limited to applicants only.

61.3. **Analysis and Decision**

61.3.1. The Commission maintains the view that access to generation schedules and drawl schedules should be available to regional entities through controlled access using user credentials. This approach is proposed considering that it would mitigate any potential threats and vulnerabilities to the system from all public entities.

61.3.2. The draft regulation as proposed has been retained.

62. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (7))

62.1. **Commission's Proposal**

62.1.1. The Commission had proposed the following in Regulation 47 (7) of the Draft Regulations:

"(7) In case of forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under bilateral transaction (excluding collective transactions in day ahead market and real time market through power exchange), the generating station or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC or RLDC, as the case may be. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised accordingly. The revised schedules shall become effective from the time block and in the manner as specified in Clause (4) of this Regulation:"

62.2. **Comments have been received from Dhariwal, Jindal India TPL, ReNew Power, Sembcorp, Dans Energy, Jindal India TPL and POSOCO**

62.2.1. **Dhariwal** has suggested that regulation 47(7) may be appropriately modified to allow generators the option to buy power from the Real Time Market in case of forced outages and may also be permitted to buy power from RTM when due to any constraints they are unable to meet the obligation of scheduled generation due to real time technical issues of coal quality etc.

62.2.2. **Jindal India TPL** has suggested the revision of the clause as follows:

"…schedule of beneficiaries, sellers and buyers of power from this / other generating unit(s) shall be revised accordingly on pro rata basis as intimated by generating station. The revised schedules…"

"Provided that the generating station or trading licensee or any other agency selling power from a generating station or unit(s) thereof may revise its schedule after considering its day ahead Open Access Applications / schedules once in a day and estimated restoration time…"

Jindal India TPL has raised the following query**:**

With reference to existing IEGC Regulation Cl.6.5.28, the suppliers are bound to do a pro- rata in each PPA in case of Forced Outage, i.e. pro-rata is to be done on the date of unit tripping and not during the extended period of unit tripping till the time of restoration. But there are several instances where RLDCs have asked Generators to do pro-rata during the extended period of unit tripping and distribute quantum equally in each PPA, if in any PPA the quantum is 1- 2 MW is more or less. Since, Declaring Capacity/ availability in PPAs are the right of Generators and any DC can be declared in PPA as per the availability with the Generator during the extended period of Unit Tripping.

62.2.3. **Renew Power** has commented that there should not be any capacity (MW) linked restriction for revising the schedule under forced outage. In order to ensure grid security, all the generating entities, including wind, solar, hydro etc., which are connected to ISTS (CTU connected) should be allowed to revise the schedule in case of a forced outage and suggested that the clause may be modified as below:

"In case of forced outage of a unit of regional entity generating station, including REGS/RHGS…."

"Provided further that in case of REGS/RHGS, part outage of generating station (outage of single turbine in case of wind generator or invertor set in case of solar generator) shall be considered as forced outage."

62.2.4. **Sembcorp** has suggested that the clause may be modified as below:

"(7) … The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised ~~accordingly~~ <u>on pro-rata basis for all the transactions (excluding collective transactions in day ahead market and real time market through power exchange).</u> The revised schedules…"

62.2.5. **Dans Energy** has requested to revise the schedule for generating capacity or station capacity of more than 100 MW irrespective of unit capacity during the forced outage.

62.2.6. **POSOCO** has suggested that the100 MW capacity mentioned in the clause may be clarified as plant total installed capacity or per unit 100 MW minimum. Further Hydro generating stations is permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods to avoid spillage. The same may be clarified if the declaration is more than installed capacity, the same plant can apply under such clause or not.

62.3. **Analysis and Decision**

62.3.1. With regard to suggestions of Dhariwal to allow the generators the option to buy power in case of forced outages, the Commission has added Regulation 49(10) wherein the generators have been allowed to fulfil their supply obligations by arranging power as per the options specified in this regulation.

62.3.2. The suggestions of Jindal India TPL and SembCorp to include a "pro-rata" revision in the schedule have been accepted and included in Clause (7). The clarification sought by Jindal about freedom to generator to provide DC and schedule to its buyers, it is clarified that share of DC and schedule shall be strictly in terms of the contract entered into between buyer and seller and in any condition, contract should not be violated.

62.3.3. With regard to suggestions of Renew Power to include REGS/RHGS, it is clarified that REGS/RHGS are already included in the definition of generating station and there is no need to specify them separately. However, ESS (as an injecting entity) has been inserted in the Regulation. Further, to cater to forecasting error for wind/solar based generating stations, and RoR generating stations, a new Clause has been inserted as Regulations 49(8) and 49(9) of the 2023 Grid Code.

62.3.4. The suggestions of stakeholders to delete the capacity (MW) linked restriction for revising the schedule on account of forced outage in bilateral transactions, have been accepted.

62.3.5. The draft regulation has been modified as 49 (7) in the 2023 Grid Code Regulations as follows:

"(7) Revision of Declared Capacity and schedule, shall be allowed on account of forced outage of a unit of a generating station or ESS (as an injecting entity) only in case of bilateral transactions and not in case of collective transaction. Such generating station or ESS (as injecting entity) or the electricity trader or any other agency selling power from the unit of the generating station or ESS shall immediately intimate the outage of the unit along with the requisition for revision of Declared Capacity and schedule and the estimated time of restoration of the unit, to SLDC or RLDC, as the case may be. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised on pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from the time block and in the manner as specified in clause (4) of this Regulation:

Provided that the generating station or ESS (as injecting entity) or trading licensee or any other agency selling power from a generating station or unit(s) thereof or ESS may revise its estimated restoration time once in a day and the revised schedule shall become effective from the 7th time block or 8th time block as per clause (4) of this Regulation, counting the time block in which the revision is informed by the generator or ESS to be the first one:

Provided further that the SLDC or the RLDC as the case may be, shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit.

(8) In case of requirement of revision of schedule due to forecasting error, a WS seller may revise its schedule only in case of bilateral transactions and not in case of collective transaction. Such revision of schedule shall become effective from the time block and in the manner as specified in sub-clause (c) of clause (4) of this Regulation.

(9) In case of requirement of revision of Declared Capacity due to forecasting error, a RoR generating station may request for revision of its Declared Capacity and schedule only in case of bilateral transactions and not in case of collective transaction. Such revision shall become effective from the time block and in the manner as specified in sub-clause (c) of clause (4) of this Regulation.

(10) In the event of forced outage of a generating station or unit thereof, the generating company owning the generating station or unit thereof shall fulfil its supply obligation to the beneficiaries which made requisition from such generating station or unit thereof, (i) by entering into contract(s) covered under Power Market Regulations or (ii) by arranging supply from any other generating station or unit thereof owned by such generating company subject to honouring of rights of the original beneficiaries of the said generating station or unit thereof from which the supply is arranged or (iii) through SCED, as applicable."

63. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (8) (a))

63.1. **Commission's Proposal**

63.1.1. The Commission had proposed the following in Regulation 47 (8) (a) of the Draft Regulations:

"(8) Discrepancy in schedule
(a) All regional entities, open access customers, injecting entities and drawee consumers may closely check their transaction Schedule and point out errors, if any, to the concerned LDC.
(b) The final schedules issued by RLDC shall be open to all regional entities and other regional open access entities for any checking and verification, for a period of 5 days. In case any mistake or omission is detected, the RLDC shall make a complete check and rectify the same."

63.2. **Comments have been received from PTC, AP Transco, KPTCL and KSEBL.**

63.2.1. **PTC** has suggested that trading licensees should also be included to check the transaction schedule.

63.2.2. **APTRANSCO** and **KPTCL** have suggested that SLDC and other utilities should be able to approach NLDC/RLDC to point out any discrepancy unless and until the regional energy account is finalized.

63.2.3. **KSEBL** has suggested that RLDCs may be advised to update the WBES as the real time schedules have a commercial impact on the DISCOMs.

63.3. **Analysis and Decision**

63.3.1. The Commission has noted the suggestions of the stakeholders

63.3.2. With regard to suggestion of stakeholders, it has been noted that the Commission has already empowered all regional entities and other regional open access entities to review and verify the final schedules issued by the respective RLDC. The intention behind this regulation is to ensure checks and balances and rectify any deficiencies, if present, so as to ensure the timely availability of accurate scheduling data.

63.3.3. The Commission also supports equitable and impartial opportunities provided to all stakeholders within the designated timeframe; therefore, no preferential treatment should be extended to any specific entity through the regulations.

63.3.4. The draft regulation has been modified as 49 (11) in the 2023 Grid Code Regulations as follows:

"(11) Discrepancy in schedule
(a) All regional entities, open access customers, injecting entities and drawee consumers shall closely check their transaction Schedule and point out errors, if any, to the concerned LDC.
(b) The final schedules issued by RLDC shall be open to all regional entities and other regional open access entities for any checking and verification, for a period of 5 days. In case any mistake or omission is detected, the RLDC shall make a complete check and rectify the same."

64. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (9) (a))

64.1. **Commission's Proposal**

64.1.1. The Commission had proposed the following in Regulation 47 (9) (a) of the Draft Regulations:

“(9) Energy Metering and Accounting:
(a) The CTU shall be responsible for installation, operation and periodic calibration of Interface Energy Meters (IEMs) covering all the ISTS interface points, points of connections between the regional entities, cross border entities and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points.”

64.2. **Comments have been received from CTU, NERPC, WRPC, GRIDCO and POSOCO.**

64.2.1. **CTUIL** has suggested that the Clause may be modified as:
“The CTU <u>shall provide</u> special energy meters/Interface Energy Meters to all transmission licensees/ GENCO’s/ Utilities for all inter connections between the regional entities and other identified points for recording of actual net MWh interchanges and MVArh drawls.”

64.2.2. **NERPC** has suggested that the clause may be modified as:
“<u>The CTU/STU/State Power Department</u> shall be responsible for installation, operation and …”

64.2.3. **WRPC** has commented that the responsibilities are required to be fixed for the proper maintenance of the IEMs. As far as CTU is concerned they may not be in position to installation, operation and periodic calibration of IEMs in the field and suggested that the clause may be modified as below:

> *“The CTU shall be responsible for framing the requirement and procurement of Interface Energy Meters (IEMs) covering all the interface points, points of connections between the regional entities, cross border entities and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points. Also, CTU shall identify the agencies eligible for calibration of the IEMs for every region and the procedure for calibration of the IEMs, in consultation with RPCs/RLDCs. CTU shall chalk out the plan of calibration of all the IEMs in each region in consultation with RLDC/RPC. The Utility which is responsible for maintaining bay equipment’s shall be responsible for installation, operation and periodic calibration of Interface Energy Meters (IEMs) as per the procedure laid out by CTU in consultation with RLDCs/RPCs. CTU shall also be responsible for procuring of the meters for replacement of faulty meters and maintaining adequate spare meters with a designated Utility as per their MoU with that Utility. The requirement of faulty meters and spare meters shall be intimated by RLDCs to CTU. CTU on receipt of requirement for replacement of IEMs from the Utility, shall arrange the IEMs to the Utility. The Utility responsible for maintain the bay equipment’s shall make arrangement to collect the IEMs from CTU and replace the faulty IEMs without any delay. If there exist a technical feasibility, the IEM data can be streamed online to SLDCs and RLDCs for taking operational decisions.”*

64.2.4. **GRIDCO** has suggested that the clause may be modified as below:
“(a) The CTU shall be responsible for installation, operation, periodic calibration, <u>time-synchronization</u> of Interface Energy Meters (IEMs) <u>and confirmation on designated accuracy class i.e. 0.2s for metering core(s)/winding(s) of current transformers & voltage transformers through periodical determination of ratio error and phase angle error</u>,

covering all the ISTS interface points, points of connections between the regional entities….”

64.2.5. **POSOCO** has suggested that the clause may be modified as below:
“(a) The CTU shall be responsible for installation, operation and periodic testing of Interface Energy Meters (IEMs) covering all the ISTS interface points, points of connections between the regional entities, cross border entities and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points. The periodic testing of the IEMs may be done in presence of the concerned regional entities. The defective IEMs shall be replaced by CTU within one week.”

64.3. **Analysis and Decision**

64.3.1. The relevant extract of Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 related to ownership of meters, installation of meters, Operation, Testing and Maintenance of meters are as follows:

> ***“6. Ownership of meters. -***
> *(1)* ***Interface meters***
> *(a) All interface meters installed at the points of interconnection with Inter-State Transmission System (ISTS) for the purpose of electricity accounting and billing shall be owned by CTU.*
> *(b) All interface meters installed at the points of interconnection with Intra-State Transmission System excluding the system covered under sub-clause (a) above for the purpose of electricity accounting and billing shall be owned by STU.*
> *(c) All interface meters installed at the points of inter connection between the two licensees excluding those covered under sub-clauses (a) and (b) above for the purpose of electricity accounting and billing shall be owned by respective licensee of each end.*
> *(d) All interface meters installed at the points of inter connection for the purpose*
> *of electricity accounting and billing not covered under sub-clauses (a), (b) and (c) above shall be owned by supplier of electricity.*
>
> ***7. Installation of meters. –***
> *(1) Generating company or licensee, as the case may be, shall examine, test and regulate all meters before installation and only correct meters shall be installed.*
> *(2) The meter shall be installed at locations, which are easily accessible for installation, testing, commissioning, reading, recording and maintenance. The*
> *place of installation of meter shall be such that minimum inconvenience and disruptions are caused to the site owners and the concerned organizations.*
> *…………………………..*
> *…………………………..*
>
> ***10. Operation, Testing and Maintenance of meters. -***
> *The operation, testing and maintenance of all types of meters shall be carried out by the generating company or the licensee, as the case may be.”*

As per the above, all interface meters installed at the points of interconnection with Inter-

State Transmission System (ISTS) for the purpose of electricity accounting and billing shall be owned by CTU. Since CTU is the owner of such interface meters, the Commission is of the view that CTU should be responsible for the procurement and installation of such interface meters at the cost of the respective entity, including the replacement of faulty meters.

64.3.2. The Commission also observes that as per aforesaid metering regulations, the operation, testing and maintenance of all types of meters shall be carried out by the generating company or the licensee, as the case may be. Accordingly, the Commission is of the view that operation and periodic calibration of such interface meters shall be done by the respective entity.

64.3.3. Regarding the suggestion to include the periodic testing of Interface Energy Meters (IEMs), it is observed that the relevant provision is already mentioned in aforesaid metering regulations. The relevant extracts of the CEA (Installation and Operation of Meters) Regulations, 2006 and its Amendment vide 2019 are as below:

> ***"18. Calibration and periodical testing of meters. –***
> *(1)* ***Interface meter***
> *(a) At the time of commissioning, each interface meter shall be tested by the owner at site for accuracy using standard reference meter of better accuracy class than the meter under test.*
> *(b) All Interface Meters shall be tested on-site using accredited test laboratory for routine accuracy testing at least once in five years and recalibrated if required.*
> *Provided that these meters shall also be tested whenever the energy and other quantities recorded by the meter are abnormal or inconsistent with electrically adjacent meters.*
> *(c) Testing and calibration of Interface Meters shall be carried out in the presence of the representatives of the supplier and buyer by giving the advance notice to the other party regarding the date of testing."*

From the aforesaid metering regulations, it is observed that the at the time of commissioning, each interface meter shall be tested and thereafter the meter shall be tested at least once every five years. The meter shall also be tested whenever the energy and other quantities recorded by it are abnormal or inconsistent with electrically adjacent meters.

64.3.4. Regarding the suggestion to include the accuracy class of Interface Energy Meters (IEMs), it is observed that the accuracy class of Interface Meters with accuracy 0.2S is mentioned under aforesaid metering regulations, and the same shall comply with by the concerned entity.

64.3.5. The draft regulation has been modified as 49 (12) (a) in the 2023 Grid Code Regulations as follows,

"(12) Energy Metering and Accounting:

(a) The CTU shall be responsible <u>for procurement and installation of Interface Energy Meters (IEMs), at the cost of respective entity</u>, at all the ISTS interface points, points of connections between the regional entities, cross border entities and other identified points for recording of actual active and reactive energy interchanged in each time-block through

those points, <u>and its operation and periodic calibration shall be done by the respective entity. CTU shall be responsible for replacement of faulty meters</u>."

65. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (9) (b))

65.1. **Commission's Proposal**

65.1.1. The Commission had proposed the following in Regulation 47 (9) (b) of the Draft Regulations:

"(b) The installation, operation, calibration and maintenance of Interface Energy Meters (IEMs) with automatic remote meter reading (AMR) facility shall be in accordance with CEA (Installation and Operation of Meters) Regulations, 2006, as amended from time to time."

65.2. **Comments have been received from NERPC**

65.2.1. **NERPC** has suggested that in the 192nd OCC meeting held on 21st July, 2022 NEEPCO & CTU opined that calibration of the Static Energy meters is not possible. Accordingly, the word "calibration" may be removed.

65.3. **Analysis and Decision**

65.3.1. Central Electricity Authority (Installation and Operation of Meters) (Amendment) Regulations, 2019 provides that all new Interface Meters shall be of a static type and shall have an automatic remote meter reading facility. The relevant extract is as below:

> *"4 (1) (a) all new Interface Meters and Energy Accounting and Audit Meters shall be of static type and shall have automatic remote meter reading facility;*
> *…*
> *18(1)(b) All Interface Meters shall be tested on-site using accredited test laboratory for routine accuracy testing at least once in five years and recalibrated if required.*
> *Provided that these meters shall also be tested whenever the energy and other quantities recorded by the meter are abnormal or inconsistent with electrically adjacent meters.*
> *18(1)(c) Testing and calibration of Interface Meters shall be carried out in the presence of the representatives of the supplier and buyer by giving the advance notice to the other party regarding the date of testing"*

65.3.2. Accordingly, it is required that CEA Metering Regulations are complied with and the same have been referred to in the 2023 Grid Code.

65.3.3. The draft regulation has been modified as 49 (12) (b) in the 2023 Grid Code Regulations as follows,

"(b) The installation, operation, calibration and maintenance of Interface Energy Meters (IEMs) with automatic remote meter reading (AMR) facility shall be in accordance with the CEA Metering Regulations 2006."

66. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (9) (d))

66.1. **Commission's Proposal**

66.1.1. The Commission had proposed the following in Regulation 47 (9) (d) of the Draft

Regulations:
"(d) CTU shall provide access to such metering data to concerned RLDC and SLDCs."

66.2. **Comments have been received from CTU**

66.2.1. **CTU** has commented that the metering data is either stored in the meter or local PC at the substation premises. CTU does not have any access to this data and suggested that the clause may be deleted. As per CEA metering regulation, "meter data recording and sending to RLDC are the responsibilities of respective Generation company or licensee in whose premises the meters are installed".

66.3. **Analysis and Decision**

66.3.1. The suggestions of CTU have been accepted. The relevant provision of the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 related to Access to meters is as follows:

> *"11. Access to meter. -*
> *The owner of the premises where, the meter is installed shall provide access to the authorized representative(s) of the licensee for installation, testing, commissioning, reading and recording and maintenance of meters."*

66.3.2. The draft regulation has been modified as 49 (12) (d) in the 2023 Grid Code Regulations as follows,

"(d) Access to such metering data to the concerned RLDC and SLDC(s) shall be in accordance with the CEA Metering Regulations 2006."

67. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (9) (e))

67.1. **Commission's Proposal**

67.1.1. The Commission had proposed the following in Regulation 47 (9) (e) of the Draft Regulations:

"(e) CTU shall be responsible for installation of Automatic Meter Reading and shall ensure that all IEMs not capable of having the facility of AMR are phased out within two (2) years on effectiveness of these regulations."

67.2. **Comments have been received from CTU.**

67.2.1. **CTU** has commented that Installation of AMR would automatically include phasing out of AMR non-compliant meters and suggested that the words "and shall ensure that all IEMs not capable of having the facility of AMR are phased out within two (2) years on effectiveness of these regulations." may be removed.

67.3. **Analysis and Decision**

67.3.1. It is noted that metering is required to be as per CEA Metering Regulations and accordingly, a separate provision in the 2023 Grid Code is not required. The provision regarding phasing out within two years as proposed in the Draft Regulations has been removed.

68. Procedure for Scheduling and Despatch for Inter-State Transactions

(Regulation - 47 (9) (g))

68.1. **Commission's Proposal**

68.1.1. The Commission had proposed the following in Regulation 47 (9) (g) of the Draft Regulations:

"(g) SLDC shall transmit the meter data from all installations within their control area to the concerned RLDC within the specified time schedule."

68.2. **Comments have been received from POSOCO**

68.2.1. POSOCO has suggested that clause (g) of 47(9) may be deleted.

68.3. **Analysis and Decision**

68.3.1. The suggestions of POSOCO have been accepted. The draft regulation 47(9)(g) has been deleted.

69. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (9) (j))

69.1. **Commission's Proposal**

69.1.1. The Commission had proposed the following in Regulation 47 (9) (j) of the Draft Regulations:

"(j) RLDC shall forward the IEM readings and the implemented schedule to the concerned RPC on a weekly basis by each Friday for the preceding seven days period ending on the preceding Sunday mid-night, to enable the latter to prepare and issue the various accounts such as Deviation Settlement Mechanism (DSM), reactive charges, congestion charges, ancillary services, SCED, heat rate compensation charges and regional transmission deviation in accordance with relevant regulations."

69.2. **Comments have been received from WRPC**

69.2.1. **WRPC** has suggested that instead of Friday, if the data is received by Thursday, the accounts can be prepared, checked, and issued by the following Tuesday by RPCs. **WRPC** also suggested that the AGC may be added to the list of accounts.

69.3. **Analysis and Decision**

69.3.1. The suggestions of WRPC have been accepted.

69.3.2. The draft regulation has been modified as 49 (12) (h) in the 2023 Grid Code Regulations as follows:

"(h) RLDC shall forward the IEM readings and the implemented schedule to the concerned RPC on a weekly basis by each Thursday for the preceding seven days period ending on the preceding Sunday mid-night, to enable the latter to prepare and issue the various accounts such as Deviation Settlement Mechanism (DSM), reactive charges, congestion charges, ancillary services, SCED, heat rate compensation charges, and regional transmission deviation in accordance with relevant regulations and Annexure 7 of these regulations."

70. Procedure for Scheduling and Despatch for Inter-State Transactions (Regulation - 47 (10))

70.1. **Commission's Proposal**

70.1.1. The Commission had proposed the following in Regulation 47 (10) of the Draft Regulations:

"(10) Inspection of Records: The operational logs and records of the regional entity generating stations and inter- State transmission licensees shall be available for inspection and review by the RLDCs and RPCs."

70.2. **Comments have been received from POSOCO**

70.2.1. **POSOCO** has suggested that the number of years for which the operational logs and records are to be maintained may be mentioned.

70.3. **Analysis and Decision**

70.3.1. The number of years may be included in the Operating Procedure by NLDC/RLDCs based on requirement. The draft regulation has been retained as Regulation 49 (13) in the 2023 Grid Code Regulations.

CHAPTER 8 - CYBER SECURITY

1. General (Regulation 48 (2))

1.1. **Commission's Proposal**

1.1.1. The Commission had proposed the following in Regulation 48 (2) of the Draft Regulations:

"(2) All users, NLDC, RLDCs, SLDCs, CTU and STUs shall have in place, a cybersecurity framework in accordance with Information Technology Act, 2000; CEA (Technical Standards for Connectivity) Regulations, 2007; CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations issued from time to time, by an appropriate authority, so as to support reliable operation of the grid."

1.2. **Comments have been received from CTU, POSOCO and HPSLDC**

1.2.1. **CTU** has suggested that Inter-State transmission licensee and ISGS GENCOs should also have a cyber security framework.

1.2.2. **POSOCO** has suggested modifying the regulation as follows:

"All users, NLDC, RLDCs, SLDCs, CTU and STUs shall have in place, a cyber-security framework <u>(in line with the commonly known cybersecurity frameworks like NIST Cyber Security Framework, ISO 27001 and 27002, SOC2, NERC-CIP etc.) and shall follow cyber security practices</u> in accordance with Information Technology Act, 2000 <u>amended from time to time;</u> CEA (Technical Standards for Connectivity) Regulations, 2007; CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations <u>and Amendments</u> issued from time to time, by an appropriate authority, so as to support reliable operation of the grid".

POSOCO has further suggested inserting new clauses in the Regulation 48,

(3) The appropriate entity shall also take due diligence of the relevant provisions of various Guidelines and Codes being issued by various statutory authorities, list of which shall be published by the concerned Sectoral CERT time to time.
(4) The entities shall as per CERT-In guideline certify their business functions including IT & OT for ISO27001 Standard and shall continue to comply to the requirement of standard within 3 (three) months from publication of this Regulation.

1.2.3. **HPSLDC** has suggested adding new clauses in the regulation 48.

(3) Due to adoption of advanced technologies for monitoring and automation of power system, all Field equipment / Operational Technology (OT) shall be tested from designated laboratories for cyber security conformance and shall be in conformance with the latest communication and security protocol standards.
(4) Every organization shall implement ISO 27001: Information Security Management Systems (ISMS) and form Information Security Division (ISD), ISD must be functional on 24x7 (Round the Clock) basis and is manned by sufficient numbers of IT Engineers having valid certificate of successful completion of course on cyber security of Power Sector for maintaining cyber security.

(5) Electronic Security Perimeter: The organization shall identify and document the Electronic Security Perimeter(s) and all Access Points to the perimeter(s) as per IEC 62443 / IS16335 (as amended from time to time). Each organization shall ensure that every Critical System resides within an Electronic Security Perimeter. Cyber-Vulnerability Assessment of all electronic Access Points connected within the Electronic Security Perimeter(s) should be performed at least once in every 6 (six) months and/or after any change in the Security Architecture.

(6) Security and Testing of Cyber Assets: The organization shall ensure security of all in-service phase as well as standby Cyber Assets through regular firmware/Software updates and patching, Vulnerability management, Penetration testing (of combined installations), securing configuration, supplementing security controls. A separate test execution environment shall be configured for testing of all patches prior to their implementation. Cyber assets hardening shall also be performed in the testing environment to both identify potential gaps and evaluate possible physical impact.

1.3. **Analysis and Decision**

1.3.1. The Commission has noted the suggestions of the stakeholders.

1.3.2. With regard to the suggestion to include inter-State Transmission Licensee and ISGS GENCOs, it is observed that all users must comply with this regulation and 'users' includes inter-State Transmission Licensee and ISGS.

1.3.3. The Commission observes that some entities such as power exchanges, QCAs, and SNAs are not covered under this regulation and accordingly, the Draft regulation has been modified at Regulation 50(2) of these regulations to explicitly incorporate these entities.

1.3.4. Some stakeholders have suggested modifying the proposed regulation as well as adding some provisions. However, the Commission believes that the aspects of cyber security have already been extensively covered under the CEA (Cyber Security in Power Sector) Guidelines, 2021. In response to stakeholders' suggestions, it is important to note that several key points covered in the said CEA Guidelines are as follows:

"

- *Government of India has set up the Indian Computer Emergency Response Team (CERTIn) for Early Warning and Response to cyber security incidents and to have collaboration at National and International level for information sharing on mitigation of cyber threats.*
- *Ministry of Power has created 6(six) sectoral CERTs namely Thermal, Hydro, Transmission, Grid Operation, RE and Distribution for ensuring cyber security in Indian Power Sector. Each Sectoral CERT has prepared their sub-sector specific model Cyber Crisis Management Plan(C-CMP) for countering cyber-attacks and cyber terrorism. Each Sectoral CERT has circulated their model C-CMPs for preparation and implementation of organization specific C-CMP by each of their Constituent Utility.*
- *All Responsible Entities, Service Providers, Equipment Suppliers/Vendors and Consultants engaged in Power Sector are equally responsible for ensuring cyber security of the Indian Power Supply System. They are to act timely upon each threat intelligence, advisories and other inputs received from authenticated sources, for continuous improvement in their cyber security posture.*
- *There is hard isolation of their OT Systems from any internet facing IT system.*

- *List of whitelisted IP addresses for each firewall is maintained by CISO and each firewall is configured for allowing communication with the whitelisted IP addresses only.*
- *Communication between OT equipment/systems is done through the secure channel preferably of POWERTEL through the fibre optic cable. Security configuration of the communication channel is also to be ensured.*
- *All ICT based equipment/system deployed in infrastructure/system mandatorily CII are sourced from the list of the "Trusted Sources" as and when drawn by MoP/CEA.*
- *The Responsible Entity shall be ISO/IEC 27001 certified (including sector specific controls as per ISO/IEC 27019)*
- *The Responsible Entity shall have a Cyber Security Policy drawn upon the guidelines issued by NCIIPC.*
- *The CISO shall record the exemptions sought in statement of applicability controls, while getting the ISO 27001 certified. All exemptions and its justification need to be in conformance with Cyber Security Policy of the Responsible Entity.*
- *Identification of Critical Information Infrastructure (CII).*
- *Cyber Risk Assessment and Mitigation Plan*
- *The Cyber Security Audit shall be as per ISO/IEC 27001 along with sector specific standard ISO/IEC 27019, IS 16335 and other guidelines issued by appropriate Authority if any.*
- *The Responsible Entity shall ensure that all Communicable devices are tested for communication protocol as per the ISO/IEC/IS standards listed in MoP Order No. 12/13/2020-T&R dated 8th June, 2021(Annexure-B)."*

1.3.5. The draft regulation has been modified as 50 (2) in the 2023 Grid Code Regulations as follows:

"(2) All users, NLDC, RLDCs, SLDCs, CTU and STUs, <u>power exchanges, QCAs, SNAs,</u> shall have in place, a cyber security framework in accordance with Information Technology Act, 2000; CEA (Technical Standards for Connectivity) Regulations, 2007; CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations issued from time to time, by an appropriate authority, so as to support reliable operation of the grid."

2. Cyber Security Audit (Regulation 49)

2.1. Commission's Proposal

2.1.1. The Commission had proposed the following in Regulation 49 of the Draft Regulations:

"All users shall conduct Cyber Security Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority."

2.2. Comments have been received from SRPC, Hitachi Energy, and POSOCO

2.2.1. **SRPC** suggested that NLDC, RLDCs, SLDCs, CTU, STUs and Control Centres should also conduct cyber security audits as per the guidelines.

2.2.2. **Hitachi Energy** recommended mentioning Periodic Cyber security audit for at least yearly once or whenever an incident is reported.

2.2.3. **POSOCO** has commented that all open vulnerabilities are suitably addressed and closed based on the findings of the audits being conducted and reported to the sectoral CERTs and statutory agencies for record and observance, and suggested modifying as follows:

“All users shall conduct Cyber Security <u>and Information Security</u> Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority. <u>The utilities shall confirm the sectoral CERT regarding compliance to the findings of the Audit process referred above as per the provisions stipulated in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority.”</u>

2.3. **Analysis and Decision**

2.3.1. It is observed that the 2023 Grid Code refers to the Cyber Security Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority; Accordingly, no changes are required to address the suggestions of stakeholders as the periodicity and other details shall be as per the referred guidelines.

2.3.2. The SRPC suggestion has been accepted, and the draft regulation has been modified as 51 in the 2023 Grid Code Regulations as follows.

“51. CYBER SECURITY AUDIT
All users, <u>NLDC, RLDCs, SLDCs, CTU and STUs, power exchanges, QCAs, SNAs,</u> shall conduct Cyber Security Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority.”

3. Mechanism of Reporting (Regulation 50 (1) & (2))

3.1. **Commission’s Proposal**

3.1.1. The Commission had proposed the following in Regulation 48 (2) of the Draft Regulations:

“(1) All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000 in case of any cyber-attack.

(2) NLDC, RLDCs, SLDCs, RPCs and the Commission shall also be informed by such entities in case of any instance of cyber-attack.”

3.2. **Comments have been received from POSOCO**

3.2.1. **POSOCO** has commented that prevailing CERT-In directions relating to information security practices, procedures, prevention, response and reporting of cyber incidents includes a provision for reporting any cyber incident within 6 hours of noticing such incidence to CERT-In. Further, CERT-In also coordinates with the sectoral CERTs to ensure necessary action for immediate mitigation of the incidence reported and further conducting Root Cause Analysis of the same to prevent recurrences. Any open vulnerabilities being found need to be suitably closed. Further, risk analysis of the Cyber security posture of the utility needs to be done to ensure mitigation of gaps. Utilities need to be directed and suitably bound to adhere such practices through regulatory provisions to mandate the Cyber security best practices. CERT-In and NCIIPC are also periodically releasing Indicators of compromise (IOCs) and Indicators of Attack (IOAs) for the relevant utilities. These are alerts that the utility needs to address and ensure suitable prevention of the same as per guidelines provided by the IOCs and IOAs. Further, compliance with the same is being monitored by the statutory agencies through sectoral CERTs.

POSOCO has suggested modifying as follows:

"(1) All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000 (as per latest amendment), provisions of CERT-In Directions under sub-section (6) of section 70B of the Information Technology Act, 2000 published dated 28.04.2022 and any such regulations issued from time to time, by an appropriate authority in case of any cyber-attack

(2) Any such incident should also be parallelly reported to appropriate Sectoral CERT for ensuring necessary follow-up.

(3) NLDC, RLDCs, SLDCs, RPCs and the Commission shall also be informed by such entities in case of any instance of cyber-attack / incidence.

(4) All entities shall ensure necessary monitoring, reporting and compliance to the advisories received from the stipulated statuary agencies (such as CERT-In, NCIIPC etc.) as per the required timeline. A detailed procedure indicating timelines, reporting formats and compliance requirement shall be prepared by the respective Sectoral CERT in this direction for necessary adherence by all concerned utilities."

POSOCO has also suggested adding a new regulation, as currently no suitable Forum or Platform is available to discuss the various Cyber Security incidents and action taken against the same. A suitable forum under CERT-GO and comprising SLDCs, RLDCs and NLDC shall be constituted.

(51) CYBER SECURITY COORDINATION FORUM

The appropriate sectoral CERT shall form a Cyber Security Coordination Forum with members from all concerned utilities and other statutory agencies to coordinate and deliberate on the cyber security challenges and gaps at appropriate level. A sub-committee of the same shall be formed at the regional level.

(The sectoral CERT shall prepare a detailed procedure indicating the composition of the Forum, meeting frequencies, Roles and responsibilities etc. in this regard. All concerned utilities shall accordingly, adhere to the deliberations and decisions of the Cyber Security Coordination Forum.

."

3.3. **Analysis and Decision**

3.3.1. The suggestions to insert the Cyber Security Coordination Forum have been accepted. The other specific detailing is not added in the 2023 Grid Code and shall be as per applicable Guidelines and Act.

3.3.2. It is observed from CEA website, the Sectoral CERTs by Government of India as follows:

Power Sector – Information Sharing and Analysis Center (ISAC – Power)

Cyber security of Critical Infrastructure is a growing concern among business and Governments worldwide. The Government of India, through Information Technology Act-2000 laid the foundation of CERT-In, an organization dedicated to the cause of Cyber Security standards, compliances, Incident Response and Guidance. The Government of India after reviewing the needs of cyber security in Critical Infrastructure sector, created dedicated Sectoral CERTs.

Following the directives of GOI/ CERT-In, MOP created six sectoral CERTs:

S.No.	Sectoral CERT	Nodal Organization
1.	CERT – Thermal	NTPC
2.	CERT – Hydro	NHPC
3.	CERT – Transmission	POWERGRID
4.	CERT – Distribution	DP&T Division, CEA
5.	CERT – Grid Operation	NLDC
6.	CERT – Renewable Energy	MNRE/SECI

Further, the Government of India, under the provision of Information Technology Act, 2000 created National Critical Information Infrastructure Protection Centre (NCIIPC). Following the best practices in the area of Cyber Security, a central coordinating agency to share and analyze various cyber security incidents in the Power Sector, Information Sharing and Analysis Centre (ISAC-Power) was conceived. The ISAC-Power will be the common platform for the six Sectoral CERTs under Ministry of Power. The ISAC-Power will focus to be the Central Information Resource pooling and sharing platform.

3.3.3. The draft regulation has been modified as regulation 52 and new regulation has been added as 53 in the 2023 Grid Code Regulations as follows.

"52. MECHANISM OF REPORTING
(1) All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000, as amended from time to time, and CEA (Cyber Security in Power Sector) Guidelines, 2021, in case of any cyberattack.
(2) NLDC, RLDCs, SLDCs, RPCs and the Commission shall also be informed by such entities in case of any instance of cyber-attack.

53. CYBER SECURITY COORDINATION FORUM
(1) The sectoral CERT (Computer Emergency Response Team) for wings of power sector, as notified by Government of India, from time to time, shall form a Cyber Security Coordination Forum with members from all concerned utilities and other statutory agencies to coordinate and deliberate on the cyber security challenges and gaps at appropriate level. A sub-committee of the same shall be formed at the regional level.
(2) The sectoral CERT shall lay down rules of procedure for carrying out their activities."

Chapter – 9 – MONITORING AND COMPLIANCE CODE

1. Assessment of Compliances (Regulation 52)

1.1. Commission's Proposal

1.1.1. The Commission had proposed the following in Regulation 52 of the Draft Regulations:

"The performance of all users, CTU, STUs, NLDC, RLDCs, SLDCs and RPCs with respect to compliance of these regulations shall be assessed periodically."

1.2. Comments have been received from CTU

1.2.1. **CTU** has suggested adding Inter-state Transmission Licensee and ISGS-GENCOs to the performance assessment list,

1.3. Analysis and Decision

1.3.1. The Inter-state Transmission Licensee and ISGS-GENCOs are already included in 'Users'.

1.3.2. The Commission observes that some entities such as power exchanges, QCAs, and SNAs are not covered under this regulation and accordingly, the Draft regulation has been modified at Regulation 55 of these regulations to explicitly incorporate power exchanges, QCAs and SNAs as well.

1.3.3. The draft regulation has been modified as regulation 55 in the 2023 Grid Code Regulations as follows:

"The performance of all users, CTU, STUs, NLDC, RLDCs, SLDCs and RPCs, <u>power exchanges, QCAs, SNAs</u> with respect to compliance of these regulations shall be assessed periodically."

2. Monitoring of Compliances (Draft Regulation 53 (2) (d))

2.1. Commission's Proposal

2.1.1. The Commission has proposed the following in Regulation 53 (2) (d) of the Draft Regulations:

"(h) The self-audit reports of NLDC, RLDCs, CTU, and RPCs shall be submitted to the Commission. The self-audit report of SLDC and STUs shall be submitted to the concerned SERC.

2.2. Comment has been received from Prayas (Energy Group)

2.2.1. **Prayas EG** has suggested that the self-audit reports should be published on the website of the CERC and SERCs within 30 days of the report being submitted to the respective commission. Commissions should also prepare annual compliance reports and make them available on their websites.

2.3. Analysis and Decision

The Commission has noted the suggestion and is of the view that the decision regarding the publication of self-audit reports on the website of the CERC and SERCs may be made by CERC and SERCs at an appropriate time considering the sensitivity of the documents.

3. Monitoring of Compliances (Regulation 53 (2) (h))

3.1. Commission's Proposal

3.1.1. The Commission had proposed the following in Regulation 53 (2) (h) of the Draft Regulations:

"(h) The Regional Power Committee (RPC) in the region shall also continuously monitor the instances of non-compliance of the provisions of these regulations and endeavour to sort out all operational issues and deliberate on the ways in which such cases of non-compliance shall be prevented in future by building consensus. The Member Secretary of respective RPCs may also report any unresolved issues to the Commission."

3.2. Comments have been received from POSOCO and MPPMCL

3.2.1. **POSOCO** has suggested removing the words "by building consensus" from the clause.

3.2.2. **MP Power Management Company** has commented that this regulation would be an additional burden on the users. Submitting the self-audit (compliance) report to the RLDC or SLDC will be an additional burden and repeated exercise for the users. Accordingly, the proposed provision may be dropped.

3.3. Analysis and Decision

3.3.1. With regard to suggestions of MPPMCL, the Commission firmly believes that conducting self-audits by the users and submitting the audit reports to the monitoring agency are essential measures to ensure proper compliance with these regulations.

3.3.2. Considering suggestions of POSOCO "by building consensus" is deleted.

4. Monitoring of Compliances (Regulation 53 (3))

4.1. Commission's Proposal

4.1.1. The Commission had proposed the following in Regulation 53 (3) of the Draft Regulations:

"(3) Independent Third-Party Compliance Audit:
The Commission may order independent third-party compliance audit for any user, CTU, NLDC, RLDC and RPC as deemed necessary based on the facts brought to the knowledge of the Commission."

4.2. Comments have been received from Torrent Power

4.2.1. **Torrent Power Limited** has suggested amending the draft Regulations to remove the reference to distribution licensees (from 'user') and SLDC. It is the State Commission that has jurisdiction to mandate the distribution licensees to carry out such audits – self/third party. Similarly, in the case of SLDC, the appropriate authority shall also be the State Commission.

4.3. Analysis and Decision

4.3.1. It is clarified that as an integrated grid all 'users' are covered by the 2023 Grid Code and need to comply with the 2023 Grid Code. The third party compliance audit of any user or RLDC or RPC shall be constituted only when deemed necessary. The draft regulation has been modified as regulation 56 (3) in the 2023 Grid Code Regulations, to include *power exchange, QCA, SNA also for third party audit,* as follows,

"(3) Independent Third-Party Compliance Audit:

The Commission may order independent third-party compliance audit for any user, power exchange, QCA, SNA, CTU, NLDC, RLDC and RPC as deemed necessary based on the facts brought to the knowledge of the Commission."

ANNEXURES

1. Annexure - 1 (Clause 4)

1.1. Commission's Proposal

1.1.1. The Commission had proposed the following in Clause 4 of the Draft Regulations:

"4) The minimum set of points on which checking and validation shall be carried out is covered in this clause. The detailed list shall be prepared by checking and validation team in consultation with concerned entity, RLDC and RPC."

1.2. Comments have been received from Power Grid

1.2.1. **Power Grid** has suggested removing RLDC from the above clause. As per CEA grid standards, RPC is the nodal entity for protection system.

1.3. Analysis and Decision

1.3.1. It is noted that RPC is already included in the clause and no change is required.

1.3.2. The provision as proposed in the Draft Regulations has been retained.

2. Annexure - 1 (Clause 4 (c))

2.1. Commission's Proposal

2.1.1. The Commission had proposed the following in Clause 4 (c) of the Draft Regulations:

"c) Busbar Protection Relay"

2.2. Comments have been received from KSEBL

2.2.1. **KSEBL** has suggested including the following:

- Check Zone is provided or not
- LBB is connected with Bus bar trip
- Status of PT switching relay in the case of high impedance relay, if applicable.

2.3. Analysis and Decision

2.3.1. With regard to suggestions of KSEBL it is clarified that the regulation already provides that these are minimum set of points on which checking and validation is required to be carried out. The detailed list shall be prepared in consultation with entity, RPC and RLDC. Accordingly, additional points may be included as agreed with RLDC, RPC and the entity.

2.3.2. The provision as proposed in the Draft Regulations has been retained.

3. Annexure - 1 (Clause 5 (i))

3.1. Commission's Proposal

3.1.1. The Commission had proposed the following in Clause 5 (i) of the Draft Regulations:

"5) Summary of Checking: The summary shall specifically mention minimum following points:

(i) The settings and scheme adopted are in line with agreed protection philosophy or any accepted guidelines (e.g. Ramakrishna guidelines or CBIP manual based).”

3.2. Comments have been received from SECI

3.2.1. **SECI** has suggested modifying the clause as

“…or CBIP manual based <u>or *OEM recommendation / manual*</u>).”

3.3. Analysis and Decision

3.3.1. It is clarified that Ramakrishna *guidelines or CBIP manual* are only cited as examples and OEM recommendations/manual may be referred too. However, the guidelines to be followed should be accepted at the RPC level for uniformity. The provision as proposed in the Draft Regulations has been retained.

4. Annexure - 3 (Clause 5)

4.1. Commission’s Proposal

4.1.1. The Commission had proposed the following in Clause 5 of the Draft Regulations:

“5. The total reserves in a region shall be algebraic sum of reserves in each state control area. However, due to diversity within the region, the Region as a whole might need lesser reserves of secondary and tertiary reserves. As such, All India reserve capacity is taken as equal to reference contingency i.e 4500 MW and this reserve requirement shall be distributed pro-rata amongst the regions based on regional ACE which shall further be divided to identify the share of each state based on 99 percentile ACE of such State control area.”

4.2. Comments have been received from SRPC

4.2.1. SRPC has suggested modifying the clause as below:

“…regions based on regional ACE <u>and the secondary and tertiary reserve at regional level will be maintained accordingly. The same Regional Secondary and Tertiary Reserve</u> shall further be divided …”

SRPC has commented that presently Tertiary Reserves are to be maintained equal to Secondary Reserves and it may be brought out clearly in Regulations.

4.3. Analysis and Decision

4.3.1. Considering suggestions of SRPC, Clause 5 of Annexure - 3 of the 2023 Grid Code Regulations has been modified as follows:

“5. The total reserves in a region shall be algebraic sum of reserves in each state control area. However, due to diversity within the region, the Region as a whole might need lesser reserves of secondary and tertiary reserves. The reserve requirement shall be based on regional ACE which shall further be divided to identify the share of each state based on 99 percentile ACE of such State control area. <u>The All -India Total of Positive (and Negative) secondary reserve capacity requirement on regional basis shall be equal to the reference contingency or secondary reserve capacity requirement based on regional ACE, whichever is higher, subject to the economic utilization of the resource available in the system while ensuring grid security</u>.”

5. Annexure - 4 (Clause 1 (1)(a))

5.1. Commission's Proposal

5.1.1. The Commission had proposed the following in Clause 1 (1)(a) of the Draft Regulations

"(1)

(a) The regional entity pays for VAr drawal when voltage is below 97%"

5.2. Comments have been received from WRPC

5.2.1. **WRPC** has suggested a modification in the clause:

"(a) The regional entity/generating station pays for VAr drawal when voltage is below 97%"

5.3. Analysis and Decision

5.3.1. The word "regional entity" includes a generating station and a separate addition is not required.

5.3.2. The provision as proposed in the Draft Regulations has been retained.

6. Annexure - 4 (Clause 1 (2))

6.1. Commission's Proposal

6.1.1. The Commission had proposed the following in Clause 1 (2) of the Draft Regulations:

"(2) The charge for VArh shall be at the rate of 5 paise/kVArh w.e.f. the date of effect of these regulations. This rate shall be escalated at 0.5 paise/kVArh per year thereafter, unless otherwise revised."

6.2. Comments have been received from POSOCO, SRPC, NTPC and MPPMCL

6.2.1. **POSOCO** has suggested adding the following to the clause:

"Provided that this shall be applicable till such time regulatory framework for voltage control ancillary services is notified."

6.2.2. **SRPC** has suggested modifying the clause as below:

"The charge for VArh shall be at the rate of 5 paise/kVArh for payment into pool and the charge for VArh shall be at the rate of 2.5paise/kVArh for receiving payment from the pool w.e.f. the date of effect of these regulations. This rate shall be escalated at 0.5 paise/kVArh (payment to pool) and 0.25 paise/kVArh (receivable from pool) per year thereafter, unless otherwise revised"

SRPC has commented that more receivables are there than payables in the Regional Reactive Account, if the differential amount is not created (higher for payable and lesser for receivable) there may be a huge outflow from the pool account.

6.2.3. **MP Power Management Company** has commented that, the existing provision of charging 10 Paise/kVArh should continue.

6.2.4. **NTPC** has suggested that the charge of VArh may be provided in line with the existing rate of 10 paise/kVArh. This shall provide the RE generators to optimize the reactive power management by actively participating in Reactive Power

6.3. Analysis and Decision

6.3.1. With regard to suggestions of POSOCO, it is clarified that once modified regulatory framework for voltage control ancillary services would be introduced, the said clause would be require an amendment which would be taken up as required.

6.3.2. With regard to suggestions of SRPC to reduce the rate and that of MPPMCL to keep it is 10 paise/KVARh, it is clarified that the rate under the draft regulations as explained in the Explanatory Memorandum was calculated on the basis of cost of obtaining reactive power from a reactor and is not reduced as of now. Further keeping in view the need to incentivise reactive power support the rates are retained as proposed in the draft regulations.

6.3.3. The provision as proposed in the Draft Regulations has been retained.

7. Annexure - 4 (Clause 2 (3))

7.1. Commission's Proposal

7.1.1. The Commission had proposed the following in Clause 2 (3) of the Draft Regulations:

"(3) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing reactive power support, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS."

7.2. Comments have been received from Siemens, NTPC, and SRPC

7.2.1. **Siemens** has suggested that the Commission should suitably define the incentives for providing fast acting dynamic reactive power compensation capability in case of faults / contingencies on a per event basis e.g. Rs. … per kVAR per event.

7.2.2. **NTPC** has suggested that,

i) Elaborate mechanism for commercial settlement of Generators/IBRs exchanging of VARs with Grid may also be provided in Annexure-4 as provided for others.

NTPC has also suggested that, a voltage range beyond ±3% may be proposed for Ancillary voltage support service. Therefore, the CEA connectivity regulation voltage range is to be revised and PF /Q control may be removed so that single control philosophy of voltage control mode can be followed so that developers can design system economically for TBCB tender and grid compliant. The voltage support at night/non-solar hours by the solar plant is optional to Developers it should be covered under Voltage ancillary service, and it should not be mandated in the CEA Connectivity standard. Accordingly, the Clause may be modified as:

"3) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per <u>revised</u> CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing <u>optional</u> reactive power support <u>under Voltage Ancillary service</u>, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS."

7.2.3. **SRPC** has suggested modifying the clause as below:

"All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary reactive power capability, as per CEA Connectivity Standards, all the time. Further reactive power absorption/injection would be ensured under direction of SRLDC/SLDC during non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing reactive power support, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS. NLDC would come out with Procedure for arriving active power consumed by these devices for purpose of providing reactive power support would be brought out by NLDC."

7.3. Analysis and Decision

7.3.1. The suggestions of Siemens to consider fast acting dynamic reactive power devices, shall be considered appropriately while finalising a separate framework for Voltage control ancillary services under Ancillary services regulations.

7.3.2. With regard to suggestions of NTPC, it is clarified that the mechanism for reactive power compensation is applicable for all generating units including IBRs. Further it is clarified that all generating units are required to maintain power factor as per CEA Standards. The commercial mechanism provided in Annexure-4 is to provide incentive/disincentives with the condition that the mandates of CEA Standards must be complied with at all times.

7.3.3. With regard to suggestions of SRPC, it is clarified that broad principles of treatment of active power consumed by these devices for the purpose of providing reactive power support, were included in the Explanatory Memorandum to Draft Grid Code. NLDC may issue a Procedure after consultation with RPCs, in case the same is required.

7.3.4. The Commission has noted the suggestions of the stakeholders

7.3.5. The provision as proposed in the Draft Regulations has been retained.

8. Annexure - 4 (Clause 1 (4))

8.1. Commission's Proposal

8.1.1. The Commission had proposed the following in Clause 1 (4) of the Draft Regulations:

"(4) For IBRs of capacity 50 MW and below not coming directly to the point of interconnection but through the pooling at the Power Park Developer end, the Power Park Developer shall act as aggregator for the Reactive Energy Charges for payments to and from the Pool Account at RLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer."

8.2. Comments have been received from SRPC

8.2.1. **SRPC** has suggested adding a new clause as below:

"(5) The weekly reactive power at Regional Level account will be made Net Zero if receivables are more than payable. If payable are more than receivable in a week the balance amount will be transferred to Reactive Pool Account."

SRPC has commented that it has been seen that more receivables are there than payables in the Regional Reactive Account. If the differential amount is not created (higher for payable and lesser for the receivable) there may be a huge outflow from the pool account if accounts are not settled on a weekly basis.

8.3. Analysis and Decision

8.3.1. The suggestion to make an account as net zero is not accepted, since incentives for providing reactive power need to be paid. Any shortfall shall be met in accordance with DSM Regulations. The provision as proposed in the Draft Regulations has been retained.

9. Annexure - 4 (Clause 2)

9.1. Commission's Proposal

9.1.1. The Commission had proposed the following in Clause 2 of the Draft Regulations:

"Case – 1: Interconnecting line owned by State-A Metering Point: Substation of State-B

Case - 2: Interconnecting line owned by State-B Metering point: Substation of State-A

Case – 3: Interconnecting line is jointly owned by States-A and –B. Metering points: Substations of State-A and State-B
Net VArh exported from S/S-A, while voltage < 97% = X1 Net VArh exported from S/S-A, while voltage > 103% = X2 Net VArh imported at S/S-B, while voltage < 97% = X3 Net VArh imported at S/S-B, while voltage > 103% = X4"

9.2. Comments have been received from POSOCO, SRPC, NHPC

9.2.1. **POSOCO** has suggested a modification,
"Case – 1: ~~Interconnecting line owned by State-A~~ Metering Point*:* Substation of State-B*"*

9.2.2. **SRPC** has suggested inserting the following in the clause under Case-1:
Net VArh imported at S/S-B, while voltage < 97% = X3 Net VArh imported at S/S-B, while voltage > 103% = X4
(i) State-B pays to State-A for X3 and
(ii) State-A pays to State-B for X4

SRPC has suggested inserting the following in the clause under Case-2:
"Net VArh imported at S/S-A, while voltage < 97% = X1 Net VArh imported at S/S-A, while voltage > 103% = X2
(i) State-A pays to State-B for X1 and
(ii) State-B pays to State-A for X2"

9.2.3. **NHPC** has suggested that no payment shall be made for reactive compensation whether X1 is greater than X3 or vice versa, which may be reviewed.

9.3. Analysis and Decision

The provision as proposed in the Draft Regulations has been removed since it was found redundant. A new subclause (e) has been inserted under Clause (1) as follows:

“1(e) For any interconnecting line between two states, owned by the States, the interface points shall be treated in terms of this Regulation for the purpose of reactive power charges.”

10. Annexure - 4 (Clause 3 (c))

10.1. Commission’s Proposal

10.1.1. The Commission had proposed the following in Clause 3 (c) of the Draft Regulations:

“(c) The regional entities who have to receive the money on account of VAR charges would then be paid out from the regional Deviation and Ancillary Service Pool Account, within two (2) working days from the receipt of payment in the Deviation and Ancillary Service Pool Account.”

10.2. Comments have been received from POSOCO and SRPC

10.2.1. **POSOCO** has suggested replacing “Deviation and Ancillary Service Pool Account” with “Regional Reactive Pool Account”. POSOCO has also suggested adding the following provision to the clause,

“Provided that in case of any shortfall towards payment of VAr charges, surplus in the Regional Deviation and Ancillary Service Pool Account shall be used.”

10.2.2. **SRPC** has commented that payment to and from and may be made reactive pool account, therefore SRPC has suggested amending the clause as below:

“… receipt of payment in the <u>reactive pool account.”</u>

10.3. Analysis and Decision

10.3.1. Considering suggestions of POSOCO and SRPC, ‘Deviation and Ancillary Service Pool Account’ have been replaced with ‘Pool Account’ and the definition of ‘Pool Account’ has been inserted in definitions as follows:

“‘Pool Account’ means Deviation and Ancillary Service Pool Account as defined in the DSM Regulations, where the following transactions shall be accounted:

i. deviations and ancillary services
ii. reactive energy exchanges
iii. congestion charge;”

10.3.2. The Commission has noted the suggestions of the stakeholders

10.3.3. Clause 2 (c) of Annexure - 4 of the 2023 Grid Code Regulations has been modified as follows:

“(c) The regional entities who have to receive the money on account of VAR charges would then be paid out from the regional Pool Account, within two(2) working days from the receipt of payment in the Pool Account.”

11. Annexure - 5 (Clause 2 (1)(b)(ii))

11.1. Commission’s Proposal

11.1.1. The Commission had proposed the following in Clause 2 (1)(b)(ii) of the Draft Regulations:

“2. Role of Entities

(1) QCA or Renewable Energy Generating Station or Lead Generator
…
(b) QCA (for the REGSs it is representing) or REGS (who are not represented through QCA) or Lead Generator shall undertake the following activities:
(ii) Provide to concerned RLDC, Available Capacity, Day ahead forecast (based on their own forecast or on the forecast done by RLDC) and Schedule as per Appendix-II through web-based application maintained by RLDCs."

11.2. Comments have been received from RE Connect Energy

11.2.1. **RE Connect Energy** has suggested that, as per the provisions of the existing CERC regulations, the QCAs/REGS can also submit up to 16 intra-day revisions of the schedules, hence it is proposed to amend the clause to:

"Provide to concerned RLDC, Available Capacity, Day ahead forecast <u>and subsequent intra-day revisions</u> (based on their own forecast or on the forecast done by RLDC) …."

11.3. Analysis and Decision

11.3.1. With regard to suggestions of RE Connect it is clarified that the entity providing the day ahead forecast and schedule shall also submit any revision to the schedule, and there is no need to add it separately. The draft regulation has been retained.

12. Annexure - 5 (Clause 2 (1)(b)(iv))

12.1. Commission's Proposal

12.1.1. The Commission had proposed the following in Clause 2 (1)(b)(vi) of the Draft Regulations:

"(vi) Undertake commercial settlement for deviation as per applicable Regulations issued by the Commission."

12.2. Comments have been received from SRPC

12.2.1. **SRPC** has commented that disputes between QCA and its Developers need to be settled among themselves or resorting to legal recourse, and at the RPC level it should not be reported or handled, therefore, SRPC has suggested adding the following to the clause:

> *"Further commercial settlement will be settled between QCA & generating stations being represented by QCA. All the payments as applicable Regulations issued by the Commission would be made by QCA irrespective of settlement issues between QCA and Generating Stations."*

12.3. Analysis and Decision

12.3.1. The provision of disputes shall be as per mutual agreement between QCA and generators.

12.3.2. The draft regulation has been modified as Annexure-6 Clause 1 (b)(vi) in the 2023 Grid Code Regulations as follows:

"(vi) Undertake commercial settlement for deviation as per applicable CERC Regulations."

13. Annexure - 5 (Clause 2 (1)(b)(vii))

13.1. Commission's Proposal

13.1.1. The Commission had proposed the following in Clause 2 (1)(b)(vii) of the Draft Regulations:

"(vii) Submit a copy of the agreement entered between QCA and generating stations authorizing QCA specific responsibilities on behalf of generating stations, to the concerned RLDC."

13.2. Comments have been received from RE Connect Energy

13.2.1. **RE Connect Energy** has suggested that, as the scope of work carried out by the QCAs is similar for all the RE generating plants served by it, it is suggested amending the clause to:

"Submit a copy of the consent letter issued by the renewable energy generator authorizing QCA to carry out specific responsibilities on behalf of generating stations, to the concerned RLDC. Also, an agreement shall contain many other business sensitive information in terms of price agreed between the QCA and the generator and is binding on both the parties involved, the consent letter shall suffice the requirement and can be submitted to RLDC by the QCA*."*

13.3. Analysis and Decision

13.3.1. With regard to suggestions of RE Connect, the draft regulation has been modified as Annexure-6 Clause 1 (b)(vii) in the 2023 Grid Code Regulations as follows.

"(vii) Submit a copy of the consent to the concerned RLDC wherein it is mentioned that QCA shall undertake all operational and commercial responsibilities on behalf of generating stations as per the CERC Regulations."

14. Annexure - 6 (Clause 1 (a))

14.1. Commission's Proposal

14.1.1. The Commission had proposed the following in Clause 1 (a) of the Draft Regulations:

"(1) METERING, ACCOUNTING AND SETTLEMENT SYSTEM:

a) At the Inter State Transmission System (ISTS) level, the basic principle followed is that all settlements for the energy scheduled before the fact are done directly between the sellers and the buyers, with the Regional Power Committee issuing the accounts specifying the quantum of energy scheduled. All deviations from the schedule are settled through a regulatory pool account maintained by RLDCs; a net settlement where only the deviation payments are handled.

b) The settlement system shall be transparent, robust, scale-able (multi buyer/seller, interconnection with lower and upper pool systems) and dispute-free with integrity & probity possible and usage of state of the art techniques. The settlement computation details, applicable charges and operation of different regulatory pool accounts shall be in accordance with various regulations of the Commission."

14.2. Comments have been received from NTPC

14.2.1. **NTPC** has suggested that the role of RPC in issuing various accounts may be clearly defined, and accordingly following may be as provided:

"RPC shall prepare monthly Regional Energy Account (REA), weekly unscheduled interchange account, reactive energy account, based on data processed by RLDC. RPC shall endeavour to provide monthly energy accounts at the earliest, in any case not later than 2nd day of succeeding month, to enable generators process energy bills in time. Further the following may also be provided that: The Energy accounting system shall be transparent, robust, scalable, and as far as feasible employ modern data processing tools and use standard reporting formats across different RPCs, compatible with standard ERP systems of generating utilities."

14.3. Analysis and Decision

14.3.1. The timeline for issuance of various accounts shall be as per the respective regulations and are not included in this Annexure. Further, the requirement of standardisation of formats of various accounts has been provided for in the Regulations.

14.3.2. The draft regulation has been modified as Annexure-7 Clause 1 (a) in the 2023 Grid Code Regulations as follows,

"(1) METERING, ACCOUNTING AND SETTLEMENT SYSTEM:

(a) At the Inter State Transmission System (ISTS) level, the basic principle followed is that all settlements for the energy scheduled before the fact are done directly between the sellers and the buyers, with the Regional Power Committee issuing the Accounts specifying the quantum of energy scheduled. All deviations from the schedule are settled through a regulatory Pool Account maintained by RLDCs where only the deviation payments are handled.

(b) The settlement system shall be transparent, robust, scale-able (multi buyer/seller, inter connection with lower and upper pool systems) and dispute-free with integrity and probity and usage of state of the art techniques. The settlement computation details, applicable charges and operation of different regulatory Pool Accounts shall be in accordance with various regulations of the Commission. RPCs shall standardise the formats of various accounts. "

15. Annexure - 6 (Clause 1 (d))

15.1. Commission's Proposal

15.1.1. The Commission had proposed the following in Clause 1 (d) of the Draft Regulations:

"d. Energy Accounts inter-alia shall indicate Declared Capability of generating stations, Entitlements, Requisitions, Scheduled loss, Scheduled transactions GNA and T-GNA and actual Interchange."

15.2. Comments have been received from SRPC

15.2.1. **SRPC** has suggested the modification as below:

"For the entities being scheduled by RLDCs, energy Accounts inter-alia shall indicate Declared Capability of generating stations, scheduled transactions GNA and T-GNA and DSM Accounts, Reactive Power Accounts, SCED scheduled energy etc. and any other accounts to be issued under CERC Regulations."

15.3. Analysis and Decision

15.3.1. Considering the suggestions of SRPC, the draft regulation has been modified as Annexure-7 Clause 1 (d) in the 2023 Grid Code Regulations as follows,

"(d) Energy Accounts inter-alia shall indicate Declared Capability of generating stations, Entitlements, Requisitions, Scheduled loss, Scheduled transactions GNA and T-GNA and actual Interchange, Reactive Power Accounts, SCED scheduled energy <u>and any other accounts to be issued under CERC Regulations."</u>

16. Annexure - 6 (Clause 1 (f))

16.1. Commission's Proposal

16.1.1. The Commission had proposed the following in Clause 1 (f) of the Draft Regulations:

"f. Each regional entity (whether generator, RE Generator, captive Power Plant, OA customer connected at ISTS) in a region shall be a member of the regional pool and separately accountable for deviations. For cross border transactions, the Settlement Nodal Agency (SNA) as appointed by the Government of India would be a member of the regional pool."

16.2. Comments have been received from SRPC

16.2.1. **SRPC** has suggested adding QCA to the list of regional entities as QCA will be a member of pool.

16.3. Analysis and Decision

16.3.1. Suggestions of SRPC have been accepted. The draft regulation has been modified as Annexure-7 Clause 1 (f) in the 2023 Grid Code Regulations as follows,

"(f) Each regional entity (whether generator, RE Generator, <u>QCA (on behalf of generators)</u>, captive Power Plant, OA customer connected at ISTS) in a region shall be a member of the regional pool and separately accountable for deviations. For cross border transactions, the Settlement Nodal Agency (SNA) as appointed by the Government of India would be a member of the regional pool."

17. Annexure - 7 (Clause A (2))

17.1. Commission's Proposal

17.1.1. The Commission had proposed the following in Clause A (2) of the Draft Regulations

"Planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years(yearly)"

17.2. Comments have been received from CTU

17.2.1. **CTU** has suggested deleting the "ISTS-STU" from the clause. CTU commented that the ISTS Planning Procedure has already been prepared and available on CTU website.

In terms of regulation 5(4), STU shall undertake assessment and planning of the intra-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) import and export capability across ISTS and STU interface; and

(ii) adequate power transfer capability across each flow-gate.

17.3. Analysis and Decision

17.3.1. Considering suggestions of CTU and consequent changes in 'resource Planning Code', the reporting requirement for CTU has been modified.

17.3.2. The draft regulation has been modified as Annexure-5 Clause 1 (2) in the 2023 Grid Code Regulations as follows

"Transmission resource adequacy assessment
Self-audit Report (By 31st July of every year)"

sd/-	**sd/-**
(Arun Goyal)	**(Jishnu Barua)**
Member	**Chairperson**

List of Stakeholders who submitted written Comments/Suggestions:

Sl. No.	Name of the Stakeholder	Short form
1	AD Hydro Power Limited	ADHPL
2	Adani Green Energy Ltd.	AGEL
3	Adani Power MuL	APMuL
4	AP Transco	AP Transco
5	Association of Power Producers	APP
6	Bharat Aluminum Company Limited	BALCO
7	Bhakra Beas Management Board	BBMB
8	BSES Yamuna Power Ltd.	BYPL
9	Captive Power Producers Association	CPPA
10	CESE Ltd	CESC
11	Central Transmission Utility	CTUIL
12	DANS Energy Pvt Ltd	Dans Energy
13	Dhariwal Infrastructure Limited	Dhariwal
14	Directorate of Energy, HP Govt	DoE HP
15	Damodar Valley Corporation	DVC
16	Enel Green Power India Private Limited	Enel
17	GE Renewable	GE
18	Greenko Energies Private Limited	Greenco
19	GRIDCO Limited	GRIDCO
20	HVPN Haryana	HVPN
21	Hero Future Energy	Hero
22	SLDC Himachal Pradesh	SLDC HP
23	Hitachi Energy	Hitachi
24	HPSEB Ltd.	HPSEB
25	IEEMA -Copper alliance	IEEMA
26	Indian Energy Exchange	IEX
27	IIT Bombay (Sh. Zakir H Rather)	IITB
28	IWPA-wind association	IWPA
29	Jindal India Thermal Power Limited	JITPL
30	Kerala SEB	KSEBL
31	Karnataka Power Transmission Corp. Ltd.	HPTCL
32	Lawrence Berkeley National Lab (LBN Lab)	LBN

33	MB Power (Madhya Pradesh) Ltd.	MBMPL
34	MP Power Management Company Ltd.	MPPMCL
35	Maharashtra State Electricity Distribution Co. Ltd.	MSEDCL
36	Nabha Power Limited	Nabha
37	NERPC	NERPC
38	NHPC Ltd.	NHPC
39	Nuclear Power Corp. of India Ltd.	NPCIL
40	NTPC Ltd.	NTPC
41	National Solar Energy Federation of India	NSEFI
42	NTPC Vidyut Vyapar Nigam Limited	NVVN
43	O2 Power	O2 Power
44	ONGC Tripura Power Company	OTPC
45	Panaaya	Panaaya
46	Power Company of Karnataka Ltd	PCKL
47	POSOCO	POSOCO
48	Powergrid Corporation of India Ltd.	PGCIL
49	Prayas Energy Group	Prayas
50	PTC India Ltd	PTC
51	Punjab State PCL	PSPCL
52	Punjab Water Resource Department	PWSD
53	Power Exchange India Ltd.	PXIL
54	RE Connect Energy	RECONNECT
55	ReNew Power Private Limited	RENEW
56	Solar Energy Corporation of India Ltd.	SECI
57	Sembcorp Energy India Ltd.	Sembcorp
58	Sh. Anshuman	Sh. Anshuman
59	Sh. Ravinder	Sh. Ravinder
60	Siemens Limited	Siemens
61	SJVN Ltd.	SJVN
62	SLDC Odisha	SLDC Odisha
63	SRPC	SRPC
64	Statkraft Market Private Ltd.	Statcraft
65	Sterlite Power Transmission Limited	Sterlite
66	Tata Power	Tata Power
67	THDC India Limited	THDC
68	Torrent Power Limited	Torrent
69	Transmission Corporation of Telangana	TSTRANSCO

70	UPSLDC	UPSLDC
71	Wartsila	Wartsila
72	West Bengal State Electricity Distribution Company Ltd.	WBSEDCL
73	Wind Independent Power Producers Association	WIPPA
74	WRPC	WRPC
75	World Bank group	World Bank group

List of Stakeholders who made submissions during the Public Hearing

Sl. No.	Name of the Stakeholder	Short Form
1	POSOCO	POSOCO
2	Central Transmission Utility of India Ltd.	CTUIL
3	Gridco, Odisha	GRIDCO
4	Power Company of Karnataka Ltd	PCKL
5	Damodar Valley Corporation	DVC
6	NTPC Limited	NTPC
7	SJVN Limited	SJVN
8	Bhakhra Beas Management Board	BBMB
9	ONGC Tripura Power Company	OTPC
10	Powergrid Corporation of India Ltd.	PGCIL
11	Sterlite Power Transmission Limited	Sterlite
12	Hitachi Energy India Limited	Hitachi
13	Prayas (Energy) Group	Prayas
14	India Energy Storage Alliance	IESA
15	Indian Energy Exchange	IEX
16	Power Exchange India Ltd.	PXIL
17	Reliance Industries Limited	RIL
18	M. P. Power Management Company Limited	MPPMCL
19	Rajasathan Rajya Vidyut Prasaran Nigam Limited	RVPNL
20	NHPC Limited	NHPC
21	UPSLDC Lucknow	UPSLDC