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অসম ৰাজপত্ৰ

সত্যমেৱ জয়তে

# THE ASSAM GAZETTE

অসাধাৰণ

EXTRAORDINARY

প্ৰাপ্ত কৰ্ত্তৃত্বৰ দ্বাৰা প্ৰকাশিত

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GOVERNMENT OF ASSAM

ORDERS BY THE GOVERNOR

ASSAM ELECTRICITY REGULATORY COMMISSION

## NOTIFICATION

The 9th December, 2024

**No. AERC. 963/2024/23.-** In exercise of powers under Sections 181 of the Electricity Act, 2003, read with Section 86 (1) (h) and all powers enabling it in that behalf, the Assam Electricity Regulatory Commission hereby frames the following Regulations to replace and repeal the Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2018, namely;

**1) Short title, commencement and interpretation: -**

a) These Regulations may be called the Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2024.

b) These Regulations shall be applicable to all intra-State Transmission System participants, including

i. The State Transmission Utility, State Load Despatch Centre and Transmission Licensees

ii. Generating Stations including Captive Generators, connected to intra State Transmission System

iii. Distribution Licensees connected with intra State Transmission System

iv. EHV Consumers of Distribution Licensee directly connected to intra State Transmission System

v. Open access customers availing open access on intra state Transmission system

vi. Qualified Co-ordination Agencies, Renewable Energy Management Centres, and Power Exchanges

vii. Any other person connected to and/or user of intra state Transmission system, not specified above.

c) These Regulations extend to the whole State of Assam.

d) Anything not covered in these regulations shall be as per the Indian Electricity Grid Code, 2023 and its amendments thereof.

e) These Regulations shall come into force with effect from 1st of April, 2025.

# PART-I
# GENERAL CODE
## CHAPTER-1: GENERAL

### 1.1. INTRODUCTION

The Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2024 (hereinafter referred as State Grid Code or SGC) lays down the rules, guidelines and standards to be followed by various agencies and participants in the Intra-State transmission system (InSTS) to plan, develop, maintain and operate the intra-State transmission system, a part of North Eastern Regional Grid System, in most efficient, reliable, economic and secure manner, while facilitating a healthy competition in the generation and supply of electricity.

### 1.2. OBJECTIVES

The State Grid Code brings together a single set of technical and commercial rules, encompassing all the Utilities connected to/or using the intra-State transmission system (InSTS) and provides the following:

a) Documentation of the principles and procedures which define the relationship between the various Users of the intra-State transmission system (InSTS)and State Load Despatch Centre, concerned RLDC & NLDC.

b) Facilitation of the operation, maintenance, development and planning of economic and reliable State Grid.

c) Facilitation for beneficial trading of electricity by defining a common basis of operation of the InSTS, applicable to all the Users of the InSTS.

d) Facilitation of the development of Renewable Energy sources by specifying the technical and commercial aspects for integration of these sources into the Grid

### 1.3. SCOPE

a) All users such as Generating Companies including Captive Power Plants, IPPs & RE Generators, Distribution Companies, Open Access Customers, EHV consumers etc. that are connected with and / or utilize the State Grid are required to abide by the principles and procedures as laid down in the State Grid Code in so far as they apply to that user.

b) This code shall also apply for the Intra-State transmission of electricity.

c) STU, SLDC, Transmission licensees and all Users shall abide by this code to the extent it applies to them.

d) This State Grid Code shall not affect the obligations of the STU, SLDC and Users as laid down under the Indian Electricity Grid Code notified by CERC, and/or the Electricity Act, 2003 and rules and regulations made there under.

e) In case of any inconsistency between IEGC and the State Grid Code, the provision of IEGC shall prevail specifically for inter-state transactions and operations involving cross-border grid elements, unless otherwise provided by the Commission.

f) In case of any inconsistency between CEA Grid Standards and the State Grid Code, the provision of CEA Grid Standards shall prevail.

## 1.4. STRUCTURE OF GRID CODE

The Grid Code has been divided into following parts:

**I. Management of Code**

This part is intended to ensure that all other chapters of the Grid Code work together in the management of the Grid Code and establishment of a procedure for review of Grid Code to cater to inadvertent omissions and the modifications needed from time to time.

**II. Planning Code**

Planning Code includes:

a) **Resource Planning** covers integrated resource planning including demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment, required for secure grid operation.

b) **System Planning** specifying the procedures to be applied by STU in the planning and development of the State Transmission System and by other Users connected or seeking connection to the State Transmission System. This chapter deals with procedure to be followed by STU in the development of the EHV Transmission System in the long-term taking into account the requirements for new connection of generation and demand.

c) **Connection Conditions** specifying the technical requirements and standards to be complied by STU and other Users connected or seeking connection to the State Transmission System.

d) **Commissioning and Commercial Operation Code** covers aspects related to drawl of startup power from the grid and injection of infirm power into the grid, trial run operation, documents and tests required to be furnished before declaration of COD and requirements for declaration of COD.

## III. Load Despatch & System Operation Code

Load Despatch & System Operation Code includes:

a) **Operational Planning Code**: Specifies the conditions under which STU shall operate the State Transmission System, the Generating Companies shall operate their plants and the Distribution Licensees shall operate their Distribution Systems in so far as necessary to protect the security and quality of supply and safe operation of the State Transmission System under both normal and abnormal operating conditions.

b) **Security Code** describes the general security aspects to be followed by Intra-State Transmission System Users for grid security and safety of electrical equipment.

c) **Schedule and Despatch Code**: Specifies the principles relating to the scheduling, injection and drawal of power by the Users of the Intra-state Transmission System and the modalities for exchange of information and sets out the responsibilities of each User by Discoms to meet State demand and Drawal allocation.

d) **Frequency and Voltage Management Code:** Describes the method by which all Users of the State Transmission System shall co-operate with SLDC and STU in contributing towards effective control of the system frequency and managing the EHV voltage of the State Transmission System.

e) **Monitoring of Generation and Drawal Code:** Defines the responsibilities of all SSGS, IPPs, JVs and REGS in the monitoring of Generating Unit reliability and performance, and STU's/ Discoms' compliance towards improving system performance and observing grid discipline.

f) **Outage Planning**: Specifies the procedures relating to co-ordination among Users, STU, Generating Stations and Distribution Licensees in case of outages.

g) **Contingency Planning Code:** Describes the steps to be followed in the recovery process by all Users in the event of total or partial blackouts of the State Transmission System or the Regional Transmission System.

h) **Cross Boundary Safety** chapter sets down the requirements for maintaining safe working practices associated with inter user boundary operations and lays down the procedure to be followed when work is required to be carried out on electrical equipment that is connected to another User's system.

**IV. Protection Code**

Protection Code specifies the protection protocol, protection settings and protection audit plan of electrical systems to be adopted in order to safeguard the State Transmission System and Users' System from faults.

**V. Metering Code**

Metering Code specifies the minimum operational and commercial metering to be provided for each User. It also sets out the requirement and procedures for metering.

**VI. Cyber Security**

Cyber Security deals with measures to be taken to safeguard the State grid from spyware, malware, cyber-attacks, network hacking, procedure for security audit from time to time, upgradation of system requirements and keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements.

**VII. Data Registration Code**

This contains the details of all the data required by STU, which is to be provided by the Users and vice versa.

**1.5. INTERPRETATION**

In the interpretation of this Code, unless the context otherwise requires:

(i) words in the singular or plural term, as the case may be, shall also be deemed to include the plural or the singular term, respectively;

(ii) the headings are inserted for convenience and may not be taken into account for the purpose of interpretation of this Grid Code;

(iii) references to the statutes, regulations or guidelines shall be construed as including all statutory provisions consolidating, amending or replacing such statutes, regulations or guidelines, as the case may be.

**1.6. GENERAL REQUIREMENTS**

The Grid Code contains procedures to permit equitable management of day-to-day technical situations in the Power System, taking into account a wide range of operational conditions likely to be encountered under both normal and abnormal circumstances. It is nevertheless necessary to recognize that the Grid Code cannot predict and address all possible operational conditions.

Users must therefore understand and accept that STU in such unforeseen circumstances may be required to act decisively to discharge its obligations as STU. All generators within the purview of SLDC and Distribution Licensees shall provide such reasonable co-operation and assistance as STU may request in such circumstances.

### 1.7. CODE RESPONSIBILITIES

In discharging its duties under the Grid Code, STU has to rely on information, which Users supply regarding their requirements and intentions.

STU shall not be held responsible for any consequences that arise from its reasonable and prudent actions on the basis of such information.

### 1.8. CONFIDENTIALITY

Under the terms of the Grid Code, STU will receive information from Users relating to their intentions in respect of their Generation or Supply businesses.

STU shall not, other than as required by the Grid Code, disclose such information to any other person without the prior written consent of the provider of the information.

### 1.9. DISPUTE SETTLEMENT PROCEDURES

In the event of any dispute regarding interpretation of any part of the Grid Code provision between any Users and STU, the matter may be referred to the Commission for its decision. The Commission's decision shall be final and binding.

In the event of any conflict between any provision of the Grid Code and any contract or agreement between STU and Users, the provision of the Grid Code will prevail.

### 1.10. COMMUNICATION BETWEEN STU AND USERS

All communications between STU and Users shall be in accordance with the provision of the relevant section of the Grid Code and shall be made to the designated nodal officer appointed by STU.

Unless otherwise specifically required by the Grid Code all communications shall be in writing, save that where operation time scales require oral communication, these communications shall be confirmed in writing as soon as practicable.

The voice shall be recorded at SLDC and such record shall be preserved for a reasonable time to be decided.

### 1.11. PARTIAL INVALIDITY

If any provision or part of a provision of the Grid Code should become or be declared unlawful for any reason, the validity of all remaining provisions or parts of provisions, of the Grid Code shall not be affected.

### 1.12. DIRECTIVE

State Government may issue policy directives in certain matters as per the Electricity Act 2003. STU shall promptly inform the Commission and all Users of the requirement of such directives.

### 1.13. CONSISTENCY BETWEEN GRID CODE AND EXISTING CONNECTION AGREEMENTS

a) This Grid Code applies to:

   (i) All connection agreements made before and after the Code commencement date;

(ii) All requests to establish connection or modify an existing connection after the Code commencement date.

b) This Grid Code is neither intended to, nor is it to be read or construed as having the effect of:

(i) altering any of the terms of an existing connection agreement; or

(ii) altering the contractual rights or obligations of any of the parties under the existing connection agreement as between those parties; or

(iii) relieving the parties under any such connection agreement of their contractual obligations under such an agreement; or

(iv) Notwithstanding the provisions of sub-clauses (i) through (iii) above, if any obligation; imposed or right conferred on a User or Transmission Licensee by this Code is inconsistent with the terms of an existing connection agreement to which this Code applies and the application of the inconsistent terms of the connection agreement would adversely affect the quality or security of network service to other intra State transmission system Users, the parties to the connection agreement must observe the provisions of this Code as if they prevail over the connection agreement to the extent of the inconsistency.

## 1.14. COMPATIBILITY WITH INDIAN ELECTRICITY GRID CODE

This Grid Code is prepared such that it is consistent/ compatible with the IEGC, 2023 and its amendments.

The Assam Grid Code shall be reviewed and revised to make it consistent/ compatible in accordance with National Grid Code having regard to Grid Standards as and when specified by the Central Electricity Regulatory Commission under section 79(1) (h) of the Electricity Act, 2003.

## CHAPTER 2: DEFINITIONS

| Sl.No. | Particulars | Definition |
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| 1 | Act | means the Electricity Act, 2003 (Central Act No. 36 of 2003); |
| 2 | Active Energy | Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, and being the integral of the instantaneous power with respect to time, measured in units of watt hours or standard multiples thereof |
| 3 | Active Power | Active Power means the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof. |
| 4 | AERC | AERC means "Assam Electricity Regulatory Commission", also referred as the "Commission" |
| 5 | Agency | Agency means the utilities that utilize the State Grid |
| 6 | ADMS | Automatic Demand Management System |
| 7 | 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; |
| 8 | Ancillary Services | in relation to power system (or grid) operation, means the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in the AERC(Ancillary Services) Regulations, 2024 and its amendments thereof. |
| 9 | Ancillary Services Regulations or AS Regulations | Means the Assam Electricity Regulatory Commission (Ancillary Services) Regulations, 2024 and its amendments. |
| 10 | Apparatus | Electrical apparatus and includes all machines, fittings, accessories and appliances in which conductors are used. |
| 11 | Apparent Energy | Means the integral of the Apparent Power with respect to time. It is measured in Volt Ampere hour and standard multiple thereof. |
| 12 | Apparent Power | Means the product of voltage and current measured in units of volt amperes and standard multiples thereof. |
| 13 | Appendix | An Appendix to a section of the Grid Code |

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| 14 | Area Control Error or ACE | shall have the same meaning as defined in IEGC, 2023 and amendment thereof |
| 15 | Area of Supply | Area within which a distribution licensee is authorised by his license to supply electricity. |
| 16 | Associated Transmission System or ATS | shall have the same meaning as defined in the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022 and amendments thereof until the AERC (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2024 comes into effect; |
| 17 | Automatic Generation Control or AGC | means a mechanism that automatically adjusts the generation of a control area to maintain its interchange schedule plus its share of frequency response; |
| 18 | Automatic Voltage Regulator or AVR | means a continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals; |
| 19 | Auxiliary Energy Consumption | shall have the same meaning as defined in the AERC (Multi Year Tariff) Regulations, 2024 and its subsequent amendments |
| 20 | Auxiliaries | All the plant and machinery required for the Generating Unit's functional operation that do not form part of generating unit. |
| 21 | Authority | Means the Central Electricity Authority (CEA) as defined in the Act |
| 22 | Available Transfer Capability or ATC | means the available power transfer capability of inter-control area transmission system available for scheduling transactions (through long term access, medium term open access and short term open access) in a specific direction, taking into account the network security. Mathematically, ATC is the Total Transfer Capability less Transmission Reliability Margin; |
| 23 | Availability | shall have the same meaning as defined in the AERC (Multi Year Tariff) Regulations, 2024 and its subsequent amendments |
| 24 | ABT | Availability Based Tariff |
| 25 | Available Capacity | shall have the same meaning as defined in the AERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 and amendments thereof; |
| 26 | Backing Down | SLDC instructions or NERLDC instructions conveyed through SLDC for reduction of generation from generating unit under abnormal conditions such as high frequency, low system demand or network constraints; |

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| 27 | Beneficiary | means a person who has a share in a Generating Station as defined in IEGC |
| 28 | Bilateral Transaction | means a transaction for exchange of energy (MWH) between a specified buyer and a specified seller, directly or through a trading licensee or discovered at Power Exchange through anonymous bidding 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 during a specified period: |
| 29 | Blackout State | means a condition at a specific time where a part or all the operations of the power system have got suspended; |
| 30 | Black Start Procedure | means the process of recovery from a total or partial blackout of the Regional/State Grid.; |
| 31 | Breakdown | An occurrence relating to equipment of supply system which prevents its normal functioning |
| 32 | Bulk Consumer | shall have the same meaning as defined in CEA Technical Standards for Connectivity : |
| 33 | Buyer | means a licensee or consumer or captive user or company located within the State, receiving power by using the State-grid including such system when it is used in conjunction with inter-state transmission system and whose scheduling and/or metering and energy accounting is coordinated by the SLDC in accordance with the AERC Regulations; |
| 34 | Captive Generating Plant or Captive Power Plant or CPP | For the purpose of Grid Code, a Power Station that is primarily operated to meet a captive demand and is connected to State Grid but not supplying power to the Grid under normal circumstances. |
| 35 | CBIP | Central Board of Irrigation and Power |
| 36 | CEA Grid Standards | means the Central Electricity Authority (Grid Standards)<br>Regulations, 2010 and amendments thereof; |
| 37 | CEA Technical Standards for Communication | means the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020 and amendments thereof; |
| 38 | CEA Technical Standards for Connectivity | means the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and amendments thereof; |
| 39 | CEA Technical Standards for Construction | means the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and amendments thereof; |
| 40 | Central Commission | means the Central Electricity Regulatory Commission (CERC) referred to in sub-section (1) of Section 76 of the Act; |

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| 41 | Central Generating Station | means the generating station owned by a company owned or<br>controlled by the Central Government; |
| 42 | Central Transmission Utility or<br>CTU | means any government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act; |
| 43 | Cold Start | in relation to steam turbine means start up after a shutdown period exceeding 72 hours (turbine metal temperatures below approximately 40% of their full load values); |
| 44 | Collective Transaction | Collective Transaction means a set of transactions discovered in power exchange through anonymous, simultaneous competitive bidding by buyers and sellers; |
| 45 | Commission | means the Assam Electricity Regulatory Commission; |
| 46 | Communication System | shall have the same meaning as defined in the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017 and amendments thereof: |
| 47 | Congestion | means a situation where the demand for transmission capacity or power flow on any transmission corridor exceeds its Available Transfer Capability; |
| 48 | Connectivity Agreement | An agreement between STU and a User setting out the terms relating to the Connection to and/or use of the State Transmission System. |
| 49 | Connection Conditions | The technical conditions to be complied with by any User having a Connection to the State Transmission System as laid down in: "Connection Conditions" of the Grid Code. |
| 50 | Connection Point | Means a point at which a Plant and/or Apparatus connects to the Transmission or Distribution system. |
| 51 | Connectivity | means the state of getting connected to the intra-State transmission system by a generating station including a captive generating plant, a bulk consumer or an Inter-State Transmission licensee, in terms of the GNA Regulations; |
| 52 | Consumer | Consumer shall have the same meaning as defined in the Act |
| 53 | Control Area | means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas and contributes to regulation of frequency as specified in these regulations; |

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| 54 | Control Centre | includes NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOM LDC including main and backup Centres, as applicable; |
| 55 | Date of Commercial Operation or COD | shall have the same meaning as specified under Regulation 27 of these regulations; |
| 56 | DCC | DCC means Distribution Control Centre |
| 57 | Declared Capacity or DC | in relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in the Grid Code or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification as per provisions of these regulations; |
| 58 | Demand | means the demand of active power in MW and reactive power in MVAr unless otherwise stated; |
| 59 | Demand Response | means reduction in electricity usage by end customers from their normal consumption pattern, manually or automatically. The same is done in response to high DSM charges being incurred by the State due to overdrawal at low frequency, or in response to congestion charges being incurred for creating transmission congestion, or for alleviating a system contingency, for which such consumers could be given a financial incentive or lower tariff; |
| 60 | 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; |
| 61 | DSM Regulations | means the AERC (Deviation Settlement Mechanism and Related Matters) Regulations 2024 and amendments thereof; |
| 62 | Deviation | Deviation in a time-block for a Seller means its total actual injection minus its total scheduled generation. Deviation for a Buyer means its total actual drawal minus its total scheduled drawal. |
| 63 | df / dt Relay | A relay which operates when the rate of change of system frequency (over time) goes higher than a specified limit and initiates load shedding |
| 64 | Disconnection | The act of physically separating a User's or EHV Consumer's electrical equipment from the State Transmission System. |
| 65 | Distribution System | The system of wires and associated facilities between the delivery points on the transmission lines or the generating station connection and the point of connection to the installation of the consumers |

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| 66 | Disturbance Recorder or DR | means a device for recording the behavior of the pre-selected digital and analog values of the system parameters during an event; |
| 67 | Data Acquisition System or DAS | means a system for recording the sequence of operation in time, of the relays or equipment as well as the measurement of pre- selected system parameters; |
| 68 | Drawal Schedule | means the Ex-power plant MW that a Distribution Licensee or Open Access user is scheduled to receive from SSGS/ISGS including bilateral transaction from time to time under GNA and T-GNA; |
| 69 | Extra High Voltage (EHV) | Nominal voltage levels of higher than 33 kV. |
| 70 | EHV Consumer | A person to whom electricity is provided and who has a dedicated supply at 66 kV or above. |
| 71 | 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; |
| 72 | Energy Charge | means the energy charge for the generating stations whose tariffs are determined by the Commission under Section 62 of the Act. |
| 73 | Energy Storage System or ESS | in relation to the electricity system, means a facility where electrical energy is converted into any form of energy which can be stored, and subsequently reconverted into electrical energy and injected back into the grid; |
| 74 | Event | means an unscheduled or unplanned occurrence in the intra-state transmission system including faults, incidents and breakdowns; |
| 75 | Event Logging Facilities | means a device for recording the chronological sequence of operations, of the relays and other equipment; |
| 76 | Ex-Power Plant | means net MW or MWh output of a generating station, after deducting auxiliary consumption and transformation losses; |
| 77 | Fault Locator or FL | means a device provided at the end of a transmission line to measure or indicate the distance at which a line fault may have occurred; |
| 78 | Flat frequency control | means a mechanism for correcting ACE by factoring in only the frequency deviation and ignoring the deviation of net actual interchange from net scheduled interchange; |
| 79 | Flat tie-line control | means a mechanism for correcting ACE by factoring in only the deviation of net actual interchange from net scheduled interchange ignoring frequency deviation; |

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| 80 | Flexible Alternating Current Transmission System or FACTS | means a power electronics based system and other static equipment that provide control of one or more AC transmission system parameters to improve power system stability, enhance controllability and increase power transfer capability of transmission systems; |
| 81 | Flow-gate | means a group of parallel transmission line (s), outage of which may lead to cascade tripping or separation of systems or loss of generation complex or loss of load centre; |
| 82 | Forced Outage | means an outage of a generating unit or a transmission facility due to a fault or any other reasons which have not been planned; |
| 83 | Free Governor Mode of Operation | Means the mode of operation of governor where machines are loaded or unloaded directly in response to grid frequency i.e machine unloads when grid frequency is more than 50 Hz and loads when grid frequency is less than 50 Hz. The amount of loading or unloading is proportional to the governor droop. |
| 84 | Frequency Response Characteristics or FRC | Means automatic, sustained change in the power consumption by load or output of the generators that occur immediately after a change in the load-generation balance of a control area and which is in a direction to oppose any change in frequency. Mathematically it is equivalent to<br>FRC = Change in Power (ΔP) / Change in Frequency (Δf); |
| 85 | Frequency Response Obligation or FRO | means the minimum frequency response a control area has to provide in the event of any frequency deviation; |
| 86 | Frequency Response Performance or FRP | means the ratio of actual frequency response with frequency response obligation; |
| 87 | Frequency Stability | means the ability of the transmission system to maintain stable frequency in the normal state and after being subjected to a disturbance; |
| 88 | Force Majeure | Force Majeure refers to any event which is beyond the control of the persons involved, which they could not foresee or with a reasonable amount of diligence, could not have foreseen or which could not be prevented and which substantially affects the performance by person such being the following including but not limited to :-<br>a) Acts of God, natural phenomena, floods, droughts, earthquakes and epidemics;<br>b) Riot or civil commotion;<br>c) Grid failure not attributable to a person. |

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| 89 | Gate Closure | means the time at which the bidding for a specific delivery period closes at the power exchange and no further bidding or modification of already placed bids can take place for the said delivery period. |
| 90 | Generating Unit | means<br>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 ;<br>b) an inverter along with associated photovoltaic modules and other equipment in respect of generating station based on solar photo voltaic technology;<br>c) a wind turbine generator with associated equipment, in respect of generating station based on wind energy;<br>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; |
| 91 | GNA Regulations | means the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022 and subsequent amendments until the AERC (Connectivity and General Network Access to the intra-State Transmission System) Regulations comes into effect; |
| 92 | GNA Grantee | means a person who has been granted GNA or is deemed to have been granted GNA under GNA Regulations; |
| 93 | Governor Droop | in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from no load to full load; |
| 94 | Grid | The combination of the State Transmission System, Distribution System and Power Stations. |
| 95 | Grid Code / Code | "Grid Code" also referred as the Assam Electricity Grid Code/AEGC/Assam State Grid Code/State Grid Code means a set of principles and guidelines prepared in accordance with the terms of section 86 (1) (h) of the Electricity Act 2003. |
| 96 | Grid Standards | Grid Standards means the standards specified by the Authority under clause (d) of the Section 73 of the Act. |

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| 97 | Grid Contingencies | means abnormal operating conditions brought out by tripping of generating units, transmission lines, transformers or abrupt load changes or by a combination of the above leading to abnormal voltage and/or frequency excursions and/or overloading of network equipment. |
| 98 | Grid Disturbance | Grid Disturbance is the situation where disintegration and collapse of grid either in part or full take place in an unplanned and abrupt manner, affecting the power supply in a large area of the region. |
| 99 | Grid Code Management Committee (GCMC) | GCMC means the Committee set up under "Management of Grid Code" of the Grid Code. |
| 100 | Grid Security | means the power system's capability to retain a normal state or to return to a normal state as soon as possible. and which is characterized by operational security limits; |
| 101 | Grid Standards | The standards specified by CEA under clause (d) of the section 73 of the Electricity Act, 2003. |
| 102 | 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); |
| 103 | IE Rules | Indian Electricity Rules 1956 and its subsequent amendments |
| 104 | Independent Power Producer (IPP) | means a Power Station within the State, owned by a Generator who is not part of the State Generating Company (APGCL in case of Assam), STU or Central Sector Generation and is not classified as a CPP. |
| 105 | Indian Electricity Grid Code (IEGC) | means the set of principles and guidelines prepared in accordance with the terms of section 79 (1) (h) of the Electricity Act 2003 by the CERC. |
| 106 | Inertia | means the contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is coupled with the power system and synchronized to the frequency of the power system; |
| 107 | Infirm Power | means the electricity injected into the grid prior to the date of commercial operation of a unit of the generating station; |
| 108 | Inter Connecting Transformer (ICT) | means transformer connecting EHV lines of different voltage levels. |
| 109 | Intermediary Procurer | shall have the same meaning as defined in the Electricity (Amendment) Rules, 2022 |

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| 110 | Inter-State Generating Station or ISGS | means a Central owned /UMPP /other generating stations in which two or more than two states have a share and whose scheduling is to be coordinated by the RLDC; |
| 111 | Intra-State Generating Station or InSGS | means a State owned /UMPP /other generating stations in which only the state have share and whose scheduling is to be coordinated by the SLDC; |
| 112 | Inter-State Transmission System or ISTS | means any system for conveyance of energy by means of a main transmission line from territory of one state to another state and includes:<br>The conveyance of energy across the territory of an intervening state as well as conveyance within the state which is incidental to such inter-state transmission of energy.<br>The transmission of energy within the territory of a state on a system built, owned, operated and maintained by the CTU or by any agency/person under supervision and control of CTU; |
| 113 | InSTS | Intra-State Transmission System |
| 114 | Licensee | Licensee means a person who has been granted a license under section 14 of the Act |
| 115 | LILO | LILO means loop in loop out. |
| 116 | LBB | LBB means local breaker back-up. |
| 117 | Load | means the active, reactive or apparent power consumed by a utility/installation of consumer; |
| 118 | Load Crash | Sudden or rapid reduction of electrical load connected to a system that could be caused due to tripping of major transmission line(s), feeder(s), power transformer(s) or natural causes like rain etc. |
| 119 | Maximum Continuous Rating or MCR | means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters; |
| 120 | Merit Order | means the order of ranking of available electricity generation in ascending order from least energy charge to highest energy charge to be used for deciding despatch instructions to minimize the overall cost of generation; |
| 121 | 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 |
| 122 | Nadir Frequency | means minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss; |

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| 123 | NTPC | National Thermal Power Corporation Limited. |
| 124 | National Grid | means the entire inter-connected electric power network of the country; |
| 125 | National Load Despatch Centre or NLDC | means the National Load Despatch Centre established under sub-section (1) of Section 26 of the Act; |
| 126 | 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; |
| 127 | Net Drawal Schedule | means the drawal schedule of a State entity which is the algebraic sum of all its transactions through the intra-State transmission system at InSTS periphery after deducting the transmission losses; |
| 128 | Net Injection Schedule | means the injection schedule of a State entity which is the algebraic sum of all its transactions through the intra-State transmission system at InSTS periphery; |
| 129 | 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; |
| 130 | North-Eastern Region/ Region | Region comprising of the States and Union Territory of Arunachal Pradesh, Assam, Meghalaya, Manipur, Mizoram, Nagaland and Tripura |
| 131 | North-Eastern Regional Grid System | means power systems of SEBs/Utilities/IPP/CPPs of the States of the North-Eastern Region and of NTPC & PGCIL having integrated operation |
| 132 | NERPC | North Eastern Regional Power Committee |
| 133 | NERLDC | North Eastern Regional Load Despatch Centre (Grid India) |
| 134 | Off-Bar Declared Capability | means the difference between Declared Capacity and On-Bar Declared Capacity in MW; |
| 135 | On-Bar Declared Capacity | in relation to a generating station means the capability to deliver ex-bus electricity in MW from the units on-bar declared by such generating station in relation to any time block of the day or whole of the day, duly taking into account the availability of fuel and water and subject to further qualification in the relevant regulations; |
| 136 | On-Bar Installed Capacity | means the summation of name plate capacities or the capacities as approved by the Commission from time to time, of all units of the generating station in MW which are on- bar. In case of a combined cycle module of a gas or liquid fuel-based stations, the installed capacity of steam turbine shall be in proportion to the on-bar capacity of gas turbines of the module; |

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| 137 | Operation | Operation means a scheduled or planned action relating to the operation of a system. |
| 138 | Operating range | Operating range means the operating range of frequency and voltage as specified under the operating code. |
| 139 | Open Access | Open Access carries the same meaning as defined in the Act |
| 140 | Open Access Customer | This is as defined in the AERC(Terms and Conditions for Open Access) Regulations, 2024 and amendments thereof |
| 141 | Operation Co-ordination Sub-Committee or OCC | means a sub-committee of RPC which deliberates and decides the operational aspects of the regional grid; |
| 142 | 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; |
| 143 | Outage | In relation to a Generator/ Transmission/ Distribution facility, an interruption of power supply whether manually or by protective relays in connection with the repair or maintenance of the SSGS/Transmission facility or resulting from a breakdown or failure of the Transmission /Distribution facility/SSGS unit or defect in its Auxiliary system. |
| 144 | Peak Period | That period in a day when electrical demand is at its highest. |
| 145 | Planned Outage | An Outage in relation to a SSGS unit for Power Station Equipment or Transmission facility which has been planned and agreed by the beneficiaries and approved by the SLDC, in advance in respect of the year in which it is to be taken. |
| 146 | Pool Account | means Deviation and Ancillary Service Pool Account as defined in the DSM Regulations, where the following transactions shall be accounted:<br>i. deviations and ancillary services<br>ii. reactive energy exchanges<br>iii. congestion charge; |
| 147 | Pooling Station | means the InSTS grid sub-station where pooling of generation of connected individual generating stations is done for interfacing with the next higher voltage level; |
| 148 | Power Grid/ PGCIL | The Power Grid Corporation of India Limited. |
| 149 | Power Station | An installation of one or more Generating Units (even when sited separately) owned and/or operated by the same SSGS and which may reasonably be considered as being managed as a single integrated generating complex. |

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| 150 | Power System | shall have the same meaning as defined in sub-section (50) of Section 2 of the Act |
| 151 | Primary Reserve | means the maximum quantum of power which will immediately come into service through governor action of the generator or frequency controller or through any other resource in the event of sudden change in frequency as specified in these regulations; |
| 152 | Protection Co-ordination Sub- Committee | means a sub-committee of RPC with members from all the regional entities which decides on the protection aspects of the regional grid; |
| 153 | PTW (Permit to Work) | Safety documentation issued to any person to allow work to commence on inter-user boundary after satisfying that all the necessary safety precautions have been established; |
| 154 | Qualified Coordinating Agency" or QCA | means the lead generator or any authorized agency on behalf of REGS (Renewable Energy Generating Station) or RHGS (Renewable Hybrid Generating Station) including Energy Storage Systems connected to one or more pooling station(s) for coordinating with concerned load despatch centre for scheduling, operational coordination and deviation settlement. QCA shall have the following purposes:<br>• Provide schedules with periodic revisions as per this regulation on behalf of all the Wind/Solar Generators connected to the pooling station(s),<br>• Responsible for metering, data collection / transmission, communication, coordination with DISCOMS, SLDC and other agencies.<br>• Undertake commercial settlement of all charges on behalf of the generators, including payments to the pool accounts through the concerned SLDC.<br>• Undertake de-pooling of payments received on behalf of the generators from the State Deviation and Ancillary Services Pool Account and settling them with the individual generators<br>• Undertake commercial settlement of any other charges on behalf of the generators as may be mandated from time to time.; |
| 155 | Ramp Rate | means rate of change of a generating station output expressed in %MW per minute; |
| 156 | Rate of Change of Frequency or *df/dt* | means the time derivative of the power system frequency which negates short term transients and therefore reflects the actual change in synchronous network frequency; |
| 157 | Reference contingency | means the maximum positive power deviation occurring instantaneously between generation and |

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| | | demand and considered for estimation of reserves; |
| 158 | Reactor | Reactor means an electrical facility specifically designed to absorb reactive power. |
| 159 | Regional Entity | means the entitiy which is in the RLDC control area and whose metering and energy accounting is done at the regional level; |
| 160 | Regional Power Committee or RPC | shall have the same meaning as defined under sub-section (55) of Section 2 of the Act. |
| 161 | Restorative State | means a condition in which control action is being taken to reconnect the system elements and to restore system load; |
| 162 | Regional Energy Account or REA | means account of energy and other parameters issued by the respective RPC for the purpose of billing and settlement of charges of ISGS and other users of the concerned region; |
| 163 | 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 CERC Sharing Regulations ; |
| 164 | Regional Grid | means the high voltage backbone system of inter-connected transmission lines, sub-stations and generating plants in a region; |
| 165 | Regional Load Despatch Centre or RLDC | means the Centre established under sub-section (1) of Section 27 of the Act; |
| 166 | Renewable Energy Generating Station or REGS | means a generating station based on a renewable source of energy with or without Energy Storage System and shall include Renewable Hybrid Generating Station; |
| 167 | Renewable Hybrid Generating Station or RHGS | means a generating station based on hybrid of two or more renewable source(s) of energy with or without Energy Storage System, connected at the same inter-connection point; |
| 168 | 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; |
| 169 | Resource Adequacy Framework | means Assam Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024 and amendments thereof |
| 170 | Rotational Load Shedding | Planned Disconnection of Customers on a Rotational basis during periods when there is a significant short fall of power required to meet the total Demand; |

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| 171 | Regional Transmission System | The combination of EHV electric lines and electrical equipment owned or operated by Power Grid / utilities; |
| 172 | SCADA | SCADA means Supervisory Control and Data Acquisition |
| 173 | SCED Account | means a bank account from where all payments to and from the generating station(s) on account of SCED schedules flows |
| 174 | SCED Compensation Charge | means the charge declared by a generating station other than the generating station whose tariff is determined by the Commission under Section 62 of the Act, for participation in SCED; |
| 175 | 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; |
| 176 | Secondary Reserve Ancillary Service or SRAS | means the Ancillary Service comprising SRAS-Up and SRAS- Down, which is activated and deployed through secondary control signals; |
| 177 | Secondary Reserve Ancillary Service Provider or SRAS Provider | means an entity which provides SRAS-Up or SRAS-Down service in accordance with Ancillary Service Regulations; |
| 178 | Security Constrained Economic Despatch or SCED | Means optimised despatch of generating units subject to operational and technical limits of generation and transmission facilities as specified in these regulations; |
| 179 | Security Constrained Unit Commitment or SCUC | means committing generating units while respecting limitations of the transmission system and unit operating characteristics as specified in these regulations; |
| 180 | Seller | means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with these regulations; |
| 181 | Settlement Nodal Agency or SNA | means the nodal agency as notified by Ministry of Power, Government of India for each neighboring country for settlement of grid operation related charges in terms of Central Electricity Regulatory Commission (Cross Border Trade of Electricity) Regulations, 2019 and amendments thereof; |
| 182 | Share | means percentage or MW entitlement of a beneficiary in an ISGS either notified by Government of India or agreed between the generating company and beneficiary through contracts and implemented through GNA or TGNA, as the case may be; |
| 183 | Shut Down | The condition of a Generating Unit where it is at rest |

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| | | or on barring gear isolated from grid or Transmission facility, which is at rest or isolated from Grid. |
| 184 | Spinning Reserve | Spinning Reserve means the capacities which are provided by devices including generating station or units thereof synchronized to the grid and which can be activated on the direction of the system operator and effect the change in active power. |
| 185 | SPS | SPS means special protection scheme. |
| 186 | Start up power | Start-up power is that which is required for initial start-up and commissioning of a new generating Unit as well as start-up after forced or planned outage of an existing generating Unit |
| 187 | State | The State of Assam. |
| 188 | State Entity | means an enitity located within the State, receiving or injectingpower by using the State-grid including such system when it is used in conjunction with inter-State transmission system and whose scheduling and/or metering and energy accounting is coordinated by the SLDC at the State level. |
| 189 | State Grid | means the entire inter-connected electric power network of the State; |
| 190 | State Load Despatch Centre or SLDC | means the Centre established under sub-section (1) of Section 31 of the Act, presently having its control room at Kahlipara is the apex body to ensure integrated operations of the power system in the state; |
| 191 | State Sector Generating Station (SSGS) | Any power station within the State, except the Inter-State Generating Station (ISGS) located within the State. |
| 192 | State Transmission System (STS) | The system of EHV electric lines and electrical equipment operated and/or maintained by STU or any Transmission Licensee for the purpose of the transmission of electricity between Power Stations, External Interconnections and the Distribution System. (also referred to as InSTS) |
| 193 | State Transmission Utility or STU | means the board or the government company specified as such by the concerned State Government under sub-section (1) of section 39 of the Act. Assam Electricity Grid Corporation Limited (AEGCL) has been notified as State Transmission Utility under section 39 of the Act by GoA; |
| 194 | SVC | SVC means Static VAR Compersator, i.e. an electrical facility designed for the purpose of generating or absorbing reactive power. |
| 195 | Synchronized | "Synchronized" means the state where connected alternating current systems, machines, or a combination of these operate at the same frequency, |

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| | | and where the phase angle displacements between voltages in them are constant or vary about a steady and stable average value. |
| 196 | System Constraint | means a situation in which there is a need to prepare and activate a remedial action in order to respect operational security limits; |
| 197 | System State | means the operational state of the power system in relation to the operational security limits which can be normal state, alert state, emergency state, extreme emergency state and restorative state; |
| 198 | Tariff Regulations | means the Assam Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2024 and subsequent amendments; |
| 199 | Technical Co-ordination Committee or TCC | means the sub-committee set up by the respective RPC to coordinate the technical and commercial aspects of the operation of the regional grid; |
| 200 | Tertiary Reserve | means the quantum of power which can be activated in order to take care of contingencies and to cater to the need for replacing secondary reserves; |
| 201 | Tie-line bias control | means a mechanism of correcting ACE by factoring in deviation of net actual interchange from net scheduled interchange as well as frequency deviation; |
| 202 | Time Block | means block of duration as specified by the Commission for which energy meters record values of specified electrical parameters with first time block starting at 00.00 Hours, presently of fifteen (15) minutes duration; |
| 203 | Total Transfer Capability or TTC | means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency; |
| 204 | Transmission Planning Criteria | means the criteria issued by CEA for transmission system planning; |
| 205 | Transmission Reliability Margin or TRM | means the amount of margin earmarked in the total transfer capability to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions; |
| 206 | Trial Operation or Trial Run | shall have the same meaning as specified in Regulation 6.5 or Regulation 6.6 of these regulations, as applicable; |

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| 207 | User | means and includes generating company, captive generating plant, energy storage system, transmission licensee including deemed transmission licensee, distribution licensee, solar park developer, wind park developer, wind-solar photo voltaic hybrid system, or bulk consumer which is or whose electrical plant is connected to the grid at voltage level 11 kV and above; |
| 208 | Unscheduled Generation | Any generation that is in violation of SLDC / NERLDC instructions and parameters described in relevant sections of the Grid Code. |
| 209 | VAR | VAR means Volt Ampere Reactive |
| 210 | Voltage Stability | means the ability of a transmission system to maintain steady acceptable voltages at all nodes in the transmission system in the normal situation and after being subjected to a disturbance; |
| 211 | WAMS | Wide Area Measurement System |
| 212 | Warm Start | means the start up after a shutdown period between 10 hours and 72 hours (turbine metal temperatures between approximately 40% to 80% of their full load values) in relation to steam turbine; |
| 213 | WS Seller | shall have the same meaning as defined in the AERC (DSM and Related Matters) Regulations, 2024, and its subsequent amendments. |

# CHAPTER 3: MANAGEMENT OF THE GRID CODE

## 3.1. Introduction

**3.1.1.** The State Grid Code (SGC) shall be specified by the Commission. Any amendment to SGC shall also be specified by the Commission only.

**3.1.2.** State Grid Code shall be reviewed by the Grid Code Management Committee at least once in every twelve (12) months or as may be directed by the Commission.

**3.1.3.** Upon completion of such review, the Grid Code Management Committee shall send a report to the State Transmission Utility providing information regarding:

a) Outcome of the review; and
b) Any proposed revisions to the State Grid Code.

**3.1.4.** The SLDC/STU shall send the report, referred in sub-Regulation (3) of this Regulation to the Commission.

**3.1.5.** The SGC and its amendments shall be finalized and notified adopting the prescribed procedure followed for Regulations issued by the Commission.

**3.1.6.** The requests for amendments to/ modifications in the SGC and for removal of difficulties shall be addressed to Secretary to the Commission, for periodic consideration, consultation and disposal.

**3.1.7.** Any dispute or query regarding interpretation of SGC may be addressed to Secretary to the Commission and clarification issued by the Commission shall be taken as final and binding on all concerned.

## 3.2 Objective

The objective of this section is to define the method of managing the Grid Code, submitting and pursuing of any proposed change to the Grid Code and the responsibilities of all Users to effect that change.

## 3.3 Roles and Responsibilities:

3.3.1 **SLDC :**

I. In accordance with section 32 of Electricity Act, 2003, the State Load Despatch Centre (SLDC) shall have following functions:

a. The State Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in a State.

b. The State Load Despatch Centre shall -

1. be responsible for optimum scheduling and despatch of electricity within a State, in accordance with the contracts entered into with the licensees or the generating companies operating in that State;
2. monitor grid operations;
3. keep accounts of the quantity of electricity transmitted through the State grid;

4. exercise supervision and control over the intra-State transmission system; and be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the State Grid Code.

II. In accordance with section 33 of the Electricity Act,2003, the SLDC in a State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in that State. Every licensee, generating company, generating station, sub-station and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Depatch Centre under sub- section (1) of Section 33 of the Electricity Act,2003.

III. The State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre.

IV. In case of inter-state bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the Central Electricity Regulatory Commission (Open Access in inter-state Transmission) Regulations, 2008, amended from time to time.

V. SLDC shall be manned by qualified and experienced engineers and professionals who are well acquainted with the State Transmission System and grid operations.

VI. Periodical Training shall be imparted to the personnel of the SLDC to update their skills in order to enable them to discharge their functions stipulated under the Indian Electricity Act.

VII. If any licensee, generating company or any other person fails to comply with the directions issued by SLDC, he shall be liable to penalty as stipulated under The Act.

VIII. Operation of State Deviation and Ancillary Services pool account, State Reactive Energy account, State Congestion Charge Account and other functions as directed by the Commission.

IX. In addition to above responsibilities SLDC shall undertake all the responsibilities specified by the Commission under various Regulations of the Commission from time to time.

3.3.2 **STU:**

I. Section 39 of the Electricity Act, 2003, outlines that the functions of the State Transmission Utility (STU) shall be –

a. to undertake transmission of electricity through intra-State transmission system:

b. to discharge all functions of planning and co-ordination relating to intra-state transmission system with-

1. Central Transmission Utility;
2. State Governments;

3. Generating companies;
4. Regional Power Committees;
5. Authority;
6. Licensees;
7. any other person notified by the State in this behalf;

c. to ensure development of an efficient, co-ordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centers;

d. to provide non-discriminatory open access to its transmission system for use by -
1. any licensee or generating company on payment of the transmission charges; or
2. any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42 of the Act, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.

II. Until a Government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre.

III. In addition to above responsibilities STU shall under all the responsibilities specified by the Commission under various Regulations of the Commission from time to time.

3.3.3 **DCC (Distribution Control Centre):**

Distribution Licensees operating in the State shall establish their DCC (DCC) to carry out the operating directives of SLDC and assist SLDC for safe and integrated operation of the concerned distribution network. DCC must have a 24 x 7 control room with adequate numbers of qualified manpower. DCC shall be responsible for:

I. Data acquisition and transfer to SLDC
II. Supervisory control of load in their respective area
III. Assist SLDC to ensure safe and integrated operation of the power system of the State;
IV. Assist SLDC for monitoring grid operations;
V. Carry out the real-time instructions of SLDC for safe and integrated operation of the State grid
VI. Maintain the drawal and/ or injection schedule as finalized by SLDC;
VII. DCC shall comply with all the directives given by SLDC and provide all relevant information as and when required by the SLDC.

**3.4 Grid Code ManagementCommittee (GCMC):**

3.4.1 A Grid Code Management Committee shall be constituted by the State Load Dispatch Center with the consent of the commission within thirty (30) days from the date of notification of these Regulations.

3.4.2 The Grid Code Management Committee shall be responsible for the following matters, namely-

I. facilitating the implementation of these Regulations and the rules and procedures developed under the provisions of these Regulations;

II. assessing and recommending remedial measures for issues that might arise during the course of implementation of provisions of these Regulations and the rules and procedures developed under the provisions of these Regulations;

III. to assess and advice to the commission, the necessary amendments/changes required to be brought, in these regulations for smooth operation of the power sector and in the interest of overall compliance to the provisions of the Electricity Act 03 and;

IV. to review and ensure compliance of roles & responsibilities of various agencies/entities as specified in the Code;

V. to review and to take follow up action on the recommendations of functional committees formed under this Code;

VI. such other matters as may be directed by the Commission from time to time.

3.4.3 The Grid Code Management Committee shall comprise of the following members & Chairman:

I. Managing Director of State Transmission Utility shall be the Chairperson;

II. Chief Executive of the SLDC shall be the Convenor;

III. One member from State Transmission Utility;

IV. One member to represent state generating companies

V. One member from each class of generating companies in the State, other than state generating companies.

VI. One member to represent the Transmission Licensees in the State, other than the State Transmission Utility;

VII. One member each to represent the state-owned Distribution Licensees in the State;

VIII. One member to represent the privately-owned Distribution Licensees, if any

IX. One member to represent the Electricity Traders in the State;

X. One member to represent the Open Access Customers;

XI. One member to represent the North Eastern Regional Load Despatch Centre; and

XII. One member to represent the North Eastern Regional Power Committee

XIII. Such other persons as may be nominated by the Commission.

3.4.4 Provided further that the State Transmission Utility shall, in coordination with State Load Despatch Centre, provide necessary support to facilitate smooth functioning of the Grid Code Management Committee. The members of the GCMC shall be selected as follows:

I. The member referred to in Regulation 3.4.3 (II) above shall be the head of State Load Despatch Centre;

II. the concerned technical person of State Transmission Utility, having the responsibility of looking after Operation & Maintenance, System Studies & System Protection activities of State Transmission Utility shall be the member referred to in clause 3.4.3 (III) of the above Regulation;

III. the members referred to in clauses other than 3.4.3 (II) & (III) above, shall be nominated by their respective organizations, which organizations will be selected in rotation from among all such organizations in the State.

IV. The term of each such member, selected in rotation, shall be three (3) years. Provided that the members nominated by each of the organization to the above Committee shall be holding a senior position in their respective organization.

3.4.5 The Rules to be followed by the Committee in conducting their business shall be formulated by the Committee themselves and shall be approved by the AERC. The Committee will meet at least once in three months.

3.4.6 **Functional Committees under Grid Code Management Committee**

I. The STU is responsible for servicing/implementation of Grid Code, whereas the Grid Code Management Committee shall be responsible for management of Grid Code for any changes, modifications in the Grid Code. The Grid Code Management Committee shall constitute following committees for implementation of the Grid Code:

(a) System Operation Code: State Operation and Co-ordination Committee (SOCC)

(b) Protection Code: State Protection Co-ordination Committee (SPCC)

(c) Transmission Metering Code: State Transmission Metering Committee (TMC)

II. The Grid Code Management Committee shall nominate the members of the functional committees. Chairman and Member Secretary of the functional committees shall be from the STU.

III. However, STU can formulate any other operational committee as it deems fit for the implementation of the Grid Code.

IV. Formation and roles of various committees to be formed under clause (I) above:

**(a) State Operation and Co-ordination Committee(SOCC)**

Operation and Co-ordination Committee shall coordinate the implementation of Load Despatch & System Operation Code to ensure that respective Generators and Distribution Licensees using Intra State transmission system discharge their obligations under the Grid Code.

OCC shall comprise of a senior representative from each Users of Intra State transmission system, as members, to be appointed by the Grid Code Management Committee, which shall meet once every three months and deliberate on all technical and operational aspects of Load Despatch and System Operation and shall give their recommendations to the Grid Code Management Committee. It shall conduct, inter alia, the following functions.

The rules to be followed by the committee in conducting their business shall be formulated by the Committee itself and shall be approved by Grid Code Management Committee. The functions are:

1. Review of existing interconnection and equipment for alteration, if necessary, so as to comply with the Connection Conditions provided for in the Code.
2. Deliberation on connectivity criterion for voltage un-balance as specified in Schedule-II of Transmission Performance Standards and taking remedial measure for cases failing to meet such criterion.
3. Review the load forecast and the methodology and assumptions made by each of the Distribution Licensees.
4. Review the load shedding through under frequencyrelays.
5. Transmission system planning coordination for the State as awhole.
6. Review and finalize the proposals identified on the basis of planning studies.

**(b) State Protection and Co-ordination Committee(SPCC)**

Protection Co-ordination Committee shall coordinate the implementation of Protection Code to ensure that respective Users using Intra State transmission system discharge their obligations under the Protection code.

Protection Co-ordination Committee shall consist of following members:

(i) Chairman who is an officer designated by STU.

(ii) Member Secretary who is also an officer from STU.

(iii) One representative from APGCL

(iv) One representative from each Distribution Licensees.

(v) One representative from SLDC.

(vi) One representative from NERLDC.

(vii) One representative from NERPC.

The rules to be followed by the Protection Co-ordination Committee in conducting their business shall be formulated by the committee itself and shall be approved by Grid Code Management Committee. The committee shall meet at least once in three months and conduct, inter alia, the following functions.

1. To keep Protection Code and its implementation under scrutiny & review.
2. To consider all requests for amendment to the Protection code which any user makes.
3. To publish recommendations for changes to the Protection code together with the reason for the change and any objection ifapplicable.

4. To issue guidance on the interpretation & implementation of the Protection code.
5. To deliberate and decide various protection settings testing procedure and periodicity.
6. To review and specify the optimum protection requirements for User's system connected to the Intra State transmission system.
7. To deliberate and prepare the Under Frequency Load Shedding Schemes and the mechanism to be adopted for the same for various sub-stations to ensure that the frequent tripping of same feeder is avoided.
8. Preparation and finalisation of technical requirement of various protections, Disturbance recorders, Event Loggers, along with under frequency load-shedding schemes the load-shedding through df/dt relay.
9. The DR (Disturbance Recorder) of the Numerical Relays/other Disturbance Recorder should be furnished by the STU to the SLDC within 24 hour of the occurrence of the disturbance.

**(c) State Transmission Metering Committee (STMC)**

Transmission Metering Committee shall be constituted as per the provisions of the Metering Code of these regulations.

The rules to be followed by the Metering Committee in conducting their business shall be formulated by the Metering Committee itself and shall be approved by Grid Code Management Committee. The Metering Committee shall meet at least once in three months.

**3.5 Non-Compliance & Relaxation**

3.5.1 Relaxation if any for any particular section or chapter of the Grid Code shall be with the express permission of the Commission for a specified time. Relaxation of any requirement of the Grid Code shall be exception and not the norm, and will be allowed only when it is impossible and not just difficult or inconvenient for the user to comply in the required time-scale. Failure to comply with the permitted time-frame of relaxation, by any User, shall carry a financial penalty, as may be decided by the Commission, while allowing relaxation.

**3.6 Monitoring of Compliance**

3.6.1 The monitoring agency for users shall be the SLDC in their control area. The monitoring agency shall track the progress of compliances of users, and exceptional reporting for non-compliance shall be submitted to the appropriate Commission.

3.6.2 The monitoring agency for SLDC shall be the Commission.

3.6.3 State Load Despatch Centre shall be responsible for monitoring the compliance of Users and State Transmission Licensees with the provisions, contained in Assam Electricity Grid Code and with the procedures developed under such provisions:

Provided that the State Transmission Utility and/ or State Load Despatch Centre shall not unduly discriminate against or unduly prefer any User or Transmission Licensee.

3.6.4 If any User fails to comply with any of the provision(s) of the Grid Code, it shall be required to inform STU/SLDC without any delay, the reason for its non-compliance and shall remove its non- compliance promptly and report the same to the Commission as stated earlier.

3.6.5 Wrong declaration of capacity, non-compliance of SLDC's instructions, non-compliance of SLDC's instructions for backing down without adequate reasons, non-furnishing data etc. shall constitute non-compliance of Grid Code and shall be subject to financial penalty as may be decided by the Commission.

3.6.6 In case of persistent non-compliance of the provisions of the Grid Code and/ or with the procedures developed under such provisions, such matter shall be reported to the Commission by SLDC. Consistent failure to comply with the Grid Code may lead to disconnection of the User's plant and/or facilities.

3.6.7 State Load Despatch Centre may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in the State.

3.6.8 Every Transmission Licensee and User connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre.

3.6.9 If any dispute arises with reference to the quality of electricity or safe, secure and integrated operation of the State grid or in relation to any direction given under the provisions of Assam Electricity Grid Code, it shall be referred to the Commission by SLDC for decision:

Provided that till the time the decision of the Commission is pending, the direction of the State Load Despatch Centre shall be complied with by the Transmission Licensee or User.

3.6.10 If any Transmission Licensee or any User fails to comply with the directions issued under Regulation 3.6.8 of the Grid Code, he shall be liable to penalty as per the Act.

3.6.11 The performance of all users, STU, SLDC, traders and QCAs with respect to compliance of these regulations shall be assessed periodically.

3.6.12 In order to ensure compliance, two methodologies shall be followed:

a) Self-Audit

b) Compliance Audit

3.6.13 Self –Audit:

a) All users, STU, SLDC, traders and QCAs, shall conduct annual self-audits to review compliance of these regulations and submit the reports by 31st July of every year.

b) The self-audit report shall inter alia contain the following information with respect to noncompliance:

(i) Sufficient information to understand how and why the non-compliance occurred;

(ii) Extent of damage caused by such non-compliance;

(iii) Steps and timeline planned to rectify the same;

(iv) Steps taken to mitigate any future recurrence;

c) The self-audit reports of all users, traders and QCAs shall be submitted to the SLDC. The self-audit reports of SLDC and STU shall be submitted to the Commission.

d) The deficiencies shall be rectified in a time bound manner within a reasonable time.

e) The State Power Committee (SPC), when constituted, shall also continuously monitor the instances of non-compliance of the provisions of these regulations and endeavor to sort out all operational issues and deliberate on the ways in which such cases of non-compliance shall be prevented in future. The Member Secretary may also report any unresolved issues to the Commission.

Until the formation of the SPC, SLDC shall be responsible for the monitoring and reporting as stated earlier in this regulation.

f) The Commission may initiate appropriate proceedings upon receipt of report under clauses 3.6.2 and 3.6.13(d).

g) In case of non-compliance of any provisions of these regulations by SLDC, SPC and any other person, the matter may be reported by any person to the Commission through filing of a petition.

3.6.14 Independent Third-Party Compliance Audit:

The Commission may order independent third-party compliance audit for any user, STU, SLDC as deemed necessary based on the facts brought to the knowledge of the Commission.

**3.7 State Power Committee (SPC):**

3.7.1 Governance Structure and constitution of the State Power Committee

a) Within three months from date of the notification of these regulations, the State Load Despatch Centre shall formulate Operating Procedures and Business Rules for constitution of State Power Committee, which shall be approved by the Commission.

b) The State Power Committee shall:

i. Co-ordinate and facilitate the intra-state energy exchange for ensuring optimal utilisation of resources.

ii. Monitor the compliance of these regulations as stated in Clause 3.6.13. e), the AERC (Deviation Settlement Mechanism and Other Related Matters) Regulations, 2024, the AERC (Terms and Conditions for Open Access) Regulations, 2024, the AERC (Ancillary Services) Regulations, 2024 and their subsequent amendments and any other regulations/orders as specified by the Commission. The SPC will monitor the compliance by State Entities and submit annual compliance report in the prescribed format within thirty days from close of financial year to the Commission.

iii. Guide the SLDC for modification of Procedure(s) in order to address the implementation difficulties, if any.

iv. Provide necessary support and advice to the Commission for suitable modifications/issuance of Operating Procedures, Practice Directions, and amendment to provisions of the Regulations stated in Clause 3.7.1 (b) (ii), as may be necessary upon due regulatory process.

**3.8** Till such committees as stated in Clauses 3.4 and 3.7 are constituted, SLDC shall perform the functions of the respective committees, as listed in these Regulations.

# PART II
# PLANNING CODE

## CHAPTER 4
## RESOURCE ADEQUACY CODE AND SYSTEM PLANNING CODE

### 4 Resource Adequacy Code

### 4.1 Introduction

This chapter covers the integrated resource planning including demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment, required for secure grid operation. The planning of generation and transmission resources shall be to meet the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix with a focus on integration of environment friendly 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.

### 4.2 Integrated Resource Planning

The integrated resource planning shall include:
(a) Demand forecasting;
(b) Generation resource adequacy planning; and
(c) Transmission resource adequacy planning.

### 4.3 Demand Forecasting and Generation Resource Adequacy Planning

4.3.1 The provisions related to demand assessment and forecasting and Generation Resource Adequacy Planning shall be governed by the provisions of Assam Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024 and amendments thereof. However, following are also to be considered:

4.3.1.1 Demand Forecasting:

(i) Each distribution licensee 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, in different time horizons, namely long-term, medium term and short-term. 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.

(ii) STU, 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.

4.3.1.2 Generation Resource Adequacy Planning:

(i) After the demand estimation as per clause (2) of this Regulation, each distribution licensee

a) shall assess the existing generation resources and identify the additional generation resource requirement to meet the estimated demand in different time horizons, and
b) prepare generation resource procurement plan.

(ii) Assessment of the existing generation resources shall be done with due regard to their capacity contribution to meet the peak demand of the distribution licensee and the state.

(iii) 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

a) adequacy of generation resources and
b) planning reserve margin (PRM) taking into account loss of load probability and energy not served as specified by CEA.

(iv) In order to ensure optimum and least cost generation resource procurement planning, each distribution licensee shall give due consideration to the factors such as its share in the state, regional and national coincident peak; seasonal requirement and possibility of sharing generation capacity seasonally with other States. For this purpose, STU shall provide to NLDC every year, the details regarding demand forecasting, assessment of existing generation resources and such other details as may be required for carrying out a national level simulation for generation resource adequacy for States, as required.

(v) 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 Commission. 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 specified by the Commission.

**4.4 Transmission resource adequacy planning**

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:
(a) Import and export capability across ISTS and STU interface; and
(b) Adequate power transfer capability across the Intra-State Transmission System.

**4.5 System Planning**

4.5.1 This code specifies the procedure to be applied by STU in the planning and development of the State Transmission System and also specifies the method for data submissions by Users to STU for development of Intra-State Transmission System. The provisions of System Planning Code are intended to enable STU to produce a plan in consultation with Users, to provide an efficient, coordinated, secure and economical State Transmission System to satisfy requirement of future demand.

4.5.2 In accordance with Section 39(2)(b) of the Act, STU shall discharge all functions of planning and coordination relating to intra-State transmission system with Central Transmission Utility, State Governments, Generating Companies, Regional Power Committees, Central Electricity Authority (CEA), Licensees and any other person notified by the State Government in this behalf.

4.5.3 A requirement for reinforcement or extension of the State Transmission System may arise for a number of reasons, including but not limited to the following:

(i) Development on a User's system already connected to the State Transmission System.
(ii) The introduction of a new Connection point between the User's system and the State Transmission System.
(iii) Evacuation system for Generating Stations within or outside the State.
(iv) Reactive Compensation.
(v) A general increase in system capacity (due to addition of generation or system load) to remove operating constraints and maintain standards of security.
(vi) Transient or steady state stability considerations.
(vii) Cumulative effect of any of the above.

4.5.4 Accordingly, the reinforcement or extension of the State Transmission System may involve work at an entry or exit point (Connection point) of a User to the State Transmission System. Since development of all User's systems must be planned well in advance to permit consents and way leaves to be obtained and detailed engineering design/construction work to be completed, STU will require information from Users and vice versa. To this effect, the Planning Code imposes time scale, for exchange of necessary information between STU and Users, wherever appropriate, to the confidentiality of such information.

4.5.5 The Planning Code provides the following:

- Defines the procedure for the exchange of information between STU and User in respect of any proposed User development on the User's system, which may have an impact on the performance of the User.

- Details the information which STU shall make available to Users in order to facilitate the identification and evaluation of opportunities for use or connection to State Transmission System.
- Details the information required by STU from Users to enable STU to plan the development of its Transmission System to facilitate proposed User developments.
- Specifies planning and design standards, which will be applied by STU in planning and development of the power system.

### 4.6 Planning Policy

4.6.1 STU would develop a perspective transmission plan for next ten (10) years on annual rolling basis for Intra-State Transmission System. The perspective transmission plan would be updated every year to take care of the revisions in load projections and generation capacity additions. The perspective plan shall be submitted to the Commission for approval.

4.6.2 STU shall carry out annual planning process corresponding to a five (5) year forward term for identification of major State Transmission System, which shall fit into National Power Plan formulated by Central Government long-term plan developed by CEA and the five (5) year plan prepared by Central Transmission Utility.

4.6.3 STU shall follow the following steps in planning:

(i) Based on the provisions of Resource Planning Code, Distribution Licensees shall provide the details of the Demand forecasting, Generation resource adequacy planning data, methodology and assumptions on which the forecasts are based, to the Commission and STU. These forecasts would be annually reviewed and updated by the concerned entities.

(ii) STU shall prepare a transmission plan for the State Transmission System compatible with Regulation 4.6.3 (i) of the Grid Code including provision for VAR compensation needed in the State Transmission System.

(iii) The reactive power planning exercise shall be carried out by STU in consultation with NERLDC/NERPC/SLDC/Distribution Licensees for installation of reactive compensation equipment.

(iv) Special attention shall be accorded by STU towards planning of capacitors, reactors, Static Volt Ampere Reactive Compensator (SVC), Static Volt Ampere Reactive Generator (SVG) and Flexible Alternating Current Transmission Systems (FACTS) and any other equipment, which is typically used to regulate and control the voltage within the specified limits.

(v) STU's planning department shall use load flow, short circuit and transient stability study, relay coordination study and other techniques for transmission system planning.

(vi) STU's planning department shall simulate the contingency and system constraint conditions for the system for transmission system planning.

(vii) The planning criteria shall be as per CEA Manual on Transmission Planning Criteria (Appendix-F) and amendment thereof.

4.6.4 All the Users shall supply to STU, the desired planning data by 31st May every year to enable STU to formulate and finalise the plan by 30th September each year for the next five (5) years.

### 4.7 Planning Responsibility

4.7.1 The primary responsibility of demand forecasting within Distribution Licensees' area of supply rests with the Distribution Licensees. Distribution Licensees shall determine their peak demand and energy forecasts for each category for each of the succeeding five (5) years and submit the same annually by 31st May to STU along with details of the Demand forecasting, Generation resource adequacy planning, data, methodology and assumptions on which the forecasts are based along with their proposals for transmission system augmentation. The demand forecasts shall be updated annually or whenever major changes are made in the existing forecasts or planning. While indicating requirements of single consumers with large demands (1 MW or higher) the Distribution Licensee(s) shall satisfy itself as to the degree of certainty of the demand materializing.

4.7.2 State Sector Generating Stations (SSGS) shall provide their generation capacity to STU for evacuating power from their power stations for each of the succeeding five (5) years along with their proposals for transmission system augmentation and submit the same annually by 31st May to STU.

4.7.3 Distribution Licensees shall provide details of Long-Term Access and Medium-Term Open Access PPAs signed with ISGS/IPPs/REGS for the succeeding five years to STU annually by 31st May.

4.7.4 STU shall initiate the planning for strengthening the Intra State transmission system for evacuation of power from outside state stations.

4.7.5 State Operation and Co-ordination Committee consisting of members from each Distribution Licensee, STU and APGCL shall review and approve the load forecasts and the methodology followed by each of the Distribution Licensees.

4.7.6 The Intra State transmission system proposals identified on the basis of planning studies would be discussed, reviewed and finalized by the SOCC.

### 4.8 Planning Data

4.8.1 To enable STU to conduct System Studies and prepare perspective plans for electricity demand, generation and transmission, the Users shall furnish data to STU from time to time as detailed under Data Registration Code as under:

(a) Standard Planning Data (Generation) / Standard Planning Data (Distribution) (Appendix-A)

(b) Detailed Planning Data (Generation) / Detailed Planning Data (Distribution) (Appendix-B)

4.8.2 To enable Users to co-ordinate planning, design and operation of their plants and systems with the State Transmission System, they may seek certain salient data of Transmission System as applicable to them, which STU shall supply from time to time as detailed under Data Registration Code and categorized as:
(a) Standard Planning Data (Transmission) (Appendix-A)
(b) Detailed Planning Data (Transmission) (Appendix-B)

4.8.3 STU shall also furnish to all the Users, Annual Transmission Planning Report, Power Map and any other information as the Commission may prescribe.

**4.9 Implementation of Transmission Plan**

The actual programme for implementation of transmission plan will be determined by STU in consultation of other Transmission Licensees. The STU/ Transmission Licensees shall ensure the completion of these works in the required time frame.

# CHAPTER 5
# CONNECTION CODE

## 5 Connection Code

### 5.1 Introduction

5.1.1 Connection Code specifies the technical, design and operational criteria for connectivity, procedure and requirements for physical connection and integration of grid elements, which must be complied with by any User connected to the State Grid.

5.1.2 The connectivity to Intra-State Transmission System shall be granted by State Transmission Utility and the Intra-state Distribution System by the concerned Discom in accordance with the Grid Code, and other applicable AERC regulations.

5.1.3 STU and Users connected to or seeking connection to the State Grid shall comply with the following Act/Regulations and amendments issued from time to time:

i. The Electricity Act, 2003;
ii. Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006;
iii. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007;
iv. Central Electricity Authority (Grid Standards) Regulations, 2010;
v. Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020;
vi. Central Electricity Authority (Cyber Security in Power Sector) Guidelines, 2021;
vii. Assam Electricity Regulatory Commission (Terms & Conditions for Open Access), Regulations 2024;
viii. Assam Electricity Regulatory Commission (Ancillary Services), Regulations 2024;
ix. Assam Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters), Regulations 2024;
x. Assam Electricity Regulatory Commission (Multi Year Tariff), Regulations 2024;
xi. Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022;
xii. Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter State Transmission System) Regulations, 2022 until the Assam Electricity Regulatory Commission Regulations comes into effect;
xiii. Central Electricity Authority (Measures Relating to Safety & Electric Supply) Regulations, 2023;
xiv. Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023;

In addition to above, all relevant Laws/Regulations/Guidelines/Rules/Standards with amendments as specified from time to time shall be applicable for grant of connectivity.

5.1.4 This Code shall be applicable to generators (including CGPs/ REGS), Energy Storage Systems, Distribution Licensees, Captive Users, Open Access Customers, Intra-State Transmission Licensees, HV/EHV Consumers of Distribution Companies and all other

Users of Intra-State Transmission System. The HV/EHV consumers seeking to avail power from State Distribution Companies shall however route their application for connectivity through concerned Distribution Licensee.

5.1.5 This Code shall apply to the application made for grant of connectivity to Intra-State Transmission System and other connectivity related matters, received by STU. The STU shall be the Nodal Agency for grant of connectivity to Intra-State Transmission System and all other matters connected therewith.

**5.2 Objective**

The objective of this chapter is to ensure the following:

(i) All Users or prospective Users are treated equally.

(ii) Any new Connection shall not impose any adverse effects on existing Users, nor shall a new Connection suffer adversely due to existing Users.

(iii) By specifying minimum design and operational criteria, to assist Users in their requirement to comply with Licence obligations and hence, ensure that a system of acceptable quality is maintained.

(iv) The ownership and responsibility for all items of equipment is clearly specified in a schedule (Site Responsibility Schedule as Appendix-G of this Grid Code) for every site where a Connection is made.

**5.3 Procedure for Connection**

5.3.1 Users seeking to get connected to the InSTS for the first time through a new or modified power system element shall fulfill the requirements and follow the procedures specified under this Code prior to obtaining the permission of energization from the SLDC. Transmission licensees including deemed transmission licensees or other intra-state entities shall comply with the technical requirements specified under this Connection Code prior to being allowed by SLDC to energize a new or modified power system element. After grant of connectivity and prior to the declaration of commercial operation, the tests as specified under Chapter-6 of these regulations shall be performed.

5.3.2 The existing Users, already connected to the Intra-State Transmission System prior to issuance of this Code shall not be required to make fresh application for connectivity for the same capacity. However, in case of any extension or modification of capacity of generating plant (including captive power plant), enhancement of capacity/load by HV/EHV consumer of Distribution Licensee connected at voltage 33 kV and above and the HV/EHV consumer of Distribution Licensee desiring connectivity to higher voltage will be required to make fresh application for connectivity.

5.3.3 Any new Intra-State Transmission Licensee entering into business of Intra-State Transmission of Electricity under Section 63 of the Act shall not be required to make an application for connectivity. STU shall connect transmission system of such Intra-State Transmission Licensee with the existing Intra-State Transmission System as per agreed terms and conditions stipulated in the bidding documents or the Licence granted by the Commission and Transmission Service Agreement (TSA) signed by the parties.

5.3.4 SLDC, after due consultation of stakeholders, shall prepare a detailed procedure covering modalities for processing of application, first time energization and integration of new or modified power system element to intra-State transmission system 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. The procedure shall thoroughly cover all aspects of connectivity to the intra-state transmission system including the draft formats and agreements.

5.3.5 Post completion of all physical arrangements of connectivity and necessary site tests, the concerned user shall request the SLDC for first time energization in the specified format as per the procedure published by SLDC.

**5.4 Procedure for Connection Application**

(i) The Applicant/ User shall submit application (as per Appendix-I) containing all the information as required by STU. The information must contain the details of arrangements to be made by User for drawal or injection of energy into the grid.

(ii) The Applicant/User shall ensure to have completed project planning, designing and pre-construction activities (including all licences, authorizations, permission and clearances as required from time to time under the Law) before making an application for grant of connectivity and satisfy STU of its preparedness for undertaking the project by specifying tentative date(s) of start of construction and commissioning of project. An undertaking to this effect shall be submitted along with a concise description of each activity completed.

(iii) The Applicant/User seeking connectivity with Intra-State Transmission System at 132 kV and above voltage or the Applicant/ User seeking connectivity with Intra-State Transmission System at 33 kV voltage through independent/ dedicated feeder from EHV Sub-station (besides Captive Generating Plants seeking connectivity from Intra-State Transmission System)/ Captive Generating Plants seeking Parallel Operation with the grid shall have to pay non-refundable application fee of Rs. 1,00,000/- (Rs. One Lakh) to STU towards feasibility studies for the connection. Intra-State Transmission Licensee developing Intra-State transmission network through Tariff Based Competitive Bidding (TBCB) or Distribution Licensees or Deemed Distribution Licensees or HV/EHV consumers applying through Distribution Licensees shall be exempted from payment of the aforesaid Application Fee. For Open Access Consumers, the charges shall be as per AERC (T&C for Open Access) Regulations, 2024.

(iv) The application not found in conformity with the format appended with these procedures shall be considered incomplete and will be returned to Applicant in original, mentioning the reasons. However, the Applicant/ User shall be given a reasonable opportunity of making a representation to STU before such rejection.

(v) STU shall process and finalize the application within sixty (60) days from the date of receipt of application, by conducting load flow studies for examining technical feasibility and to finalize other details like establishing requirement of bay, availability of space for construction of bay, details of transmission lines, works required for system strengthening and then convey it to concerned Distribution Licensee, if required under intimation to the Applicant/ User.

(vi) STU shall make a formal offer within ninety (90) days of the receipt of the application. The offer shall stipulate and take into account any works required for the extension or reinforcement of the State Transmission System necessitated by the applicant's proposal and for obtaining any consent necessary for the purpose. If the specified time limit for making the offer against any application is not adequate, STU shall make a preliminary offer within the specified time indicating the extent of further time required for detailed analysis.

(vii) Any offer made by STU shall remain valid for a period of sixty (60) days, unless accepted before the expiry of such period, and shall be treated as lapsed thereafter.

(viii) In the event of offer becoming invalid or not accepted by the Applicant, STU shall not consider the application from the same Applicant/ User within twelve (12) months, unless the new application is substantially different from the original application.

(ix) The applicant shall furnish the detailed planning data as per Appendix B

(x) STU shall be entitled to reject any application for connection to/or use of State Transmission System on the following conditions, but not limited to:

(a) If such proposed connection is likely to cause breach of any provision(s) of its licence or any provision of AEGC/ IEGC/ criteria or any covenants, deeds or regulations by which STU is bound.

(b) If the applicant does not undertake to be bound, in so far as applicable, by the terms of this Grid Code.

(c) If the applicant fails to give confirmation and undertakings according to this Grid Code.

(d) If the details of arrangement of drawal of energy are not disclosed by the Applicant/ User in his application.

## 5.5 Connectivity Agreement

5.5.1 A Connectivity Agreement (or the offer for a Connectivity Agreement) shall include, but not be limited to the following terms and conditions:

(a) A condition requiring both parties to comply with the Grid Code.

(b) Details of connection and/or use of system charges.

(c) Details of any capital related payments arising from necessary reinforcement or extension or modification of the system.

(d) Diagram of electrical system to be connected.

(e) General philosophy, guidelines etc. on protection.

(f) A Site Responsibility Schedule (Appendix-G).

(g) Details of arrangement of drawal of grid energy by User.

5.5.2 The Connectivity Agreement shall be executed between the following parties:

(i) In case of Generating Company/ Captive Generator or any Open Access customer seeking connectivity from STU sub-station at voltage level of 132 kV and above, the Agreement will be executed between Applicant and STU.

(ii) In case of Generating Company/ Captive Generator or any Open Access customer seeking connectivity from STU sub-station at voltage level of 33 kV, the Agreement will be executed between Applicant, STU and concerned Distribution Licensee, as the case may be.

(iii) In case of HV/ EHV consumer of Distribution Licensee seeking connectivity from STU sub-station at voltage level of 33 kV and above, the Agreement will be executed between Applicant, STU and concerned Distribution Licensee, as the case may be.

(iv) Connectivity Agreement shall be signed within sixty (60) days (unless otherwise indicated by STU) from the date of connection offer or within such additional time as may be granted by STU, depending upon the request made by Applicant/ User, if any.

5.5.3 Single Line Diagrams

(i) Single Line Diagram (SLD) shall be furnished for each Connection Point by the connected User to STU/ SLDC/ respective Intra-State Transmission Licensee. These diagrams shall include all HV connected equipment, location of ABT meters and connections to all external circuits and incorporate numbering, nomenclature and labelling, etc. The diagram is intended to provide an accurate record of the layout and circuit connections, rating, numbering and nomenclature of HV apparatus and related plant.

(ii) Whenever any equipment has been proposed to be changed, then User/ or agency responsible for O&M shall intimate the necessary changes to respective Intra-State Transmission Licensee and to all concerned.

(iii) When the changes are implemented, changed Single Line Diagram (SLD) shall be circulated by User/ or agency responsible for O&M to STU/ SLDC/ respective Intra-State Transmission Licensee.

5.5.4 Site Common Drawings

(i) Site Common Drawing will be prepared for each Connection Point and will include site layout, electrical layout, details of protection and common services drawings. Necessary details shall be provided by Users to STU.

(ii) The detailed drawings for the portion of User and respective Intra-State Transmission Licensee at each Connection Point shall be prepared individually and exchanged between User and respective Intra-State Transmission Licensee.

(iii) If any change in the drawing is found necessary, either by User or respective Intra-State Transmission Licensee, the details will be exchanged between User and respective Intra-State Transmission Licensee, as soon as possible.

5.5.5 Site Responsibility Schedule

For every Connection to the Intra State transmission system for which Connectivity Agreement is required, STU shall prepare a schedule of equipment with information supplied by the respective Users. This schedule, called a Site Responsibility Schedule, shall indicate the following for each item of equipment installed at the Connection site.

i. The ownership of equipment.
ii. The responsibility for control of equipment.
iii. The responsibility for maintenance of equipment.
iv. The responsibility for operation of equipment.
v. The manager of the site.
vi. The responsibility for all matters relating to safety of persons at site.

**5.6 System Performance**

5.6.1 All equipment connected to the State Transmission System shall be of such design and construction to enable Intra-State Transmission Licensee to meet the requirement of Standards of Performance. Distribution Licensees shall ensure that their loads do not cause violation of these standards.

5.6.2 Any User seeking to establish new or modified arrangement(s) for Grid connection and/or use of transmission system of STU shall submit the application in the form, as may be prescribed by STU.

5.6.3 For every new/ modified Connection sought, STU shall specify the Connection Point, technical requirements and the voltage to be used, along with the metering and protection requirements as specified in the Metering and Protection Codes of this Grid Code.

5.6.4 STU and SLDC shall jointly carry out a 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, STU and SLDC shall identify measures for facilitating the integration of the element, subject to grid security.

5.6.5 SSGS, IPPs shall make available to STU/ SLDC, the up-to-date capability curves for all Generating Units, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to/ Import from Intra-State Transmission System.

5.6.6 The frequency shall always remain within the band as specified in IEGC/ AEGC.

5.6.7 The User shall however, be subject to the grid discipline of SLDC/NERLDC as per guidelines mutually agreed with NERPC/NERLDC, as applicable.

5.6.8 The variation of voltage at the inter-connection point may not be more than the limit specified in Regulation 9.6 of the Grid Code. Distribution Licensees and Open Access Users shall ensure that their loads do not affect Intra-State Transmission System in terms of causing any:

i) Imbalance in the phase angle and magnitude of voltage at the inter-connection point beyond the limits specified by Transmission Performance Standards.

ii) Harmonics in the system voltage at the inter-connection point beyond the limits specified in Transmission Performance Standards.

STU may direct Distribution Licensees to take appropriate measures to remedy the situation.

5.6.9 In the event of Grid disturbances/ Grid contingencies in the National grid, Transmission Licensees of the State shall not be liable to maintain the system parameters within the normal range of voltage and frequency.

5.6.10 Insulation coordination of the User's equipment shall conform to Indian Standards issued by Bureau of Indian Standards (BIS). If BIS Standards are not available for a particular equipment or material, the standards defined by STU from time to time shall be followed.

5.6.11 Protection schemes and metering schemes shall be as detailed in the Protection and Metering Codes of this Grid Code.

5.6.12 Detailed Performance Standards and its compliance requirements have been stated separately in the document namely Assam Electricity Regulatory Commission (Transmission Performance Standards), Regulations, 2004 and amendments thereof drafted under the provisions of section 57 (1) read with section 86 (1)(i) of the Act.

### 5.7 Connection Point

5.7.1 State Sector Generating Station (SSGS)

i. Voltage at the point of connection may be 400/220/132 kV or as agreed with STU. Unless specifically agreed with STU, the Connection point shall be the outgoing feeder gantry of Power Station Switchyard.

ii. All the terminals, communication and protection equipment owned by SSGS within the perimeter of the Generator's site shall be maintained by the SSGS.

iii. The provisions for the metering system shall be as per the Metering Code. The other User's equipment shall be maintained by respective Users. From the outgoing feeders' gantry onwards, all electrical equipment shall be maintained by respective Transmission Licensee.

5.7.2 Distribution Licensee

**i.** Voltage at the point of connection may be LV side of power transformer, i.e., 33 kV or 11 kV or as agreed with STU. For EHV consumer directly connected to transmission system, voltage may be 220 kV or 132 kV.

ii. The Connection point shall be the outgoing feeder gantry/ cable termination on transmission tower/ pole at respective STU sub-station. STU shall maintain all the terminals. Communication and protection for the metering system as per the Metering Code.

iii. From the outgoing feeder gantry/ transmission line cable terminal structure onwards, all electrical equipment shall be maintained by respective Distribution Licensee.

5.7.3 IPPs, CPPs, EHV Consumers and Open Access Customers

i. Voltage at the point of connection may be 220/132kV or as agreed with STU.

ii. When sub-stations are owned by IPPs, CPPs, EHV Consumers, the Connection point shall be the outgoing feeder gantry on their premises.

iii. The connection point for Open Access Customers shall be the outgoing feeder gantry on the STU's Premises.

Provided, the Open Access Customers shall comply with the AERC (T&C for Open Access) Regulations, 2024, as amended from time to time.

5.7.4 No LILO (Loop in Loop out) connection shall be allowed to any agency other than transmission licensee.

**5.8 Equipment of Users/ State Transmission System at Connection Points**

5.8.1 Sub-station Equipment:

i) All EHV sub-station equipment shall comply with Bureau of Indian Standards (BIS)/ International Electro Technical Commission (IEC) Standards/ prevailing Code of practice.

ii) All equipment shall be designed, manufactured and tested and certified in accordance with the quality assurance requirements as per IEC/BIS standards.

iii) Each connection between User and STS shall be controlled by a circuit breaker capable of interrupting at the connection point, the short circuit current as advised by STU in the specific Connection Agreement.

5.8.2 The fault clearance time of the equipment directly connected to the Intra-State Transmission System shall be as per the CEA Technical Standards for Construction Regulations and amendments thereof.

5.8.3 Back-up protection shall be provided for required isolation/ protection in the event of failure of the primary protection system provided to meet the fault clearance time requirements as defined in Protection Code of the Grid Code.

5.8.4 If a Generating Unit is connected to Intra-State Transmission System directly, it shall withstand, until clearing of the fault by back-up protection on Intra-State Transmission System.

5.8.5 All users connected to Intra-State Transmission System shall provide protection system as specified in the Protection Code and this shall be made the part of the Connection Agreement.

5.8.6 The addition of reactive compensation to be provided by the User shall be indicated by STU in the Connection Agreement for implementation, wherever applicable.

**5.9 Generating Units and Power Stations**

5.9.1 A Generating Unit shall be capable of continuously supplying its normal rated active/ reactive output within the system frequency and voltage variation range indicated in Chapter 9 of the Grid Code, subject to the design limitations specified by the manufacturer.

5.9.2 A generating unit shall be provided with the protection as specified in the Protection Code, which condition shall be made a part of the Connection Agreement.

**5.10 Data and Communication Facilities**

5.10.1 Reliable and efficient speech and data communication systems shall be provided in accordance with CEA Technical Standards for Communication and CERC Communication System Regulations and amendments thereof by all the users to facilitate necessary communication and data exchange, and supervision/control of the grid by the SLDC, under normal and abnormal conditions.

5.10.2 All Users and Intra-State Transmission Licensees shall provide parameter such as flow, voltage and status of switches/ transformer taps, etc., in line with interface requirements and other guideline made available by SLDC.

5.10.3 All Users shall provide the required facilities at their respective ends and SLDC and this condition shall be indicated in the Connectivity Agreement.

5.10.4 The associated communication system to facilitate data flow up to appropriate data collection point/ Wide Band node on STU system including inter-operability requirements shall also be established by the concerned user as specified by STU in the Connectivity Agreement.

5.10.5 The communication system along with data links provided for speech and real time data communication shall be monitored in real time by all users, STU and SLDC to ensure high reliability of the communication links.

5.10.6 Unless otherwise agreed in Connection Agreement, the equipment for data transmission and communication shall be operational and maintained by the user in whose premises they are installed, irrespective of ownership.

**5.11 System Recording Instruments**

Recording instruments such as Data Acquisition System/ Disturbance Recorder/ Event Logger/ Fault Locator/ Wide Area Management System/ Phasor Measurement Unit (PMU) (including time synchronization equipment) shall be provided in the Intra-State Transmission System for recording of dynamic performance of the system. All Users and STU shall provide all the requisite recording instruments and shall always keep them in working condition.

**5.12 Procedure for Site Access, Site operational activities and Maintenance Standards**

The Connection Agreement will also indicate any procedure necessary for Site access, Site operational activities and maintenance standard for Intra-State Transmission Licensees equipment at User premises and vice versa.

**5.13 Schedule of assets of State Transmission Grid**

STU shall submit maintain a schedule of transmission assets, which constitute the State Grid, i.e., State Transmission System, updated annually, indicating ownership on which SLDC has operational control and responsibility and to be made available to the Commission whenever required

**5.14 Connectivity Standards applicable to Wind generation and Solar Generating Station using Inverters**

The connectivity standards specifying the technical equipment for wind generators and solar generating stations using inverters to be synchronized with the grid at 33 kV or above and comply with the connectivity conditions shall be as specified in CEA Technical Standards for Connectivity Regulations as amended.

**5.15 Commissioning of Connectivity**

5.15.1 The commissioning of all the new projects shall be governed as per Chapter 6 of the Grid Code.

5.15.2 The applicant and all Intra-State Transmission Licensees shall comply with the provisions made in the Connection Agreement, CEA Technical Standards for Communication Regulations and amendments thereof and other relevant Regulations of CEA, Commission, CERC, AEGC and IEGC as amended from time to time.

5.15.3 Special focus shall be made on technical requirements for connectivity to the grid, i.e., voice and data communication facilities, system recording instruments, protection, responsibilities for safety, cyber security, reactive power compensation, integration of data with SLDC and STU, SCADA and other provisions.

5.15.4 Installation of meters, its testing, calibration and reading and all matters incidental thereto shall be undertaken in conformity with CEA Metering Regulations and amendments thereof, Transmission Metering Code of this Grid Code and any other additional requirement as may be considered necessary by STU.

5.15.5 The applicant shall intimate timeline for commissioning of works at its end and of dedicated transmission line up to the point of connectivity at least three months in advance.

5.15.6 In case of Generating Stations, date of synchronization of Generating Station and Transmission Line shall be intimated at least one month in advance so that required clearances, charging permission, issue of unique charging code could be issued by SLDC in consultation with STU and respective Intra-State Transmission Licensee.

# CHAPTER 6
# COMMISSIONING AND COMMERCIAL OPERATION CODE

## 6 Commissioning and Commercial Operation Code

### 6.1 Introduction

This chapter covers aspects related to drawal of start-up power from and injection of infirm power into the grid, trial run operation, documents and tests required to be furnished before declaration of COD, and requirements for declaration of COD.

### 6.2 Drawal of Start Up Power and Injection of Infirm Power

6.2.1 A unit of a generating station including unit of a captive generating plant that has been granted connectivity to the intra-State Transmission System shall be allowed to inter-change power with the grid during the commissioning period, including testing and full load testing before the COD, after obtaining prior permission of the SLDC:

Provided that the SLDC while granting such permission shall keep grid security in view.

6.2.2 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 for generating stations other than REGS and ESS (except Hydro PSP ESS).

(c) Injection of infirm power shall not exceed 45 (forty-five) days from the date of first-time energization and integration (FTC) approval for REGS and ESS (except Hydro PSP ESS].

6.2.3 Notwithstanding the provisions of the above Regulation 6.2.2, the Commission may 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 the completion of the stipulated period.

Provided that for REGS and ESS (except Hydro PSP ESS), extension of period for injection of infirm power beyond the stipulated period may be allowed (a) for a period up to three months by SDLC on an application(s) made by such generating station or ESS(except Hydro PSP ESS) to SLDC along with detailed reasons, at least 10 days in advance of the completion of the stipulated period, (b) for a period beyond three months, by the Commission on an application(s) made by such generating station or ESS(except Hydro PSP ESS) along with detailed reasons, at least 15 days in advance of the completion of the stipulated period.

6.2.4 Drawal of start-up power shall be subject to payment of transmission charges as per the Assam Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2024 and amendments thereof.

6.2.5 The charges for deviation for drawal of start-up power or for injection of infirm power shall be as per Assam Electricity Regulatory Commission (Deviation

Settlement Mechanism and Related Matters] Regulations, 2024 and amendments thereof.

6.2.6 Start-up power shall not be used by the generating station for construction activities.

6.2.7 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 SLDC shall seek such information on each occasion of the interchange of power before COD. For this, the generating station shall furnish to the SLDC relevant details, such as those relating to the specific commissioning activity, testing, and full load testing, its duration and the intended period of interchange. The generating station shall submit a tentative plan for the quantum and time of injection of infirm power on day ahead basis to the SLDC.

6.2.8 In the case of multiple generating units of the same generating station or multiple generating stations owned by different entities connected at a common interface point, SLDC 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.

6.2.9 SLDC shall stop the drawal 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) In the case of default in payment of monthly transmission charges, charges under Assam Electricity Regulatory Commission (Multi Year Tariff) Regulations, 2024 and deviation charges under Assam Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 and its subsequent amendments.

**6.3 Data to be furnished prior to notice of Trial Run**

6.3.1 The following details, as applicable, shall be furnished by each entity generating station to the SLDC, STU and the beneficiaries of the generating station, wherever identified, prior to notice of trial run:

| **Description** | **Units** |
|---|---|
| Installed Capacity of generating station | MW |
| Installed Capacity of generating station | MVA |
| MCR | MW |
| Number x unit size | No x MW |
| Time required for cold start | Minute |
| Time required for warm start | minute |
| Time required for hot start | Minute |
| Time required for combined cycle operation under cold conditions | Minute |
| Time required for combined cycle operation under warm conditions | Minute |

| Description | Units |
|---|---|
| Ramping up capability | % per minute |
| Ramping down capability | % per minute |
| Minimum turndown level | % of MCR |
| Minimum turndown level | MW (ex-bus) |
| Inverter Loading Ratio (DC/AC capacity) | |
| Name of QCA (where applicable) | |
| Full reservoir level (FRL) | Metre |
| Design Head | Metre |
| Minimum draw down level (MDDL) | Metre |
| Water released at Design Head | $M^3$/ MW |
| Unit-wise forbidden zones | MW |

**6.4 Notice of Trial Run**

6.4.1 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 SLDC, STU and the beneficiaries of the generating stations, including intermediary procurers, wherever identified:

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.

6.4.2 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 SLDC, STU, Distribution Licensees of the State and the owner of the inter-connecting system.

6.4.3 The SLDC shall allow commencement of the trial run from the requested date or in the case of any system constraints, not later than seven (7) days from the proposed date of the trial run. The trial run shall commence from the time and date as decided and informed by the SLDC.

6.4.4 A generating station shall be required to undergo a trial run in accordance with the below mentioned Regulation 6.5 after completion of Renovation and Modernization for extension of the useful life of the project as per the Tariff Regulations.

**6.5 Trial Run of Generating Unit**

6.5.1 Trial Run of the Thermal Generating Unit shall be carried out in accordance with the following provisions:

(a) A thermal generating unit shall be in continuous operation at MCR for seventy-two (72) hours on designated fuel:

Provided that:

(i) short interruption or load reduction shall be permissible with the 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 the trial run shall not be less than MCR, excluding the 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.

(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 a repeat trial run. If the Generating Company decides to de-rate the unit capacity, the de-rated capacity in such cases shall not be more than 95% of the demonstrated capacity, to cater for primary response.

6.5.2 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 below mentioned Regulation 6.5.2(b) and such de-rating shall be effective from 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 go for a repeat trial run. If the Generating Company decides to de-rate the unit capacity, the de-rated capacity in such cases shall not be more than 90% of the demonstrated capacity to cater for primary response.

6.5.3 Trial Run of Solar/ Wind/ ESS/ PSP/ Hybrid Generating Station:

(a) Trial run of the solar inverter unit(s) connected at State Transmission system shall be performed for a minimum capacity of 5 MW:

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

Successful trial run of a solar inverter unit(s) covered under the above Regulation

6.5.3(a) shall mean the flow of power and communication signal for not less than four 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 below mentioned Regulation 6.5.3(f).

(b) Trial run of a wind turbine(s) connected at State Transmission system shall be performed for a minimum capacity of 5 MW:

Provided that in the case of a project having a capacity of more than 5 MW, the trial run for wind turbine(s) above the capacity of 5 MW shall be performed in batch sizes of not less than 5 MW:

Successful trial run of a wind turbine(s) covered under the above Regulation 6.5.3(b) shall mean the flow of power and communication signal for a period of not less than four (4) hours on a cumulative basis in a single day 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 below mentioned Regulation 6.5.3(f).

(c) Successful trial run of a standalone Energy Storage System (ESS) connected at State Transmission system shall mean one (1) complete cycle of charging and discharging of energy as per the design capabilities with the requisite metering, telemetry and protection system being in service.

(d) Successful trial run of a Pumped Storage Plant (PSP) connected at State Transmission system shall mean one (1) complete cycle of turbo-generator and pumping motor mode as per the design capabilities up to the rated water drawing levels with the requisite metering, telemetry and protection system being in service.

Provided that if it is not possible to demonstrate the design capabilities up to the rated water drawing levels due to insufficient reservoir levels, the COD may be declared after demonstrating the capabilities at available water drawing levels, subject to the condition that design capabilities up to the rated water drawing levels shall be demonstrated immediately when sufficient reservoir level is available after COD.

Provided further that if such a generating station is not able to demonstrate the design capabilities when sufficient water is available, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity. If the generating company decides to de-rate the unit capacity in terms of Regulation 6.5.2(b) of these Regulations, such de-rating shall be effective from the COD

(e) Successful trial run of a hybrid system connected at State Transmission system shall mean successful trial run of each individual source of the hybrid system in accordance with the applicable provisions of this Grid Code.

(f) Where, on the basis of the trial run, solar/ wind/ ESS/ PSP/ hybrid generating station connected at State Transmission system 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 5 MW and above, as the case may be.

(g) Notwithstanding the provisions contained in the Grid Code, 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.

**6.6 Trial Run of Intra-State Transmission System**

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 inter-connection 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 STU and SLDC, a transmission element can be energized at lower nominal system voltage level:

Provided further that the STU and SLDC may allow anti-theft charging where the transmission line is not carrying any power.

## 6.7 Documents and Tests Prior to Declaration of Commercial Operation

6.7.1 Notwithstanding the requirements in other standards, codes and contracts, for ensuring grid security, the tests as specified in the following Regulations shall be scheduled and carried out in coordination with SLDC and STU 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 SLDC and STU before a certificate of successful trial run is issued to such a Generating Company or the Transmission Licensee, as the case may be.

6.7.2 All thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW shall submit documents confirming the enablement of automatic operation of the 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 CEA Technical Standards for Construction Regulations and CEA Technical Standards for Connectivity Regulations and amendments thereof.

6.7.3 Documents and Tests Required for Thermal (coal/lignite) Generating Stations:

(a) The Generating Company shall submit the following documents from the Original Equipment Manufacturer (OEM), 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.

(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 Regulations for a sustained period of four (4) hours.

(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 Regulations 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).

(v) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 55%, 60%, 75% and 100% load.

(vi) Reactive power capability as per the generator capability curve as provided by OEM considering over-excitation and under-excitation limiter settings and prevailing grid condition.

6.7.4 Documents and Tests Required for Hydro Generating Stations including Pumped Storage Hydro Generating Station:

(a) The Generating Company shall submit documents from the OEM 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, wherever feasible.

(iv) Operation in synchronous condenser mode, wherever designed.

6.7.5 Documents and Test Required for Gas Turbine based Generating Stations:

(a) The Generating Company shall submit documents from the OEM 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, wherever feasible.

(iv) Operation in synchronous condenser mode, wherever designed.

6.7.6 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 Regulations, in accordance with Regulation 6.9.4 of the Grid Code.

(b) The Type test report for Fault Ride through Test (LVRT and HVRT) for units commissioned after the specified date as per CEA Technical Standards for Connectivity Regulations and amendments thereof, mandating LVRT and HVRT capability shall be submitted.

(c) The following tests shall be performed at the point of inter-connection:

(i) Frequency response of machines as per the CEA Technical Standards for Connectivity Regulations.

(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.

6.7.7 Documents and Tests Required for Energy Storage Systems:

(a) The ESS shall submit a certificate confirming compliance with the CEA Technical Standards for Connectivity Regulations, in accordance with Regulation 6.9.4 of the Grid Code.

(b) The following tests shall be performed at the point of inter-connection:

(i) Power output capability in MW and energy output capacity in MWh.

(ii) Frequency response of ESS.

(iii) Ramping capability as per design.

6.7.8 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).

6.7.9 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.

**6.8 Certificate of Successful Trial Run**

6.8.1 In case any objection is raised by a beneficiary in writing to the SLDC with a copy to all concerned regarding the trial run within two (2) days of completion of such trial run, the SLDC 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 if there is a need for a repeat trial run.

6.8.2 After completion of a successful trial run and receipt of documents and test reports as per Regulation 6.7 of the Grid Code, the SLDC 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) and the STU and RPC, within three days.

**6.9 Declaration by Generating Company and Transmission Licensee**

6.9.1 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 Regulations, CEA Technical Standards for Connectivity Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations, CEA Flexible Operation Regulations and this Grid Code, as applicable.

(ii) The main plant equipment and auxiliary systems including the balance of the plant such as the fuel oil system, coal handling plant, DM plant, pre-treatment plant, fire-fighting system, ash disposal system and any other site-specific system have been commissioned and are capable of full load operation of the units of the generating station on a sustained basis.

(iii) Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of the unit have been put into service.

(b) The certificates required under the above Regulation 6.9.1(a) 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 SLDC before the declaration of COD.

6.9.2 Hydro Generating Station

(a) The Generating Company shall certify that:

(i) The generating station or unit thereof meets the requirement and relevant provisions of the CEA Technical Standards for Construction Regulations, CEA Technical Standards for Connectivity Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations and this Grid Code, as applicable.

(ii) The main plant equipment and auxiliary systems including the drainage de-watering system, primary and secondary cooling system, LP and HP air compressor and firefighting system have been commissioned and are capable of full load operation of units on a sustained basis.

(iii) Permanent electric supply systems including emergency supplies and all necessary Instrumentations Control and Protection Systems and auto loops for full load operation of the unit are put into service.

(b) The certificates required under the above Regulation 6.9.2(a) 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 SLDC before the declaration of COD.

6.9.3 Transmission system

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 SLDC and to the STU before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction Regulations, CEA Technical Standards for Connectivity Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations and this Grid Code and are capable of operation to their full capacity.

6.9.4 Wind, Solar, Storage and Hybrid Generating Stations

The generating station based on wind and solar resources, ESS, and hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the SLDC and to the STU 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 Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations and this Grid Code.

**6.10 Declaration of Commercial (DOCO) and Commercial Operation Date (COD)**

6.10.1 A generating station or unit thereof or a transmission system or an element thereof or ESS may declare commercial operation as follows and inform SLDC, STU and its beneficiaries:

(a) Thermal Generating Station or a unit thereof

(i) The commercial operation date in the case of a unit of the thermal generation station shall be the date declared by the Generating Company after a successful trial run at MCR or de-rated capacity as per Regulation 6.5.1(b) of the Grid Code, as the case may be, and submission of a declaration as per Regulation 6.9.1 of the Grid Code.

(ii) In the 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.

(b) Hydro Generating Station

(i) The commercial operation date in the case of a unit of the hydro generating station including a pumped storage hydro generating station shall be the date declared by the generating station after a successful trial run at MCR or de-rated capacity as per Regulation 6.5.2(b) of the Grid Code, as the case may be, and submission of a declaration as per Regulation 6.9.2 of the Grid Code.

(ii) In the 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.

**(c) Transmission System**

(i) The commercial operation date in the case of an Intra-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 signals from the sending end to the receiving end as per Regulation 6.6 of the Grid Code and submission of a declaration as per Regulation 6.9.3 of the Grid Code:

Provided that the commercial operation date of a transmission element shall be declared only after a successful trial run of the last element of the said transmission system:

Provided further that where only some of the transmission elements of the transmission system have achieved a successful trial run and commercial operation is sought for such elements, the commercial operation date of such transmission elements of the transmission system may be declared by the Transmission Licensee as per this Grid Code:

Provided also that where only some of the transmission element(s) of the transmission system have achieved a successful trial run and if the operation of such transmission elements is certified by the STU and concerned Regional Power Committee(s) for improving the performance, safety and security of the grid, the commercial operation date of such transmission element(s) of the transmission system may be declared by the Transmission Licensee as per this Grid Code:

Provided also that in case a transmission system or an element thereof executed under regulated tariff mechanism is prevented from regular service on or after the scheduled COD for reasons not attributable to the Transmission Licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other Transmission Licensee or downstream distribution system of Distribution Licensee, the Transmission Licensee shall approach the Commission through an appropriate petition along with a certificate from the STU to the effect that the transmission system is complete as per the applicable CEA Standards, for approval of the commercial operation date of such transmission system or an element thereof:

Provided also that in the case of Intra-State Transmission System executed through Tariff Based Competitive Bidding, the Transmission Licensee may declare deemed COD of the Intra-State Transmission System in accordance with the provisions of the Transmission Service Agreement after obtaining (a) a certificate from the STU 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 SLDC, where no load charging is possible.

(ii) The COD of a transmission element of the transmission system under Tariff Based Competitive Bidding (TBCB) shall be declared only after the declaration of the COD of all the pre-required transmission elements as per the Transmission Services Agreement (TSA):

Provided that in case any transmission element is required in the interest of the power system as certified by the STU, the COD of the said transmission element may be declared prior to the declaration of the COD of its pre-required transmission elements.

(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 hours of which a communication system or element thereof shall be put into service after completion of the site acceptance test including transfer of voice and data to the respective control centres as certified by State Load Despatch Centre.

(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 5 MW and above or such other limit as specified in Regulation 6.5.3 of the Grid Code, shall mean the date declared by the generating station after undergoing a successful trial run as per Regulation 6.5.3 of the Grid Code, submission of declaration as per Regulation 6.9.4 of the Grid Code, and subject to fulfilment of other conditions, if any, as per PPA.

(ii) In the case of a generating station as a whole, the commercial operation date of the last unit of the generating station shall be considered as the COD of the generating station.

6.10.2 On declaration of commercial operation date, scheduling of the generating station or unit thereof, shall start from 0000 hours of D+2 (where D is the date when a generating station intimates the commercial operation of the generating station or unit thereof) or the commercial operation date declared by the generating station or unit thereof, whichever is later.

# PART III
# LOAD DESPATCH & SYSTEM OPERATION CODE

## CHAPTER 7
## OPERATIONAL PLANNING CODE

### 7 Operational Planning Code

### 7.1 Operating Philosophy

7.1.1 All Intra-State Users 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.

7.1.2 Operation of the State grid shall be monitored by SLDC.

7.1.3 Detailed Operating Procedures for State grid shall be developed, maintained and updated by the SLDC, consistent with the Detailed Operating Procedures of respective RLDC.

7.1.4 SLDC shall have qualified operating personnel manning the control room round the clock.

7.1.5 Every generating station and transmission sub-station 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 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 sub-station, shall have a coordination centre functioning round the clock, manned by qualified personnel for operational coordination with SLDC and equipped to carry out the operations as directed by SLDC.

7.1.6 Qualified Coordinating Agency (QCA) shall have coordination centres functioning round the clock, manned by qualified personnel for operational coordination with SLDC and generating stations. ESS and Bulk Consumers, which are State entities, shall have coordination centres functioning round the clock and manned by qualified personnel for operational coordination with SLDC.

### 7.2 System Security

7.2.1 All Users shall operate their respective power systems in an integrated manner at all times in coordination with SLDC.

7.2.2 All switching operations, whether manually or automatic, will be based on regulatory provisions of IEGC, AEGC, CEA Regulations or any other guidelines issued by appropriate Authority from time to time.

7.2.3 No element (s) of the State Grid shall be deliberately isolated from the Grid, except:

(a) Under an emergency as per the Detailed Operating Procedure of SLDC, as the case may be, where such isolation would prevent a total Grid collapse and/ or enable early restoration of power supply;

(b) When serious damage to a critical equipment is imminent and such isolation would prevent it;

(c) For safety of Human Life;

(d) When such isolation is specifically advised by SLDC; and

(e) On operation of under frequency/ islanding scheme as approved by NERPC/ SLDC.

Any such isolation shall be reported to SLDC within next fifteen (15) minutes.

7.2.4 SLDC, in consultation with all users, shall prepare a list of important elements in the State grid that are critical for State grid operation and shall make the said list available to all concerned Users.

7.2.5 Any element of the above category not cannot be taken out of service without prior approval of SLDC unless under emergency condition specified under clause 7.2.3..

7.2.6 In case of switching off or tripping of any of the important elements of the State Grid under emergency conditions or otherwise, it shall be intimated immediately by the Users with available details to SLDC and SLDC shall intimate to RLDCwherever applicable. The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within15 minutes. The SLDC and the Users shall ensure restoration of such elements within the estimated time of restoration, as intimated.

7.2.7 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 SLDC, in coordination with concerned RLDC and NLDC in accordance with the system restoration procedures of NLDC or RLDC or SLDC.

7.2.8 Maintenance of grid elements shall be carried out by respective User in accordance with the provisions of the CEA Grid Standards Regulations and amendments thereof. Outage of an element that is causing or likely to cause danger to the State grid or sub-optimal operation of the State grid shall be monitored by SLDC. SLDC shall report such outages to NERLDC, wherever applicable. SLDC shall also issue suitable instructions to restore such elements in a specified time period.

7.2.9 Except in an emergency, or when it becomes necessary to prevent imminent damage to critical equipment, no user shall suddenly reduce its generating unit output by more than 20 (twenty) MW without prior permission of the SLDC.

7.2.10 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 SLDC.

7.2.11 No Generator shall desynchronise / synchronise its Generating Units without prior permission from the SLDC.

7.2.12 All generating units shall have their Automatic Voltage Regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers (Power Plant Controller) and any other requirements in operation, as per CEA Technical Standards for Connectivity Regulations and amendments thereof. 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 SLDC of the reasons thereof and the likely duration of such operation and obtain its permission.

7.2.13 The tuning of AVR, PSS, Voltage Controllers (PPC) 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 SLDC, after analysis of a grid event or disturbance;
- in case of major network changes or fault level changes near the generating station as reported by SLDC; and
- in case of a major change in the excitation system of the generating station.

7.2.14 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 NERPC/SLDC. In case the tuning is not complied with as per the plan and procedure, the SLDC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the SLDC may approach the Commission under Section 33(4) of the Act.

7.2.15 SLDC shall prepare the islanding schemes for the State Grid in accordance with the CEA Grid Standards Regulations and amendments thereof 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 at least once a year or earlier, if required.

7.2.16 Mock drill of the islanding schemes prepared by SLDC shall be carried out annually by SLDC in coordination with respective RLDC and other Users involved in the islanding scheme. 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 SLDC.

7.2.17 All Distribution Licensees, STU and Users 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 NERPC from time to time. The default UFR settings shall be as specified in Table below or as amended in IEGC from time to time:

| Sr. No. | Stage of UFR Operation | Frequency (Hz) |
|---|---|---|
| 1. | Stage-1 | 49.40 |

| Sr. No. | Stage of UFR Operation | Frequency (Hz) |
|---|---|---|
| 2. | Stage-2 | 49.20 |
| 3. | Stage-3 | 49.00 |
| 4. | Stage-4 | 48.80 |
| **Note-1:** STU shall plan UFR settings and df/dt load shedding schemes depending on load generation balance in coordination with SLDC and approval of the NERPC. | | |
| **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. | | |

Provided that the quantum of load relief under each stage of UFR shall be as indicated by the NERPC to Assam.

Provided further that the particulars of feeders or group of feeders at STU sub-station, which shall be tripped under under-frequency load shedding scheme whether manually or automatic on rotational basis or otherwise, will be available at the sub-station for information of the consumer(s).

7.2.18 The following shall be factored in while designing and implementing the UFR and df/dt relay schemes:

(a) The under-frequency and df/dt load shedding relays are always functional.

(b) Demand disconnection shall not be set with any time delay in addition to the operating time of the relays and circuit breakers.

(c) There shall be a uniform spatial spread of feeders selected for UFR and df/dt disconnection.

(d) SLDC shall ensure that telemetered data of feeders (MW power flow in real time and circuit breaker status) on which UFR and df/dt relays are installed is available at its control centre. SLDC shall monitor the combined load in MW of these feeders at all times. SLDC shall share the above data with NERLDC/NERPC, wherever applicable and submit a monthly exception report to GCMC and NERPC wherever applicable. SLDC shall inform the GCMC and the SPCon a quarterly basis, durations during the quarter when the combined load in MW of these feeders was below the level considered while designing the UFR scheme by SLDC. SLDC shall take corrective measures within a reasonable period, failing which suitable action may be initiated by the SPC.

(e) SPC shall undertake a bi-monthly review of UFR and df/dt scheme and may also carry out random inspection of the under-frequency relays. SLDCshall publish such review along with an exception report, after concurrence from the SPC, on its website.

(f) SLDC shall report the actual operation of UFR and df/dt schemes and load relief to the NERLDC and NERPC and publish the monthly report on its website.

7.2.19 SLDC, STU or Users may identify the requirement of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system within operating limits and to protect against situations such as voltage collapse, cascade tripping and tripping of important corridors/flow-gates.

Any such SPS at the intra-state level shall be finalized by the SLDC in concurrence with the NERPC and NERLDC. SPS shall be installed and commissioned by the concerned Users. SPS shall always be kept in service. If any SPS at the intra-State level is to be taken out of service, the permission of the SLDC shall be required and the same shall be informed to NERLDC, wherever applicable.

7.2.20 SLDC and Users shall operate in a manner to ensure that the steady state grid voltage as per
CEA Grid Standards Regulations, and amendments thereof, remains within the following operating 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 and subsequent updations.*

7.2.21 SLDC shall take appropriate measures to control the voltage as per its operating procedures.

7.2.22 The concerned Users shall implement defence mechanisms as finalized by the NERPC/SLDC to prevent voltage collapse and cascade tripping.

7.2.23 All defence mechanisms shall always be in operation and any exception shall be immediately intimated by the concerned User to the SLDC along with the reasons and the likely duration of such exception. The concerned User shall also obtain permission from SLDC.

### 7.3 Operational Planning

7.3.1 Time Horizon

a) Operational planning shall be carried out in advance by SLDC within its control area with Monthly and Yearly time horizons in co-ordination with CTU, RPCs or STUs, as applicable.

b) Operational planning shall be carried out in advance by SLDC within its control area on Intra-day, Day Ahead, Weekly time horizons.

c) SLDC, in consultation with NERLDC, shall issue procedures and formats for data collection to carry out:

i. Operational planning analysis,
ii. Real-time monitoring,
iii. Real-time assessments.

7.3.2 Demand Estimation

a) 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 Chapter 4 of these regulations. Demand estimation by SLDC shall be for both active power and reactive power incidents 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) SLDC shall develop methodology for daily, weekly, monthly, yearly demand estimation in MW and MWh for operational analysis as well as resource adequacy purposes. 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 a historical database of demand.

c) The demand estimation by SLDC shall be done on day ahead basis with time block wise granularity for the daily operation and scheduling. In case SLDC observes a major change in demand in real time for the day, it shall immediately submit the revised demand estimate to the NERLDC for demand estimate correction.

d) SLDC shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVA on a monthly and quarterly basis for the nodes 132 kV and above for the preparation of scenarios for computation of TTC and ATC by the NERLDC and NLDC.

e) SLDC shall also estimate peak and off-peak demand (active as well as reactive power) on a 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 the net load incident taking into account embedded generation in the form of roof-top solar and other distributed generation.

f) Based on the demand estimate furnished by the SLDCs and other entities directly connected to ISTS, the regional demand estimate and the national demand estimates shall be prepared by NERLDC and NLDC respectively as per the IEGC.

g) Timeline for submission of demand estimate data by SLDC, as applicable, to the respective RLDC and RPC, in line with IEGC, is shown as follows:

TABLE : TIMELINE FOR DEMAND ESTIMATION (submission by SLDC)

| | |
|---|---|
| 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 |

h) All state entities i.e generators, APDCL, Bulk Consumers to provide the data as per the following timeline to allow SLDC to compile the data and provide to NERLDC:

TABLE : TIMELINE FOR DEMAND ESTIMATION (submission to SLDC)

| | |
|---|---|
| Daily demand estimation | 09:00 hours of previous day |
| Weekly demand estimation | 9:00 hrs of First working day of previous week |
| Monthly demand estimation | Fourth Day of Previous month |
| Yearly demand estimation | 15th September of the previous year |

i) SLDC shall compute forecasting error for intra-day, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in the future.

j) The computed forecasting errors shall be made available by SLDC on their website.

7.3.3 Generation Estimation

a) The modalities of generation estimation by entities shall be as per the Procedure referred to in clause 7.3.1 and 7.3.2 of these regulations and the Resource Adequacy Framework.

b) SLDC shall forecast generation from wind, solar, ESS and Renewable Energy hybrid generating sources that are intra-state entities with inputs received from the generators, for different time horizons as referred to in clause 7.3.1 of these regulations for the purpose of operational planning.

7.3.4 Adequacy of Resources

a) SLDC shall estimate and ensure the adequacy of resources, identify generation reserves, demand response capacity and generation flexibility requirements with due regard to the Resource Adequacy Framework as specified under Chapter 4 of these regulations.

b) SLDC 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, as per IEGC, 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;
v. Secondary and planned procurement through Tertiary reserve requirement;
vi. Planned procurement of power through other bilateral or collective transactions, if any.

**7.4 Operational Planning Study**

7.4.1 Based on the operational planning analysis data, operational planning study shall be carried out by SLDC for time horizons in line with IEGC, reproduced as follows:

TABLE : TIME HORIZON FOR OPERATIONAL PLANNING STUDY

| Time horizon of operational planning study | Means for carrying out study |
|---|---|
| Real time and Intra-day | For various operating conditions using online/offline SCADA/EMS system |
| Day-ahead | For various operating conditions using offline tools |
| Weekly | For various operating conditions using offline tools |

7.4.2 SLDC shall utilize the network estimation tool integrated in their EMS and SCADA systems for the real time operational planning study. All users shall make available at all times real time error free operational data for the successful execution of network analysis using EMS/SCADA. Failure to make available such data shall be immediately reported to the SLDC along with a firm timeline for restoration. The performance of online network estimation tools and telemetry issues at SLDC shall be reviewed in the monthly operational meeting of NERPC, as per the IEGC, for their early resolution.

7.4.3 SLDC shall perform day-ahead, weekly, monthly and yearly operational studies for the State for:

a) assessment and declaration of total transfer capability (TTC) and available transfer capability (ATC) for the import or export of electricity by the State. TTC and ATC shall be revised from time to time based on the commissioning of new elements and other grid conditions and shall be published on SLDC website with all the assumptions and limiting constraints;
b) planned outage assessment;
c) special scenario assessment;
d) system protection scheme assessment;
e) natural disaster assessment; and
f) any other study relevant in operational scenario.

7.4.4 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. The deviations, if any, shall be submitted for review in the monthly operational meeting of RPC.

7.4.5 SLDC shall maintain records of the completed operational planning study, including date of specific power flow study results, the operational plan and minutes of meetings on operational study.

7.4.6 SLDC shall have operating plans to address potential deviations from system operational limit identified as a result of the operational planning study. These operating plans shall be communicated to users in advance so that they can take corrective measures. In case any user is unable to adhere to such an operating plan, it shall inform the respective SLDC, RLDC and NLDC in advance with detailed reasons and explanations for the non-adherence. These detailed reasons and explanations shall be submitted for discussion in the monthly operation sub-committee of the region. The quarterly report of the same shall be submitted to the Commission.

7.4.7 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 and share the results of the studies with NERLDC.

APGCL/AEGCL/APDCL/other generators/bulk consumers/other transmission licensees shall provide SLDC the details of new elements to be commissioned in the next six months with the state grid in the formats prescribed by SLDC.

7.4.8 SLDC 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 STU, as applicable, and any significant variations observed shall be communicated to CEA, RPC and STU for immediate and long-term mitigation measures.

7.4.9 Defense mechanisms like system protection scheme, load-rejection scheme, generation run-back, islanding scheme or any other scheme for system security shall be proposed by the concerned user or SLDC or RLDC or NLDC and shall be deployed as finalized by the respective NERPC, as per the IEGC.

**7.5 Demand Control**

7.5.1 Primarily the need for demand control would arise on account of the following conditions:

- Variations in demand from the estimated or forecasted values, which cannot be absorbed by the grid;
- Unforeseen generation/ transmission outages resulting in reduced power availability; and
- Heavy reactive power demand causing low voltages.

7.5.2 SLDC shall match the consolidated demands of the DISCOMs with consolidated generation availability from SSGS, ISGS, IPP/CGP and other sources and exercise Demand Control to ensure that there is a balance between the energy availability and the DISCOMs demand plus losses plus the required reserve.

7.5.3 On exhaustion of all methods of demand management, SLDC may exercise load curtailment directly through tripping of circuit breaker using RTUs or through telephonic instructions.

**7.6 Demand Management**

(a) All Users/ Distribution Licensees shall restrict their drawal from the grid, within the net drawal schedule for ensuring grid security.

(b) Distribution Licensees shall ensure that requisite load shedding is carried out in its control area, so that there is no over drawal. Distribution Licensees shall also provide to SLDC, time-block wise details of such load shedding.

(c) SLDC, in coordination with STU and Distribution Licensee(s), shall develop Automatic Demand Management scheme with emergency controls at SLDC.
The Distribution Licensees, in consultation with SLDC, shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response (as per the AERC Demand Response Regulations, 2024) etc., to reduce over drawal in order to comply with Regulation 7.6 (a) and Regulation 7.6 (b) of the Grid Code.

(d) In order to maintain the frequency within the stipulated band and maintain the network security, the interruptible loads shall be arranged in four groups, viz., load for scheduled power cuts/ load shedding, load for unscheduled load shedding, load to be shed through under frequency relays/df/dt relays and load to be shed under any System Protection Scheme identified at RPC/ state level. These loads shall be grouped in such a manner, that there is no overlapping between different groups of loads. In case of certain contingencies and/or threat to system security, the NERLDC may direct SLDC to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon by Users/ Distribution Licensees.

(e) SLDC shall devise standard, instantaneous, message formats in order to give directions in case of contingencies and /or threat to the system security to reduce deviation from the schedule by the Users/ Distribution Licensees/ Injecting Utility at different overdrawal/ Under Drawal/ Over-Injection/Under Injection conditions depending upon the severity. SLDC shall also ensure immediate compliance of these directions and any violation of SLDC's directions shall be intimated to the Commission through monthly report.

(f) All Users /distribution licensee shall comply with direction of SLDC and carry out requisite load shedding or backing down of generation in case of congestion in transmission system to ensure safety and reliability of the system. The procedure for application of measures to relieve congestion in real time as well as provisions of withdrawal of congestion shall be in accordance with detailed procedure in accordance with Central Electricity Regulatory Commission (Measures to relieve congestion in real time operation) Regulations, 2009 and amendments thereof or any relevant guidelines/ Regulations issued by appropriate Authority/ Commission. In case of shortage of power availability with respect to demand, the DCC of the distribution licensees shall resort to shedding the load on economic principle.

(g) The measures taken by Users/ Distribution Licensee shall not be withdrawn as long as the frequency remains at outside the limits or congestion continues, unless specifically permitted by the SLDC.

## 7.7 Post-Despatch Analysis

7.7.1 Operational analysis

(a) SLDC shall analyse the following:

(i) Pattern of demand met, under drawals and over drawals, 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;

(ii) Generation mix in terms of source and station-wise generation;

(iii) Irregular pattern in any of the system parameters mentioned in Regulation 7.7.1. (a)(i) and Regulation 7.7.1(a)(ii) of the Grid Code and reasons thereof; and

(iv) Extreme weather events or any other event affecting grid security.

(b) Such analysis shall be disclosed by SLDC on its website.

(c) SLDC shall prepare a quarterly report that shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of actions taken, including by those responsible for causing disturbances in the system parameters.

(d) SLDC shall also provide such a report to NERPC.

(e) For the purpose of analysis and reporting, telemetered data shall be archived with a granularity of not more than five (5) minutes and higher granularity for special events. Such data shall be stored by SLDC for at least fifteen (15) years and reports shall be stored for twenty-five (25) years for operational analysis.

7.7.2 Event reporting

Event reporting shall make available adequate data to facilitate event analysis:

(a) Immediately following an event (grid disturbance or grid incidence as defined in the CEA Grid Standards Regulation and amendments thereof) in the system, the concerned User or SLDC shall inform NERLDC through voice message.

(b) Written flash report shall be submitted to SLDC by the concerned User within the time line specified in Table below.

(c) Disturbance Recorder (DR), station Event Logger (EL) and Data Acquisition System (DAS) shall be submitted within the time line specified in Table below.

(d) SLDC shall report the event (grid disturbance or grid incidence) to CEA, NERPC and all regional entities within twenty-four (24) hours of receipt of the flash report.

(e) After a complete analysis of the event, the User shall submit a detailed report in the case of grid disturbance or grid incidence within one (1) week of the occurrence of event to SLDC.

(f) SLDC shall prepare a draft report of each grid disturbance or grid incidence, based on inputs including simulation results and analysis received from users, which shall be discussed and finalised at the SPCC, as per the timeline specified in Table below.

| 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 | hours | 2 hours | +7 days | +7 days | +60 days |
| 2 | Near miss event | 8 hours | 2hours | +7 days | +7 days | +60 days |
| 3 | GD-1 | 8 hours | 2 hours | +7 days | +7 days | +60 days |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | GD-2/GD- 3 | 8 hours | 2 hours | +7 days | +21 days | +60 days |
| 5 | GD-4/GD- 5 | 8 hours | 2 hours | +7 days | +30 days | +60 days |

*^The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per the CEA Grid Standards*

(g) The implementation of the recommendations of the final report shall be monitored by the Protection sub-committee of the NERPC. NLDC shall disseminate the lessons learnt from each event to all the RPCs for necessary action in the respective regions.

(h) Any additional data such as single line diagram (SLD) of the station, protection relay settings, HVDC transient fault record, switchyard equipment and any other relevant station data required for carrying out analysis of an event by RPC, NLDC, RLDC and SLDC, shall be furnished by the Users including RLDC and SLDC, as the case may be, within forty- eight (48) hours of the request. All Users shall also furnish high-resolution analog data from various instruments including power electronic devices like HVDC, FACTS, renewable generation (inverter level or WTG level) on the request of RPC, NLDC, RLDC and SLDC.

(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 SLDC, if connected to an intra-State system. The transient fault records and event logger data shall be submitted to the SLDC within twenty-four (24) hours of the occurrence of the incident. Generating stations shall submit one (1) second resolution active power and reactive power data recorded during oscillations to SLDC within twenty-four (24) hours of the occurrence of the oscillations.

(j) A monthly report on events of unintended operation or non-operation of the protection system shall be prepared and submitted by each User to SLDC within the first week of the subsequent month.

### 7.8 Load Crash

7.8.1 In the event of load crash in the system due to weather disturbance or any other reasons, the situation would be controlled by SLDC by the following methods in descending priority:

(i) Backing down of hydel stations for short period immediately;
(ii) Lifting of the load restrictions, if any;
(iii) Exporting the power to neighbouring regions;
(iv) Backing down of thermal stations with a time lag of 5-10 minutes for short period;

(v) Closing down of hydel units (subject to non-spilling of water and effect on irrigation); and

(vi) Backing down of Renewable Energy Power Plants.

The above methodology shall be reviewed by Operation and Co-ordination Committee from time to time.

7.8.2 While implementing the above, the system security aspects should not be violated as per relevant provisions under AEGC and IEGC.

# CHAPTER 8
# SCHEDULE AND DESPATCH CODE

## 8 Schedule and Despatch Code

### 8.1 Introduction

This chapter deals with the procedure for scheduling, injection and drawal of power by the Users through Intra-State Transmission System and the modalities for exchange of information and sets out the responsibilities of each User and SLDC in Scheduling and Despatch of energy.

### 8.2 Objective

The objective of this chapter is to deal with the procedures to be adopted for scheduling of ISGS, SSGS, IPPs, Joint Ventures, CGPs, Open Access Customers and REGS in detail and responsibility of SLDC in preparing and issuing daily schedule of dispatch/ drawal of generators and DISCOMs/Users respectively.

### 8.3 General Principles of Scheduling

8.3.1 All the scheduling will be done on 15-minute time block basis. For the purpose of scheduling, each day starting from 0000 hours (IST) to 2400 hours (IST) is divided into 96 time blocks each of 15 minutes duration. SLDC shall compile and intimate each DISCOM, the drawal schedule and to each SSGS and IPPs, the generation schedule in advance.

8.3.2 Users shall submit the following documents for commencement of scheduling of power:

i) Documents in support of the GNA or connectivity, by the Sellers and the Buyers, as applicable.
ii) Documents in support of the open access, by the Sellers and the Buyers, if applicable.
iii) Copies of valid contracts signed by Sellers and Buyers, for transactions other than collective transactions.
iv) Copy of allocation order, in case power is allocated by the State Government.
v) Grant of T-GNA with an effective date, by the buyers, if applicable

8.3.3 The State Load Despatch Centre shall be responsible for optimum scheduling and despatch of electricity, monitoring of real time grid operations through secure and economic operation of the State grid 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 Commission.

8.3.4 The Users connected exclusively to the intra-State transmission system shall be under the control area jurisdiction of SLDC for scheduling and despatch of electricity.

8.3.5 The Users connected to both inter-State transmission system and intra-State transmission system 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.

8.3.6 In case a User is connected to both inter-State transmission system and intra-State transmission system, the SLDC/ RLDC responsible for scheduling such User shall coordinate with the concerned RLDC or SLDC, as the case may be, for ensuring grid security.

8.3.7 Unless otherwise decided by the Commission, the Users that have already declared COD as on the date of coming into force of this Grid Code, 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 this Grid Code.

8.3.8 The entities participating in Ancillary Services must be capable of receiving the load set point signals from the NERLDC/SLDC or the NLDC as per CEA Technical Standards for Connectivity, or in terms of Ancillary Service Regulations, as applicable.

8.3.9 Declaration of Capacity by generating stations that are state entities:

i. The Generating Station shall declare ex-bus Declared Capacity limited to 100% MCR less auxiliary power consumption on day ahead basis.

ii. The hydro generating stations may declare ex-Bus Declared Capacity more than 100% MCR less auxiliary power consumption limited to overload capability during the high inflow periods. The high inflow period for this purpose shall be notified by SLDC.

iii. WS Seller. connected to the intra-state transmission system shall declare the available capacity on day ahead basis, as per the provisions of Clause 8.5 of these regulations.

iv. The State Load Dispatch Centre shall periodically check that the generating station is not manipulating the declaration of the Declared Capacity with the intent of making undue money through Fixed Charges or DSM.

v. The SSGS, IPPs and any other thermal generating station, other than WS sellers, shall be required to demonstrate the declared capability of its generating station as and when asked by the SLDC. In the event of the SSGS and IPPs failing to demonstrate the declared capability, it shall be treated as a mis-declaration for which charges shall be levied by SLDC and shall be recovered as per Detailed Procedure.

vi. 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 penalty shall increase in a geometric progression over a period of a month.

8.3.10 DISCOMs will give their requisitions on day ahead and real time basis as per individual Merit Order, i.e., in ascending order of the cost of energy (i.e., variable cost) of generating stations excluding hydro, nuclear and REGS.

8.3.11 The net drawal schedule of any DISCOM issued by SLDC, considering economic operation of State grid would be sum of ex-power plant schedules from different SSGS/ IPPs/JVs, share from ISGS and any bilateral exchange agreed by the DISCOMs and drawal/ injection on behalf of Open Access customers.

8.3.12 The generation schedule of each SSGS shall be sum of the requisitions made by each Distribution Licensee, restricted to their entitlement and subjected to maximum and minimum value criteria or any other technical constraints indicated by SLDC.

8.3.13 All the Intra State Users shall endeavour to maintain their Drawals/ injections in such a manner that they do not violate the limits on deviation volume as specified in the Assam Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2023 and amendments thereof.

8.3.14 The following specific points would be taken into consideration, while preparing the schedules:

(i) SLDC to check that the resulting power flows do not give rise to any transmission constraint. In case of any constraints, SLDC has to moderate the schedule to the required extent, under intimation to concerned Distribution Licensees and generating stations.

(ii) The state enitity generation stations shall declare the ramping rate alongwith declaration of day-ahead capacity in the following manner, which shall be accounted for in the preparation of generation schedules:

(a) 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;

(b) 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;

(c) 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;

(d) Renewable Energy generating stations shall declare a ramp up or ramp down rate as per CEA Technical Standards for Connectivity Regulations.

8.3.15 For optimum Utilization of Hydro Energy:

(i) 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 (up to 10% or such other limit as certified by the OEM and approved by CEA) minus auxiliary consumption, corrected for the reservoir level. 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.

(ii) During high inflow and water spillage conditions, the SLDC 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 (i) of this clause, subject to the availability of margins in the transmission system.

8.3.16 Scheduling of WS seller and ESS by QCA:

(i) The renewable energy generating station(s) or Projects based on energy storage system(s) connected at a particular InSTS substation or at multiple InSTS substations located in the State may appoint a QCA on their behalf to coordinate and facilitate scheduling for such generating stations or energy storage system(s). The responsibility of QCA is listed at Appendix-L to these regulations.

(ii) SLDC 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 that are regional entities, within three (3) months of notification of these regulations for approval of the Commission.

(iii) The QCA shall be registered with the SLDC.

(iv) QCA registered with the SLDC shall, on behalf of wind, solar or renewable hybrid generating stations or Energy Storage System shall:

(a) Coordinate and facilitate scheduling of power with the SLDC; and;

(b) Undertake commercial settlement of deviations with the SLDC in accordance with the DSM Regulations.

(c) Submit a copy of the consent to the SLDC certifying that QCA shall undertake all operational and commercial responsibilities on behalf of generating stations as per the AERC Regulations.

(v) The concerned wind, solar or renewable hybrid generating stations including energy storage systems shall indemnify the SLDC for any act of commission or omission on the part of QCA including compliance with the Grid Code and settlement of its financial liability in the pooled account.

(vi) Contract between the generating stations and QCA shall invariably contain provisions for internal dispute resolution, and any disputes arising between the generating stations and QCA shall be settled in accordance with the said mechanism.

(vii) For Optimum Utilization of Wind/ Solar generators, Hybrid of Wind and Solar Generating Stations and Energy Storage System (ESS) shall mandatorily provide to SLDC, in a format as specified by SLDC, the technical specifications of their plants at the beginning and whenever there is any change. The data relating to power system parameters and weather-related data as applicable shall also be mandatorily provided by such generators to SLDC in real time.

8.3.17 Adherence to Schedule:

Each state entity shall regulate its generation or demand or both, as the case may be, so as to adhere to the schedule of net injection into or net drawal from the intra-State transmission system.

8.3.18 Area Control Error:

The State Load Despatch Centre and other drawee regional entities shall keep their Area Control Error close to zero (0) by way of rescheduling, deploying reserves and automatic demand management scheme, as applicable.

## 8.4 Responsibilities of State Load Despatch Centre

The SLDC, in discharge of its functions under the Act and for stable, smooth and secure operation of the integrated grid, shall be responsible for the following within its control area:

i. Forecasting demand for its control area for each time block on day-ahead and intra-day basis;

ii. Forecasting of generation from wind/ solar generators, Hybrid of Wind and Solar Generating Stations and Energy Storage System (ESS) under its jurisdiction based on inputs received from the generators for each time block on day-ahead and intra-day basis:

Provided that such forecasts may be used by the wind /solar generators, Hybrid of Wind and Solar Generating Stations and Energy Storage System (ESS) at their own risk and discretion along with all commercial liabilities arising out of it;

iii. Scheduling and despatch for the entities in the State control area in accordance with contracts;

iv. SLDC shall certify the Declared Capacity of generating stations/units, which is under the purview of SLDC and shall be binding on all the participants;

v. Balancing demand and supply to minimize Area Control Error (ACE) for the State;

vi. Maintaining and despatching reserves as shall be decided by NERPC as per guidelines of central agencies;

vii. Implementing SCED and SCUC as shall be directed by NLDC/NERPC as per guidelines of central agencies;

viii. Declaring Total Transfer Capability (TTC) and Available Transfer Capability (ATC) in respect of import and export of electricity of its control area with inter-State transmission systems in coordination with the Central Transmission Utility, State Transmission Utility and concerned RLDC and revising the same from time to time based on grid conditions. Assessment of TTC and ATC shall be done on a continuous basis at least Eleven (11) months (M-12) in advance and revised based on contingencies from time to time with addition of new elements (commissioned or to be commissioned). SLDC shall submit morning peak, evening peak, day and night off-peak node-wise load data (MW and MVAR) for 132 kV and above for the preparation of scenarios for computation of TTC and ATC by NERLDC and NLDC. STU in co-ordination with Distribution Licensees and generating stations shall submit this data to SLDC by 5$^{th}$ of M-12 month and may revise on M-6 (by 5$^{th}$ day) and M-1 (by 5$^{th}$ day) months. TTC and ATC calculations for the State shall be done based on procedure for the transfer capability assessment methodology published by NLDC.

**8.5 Scheduling Process**

8.5.1 By 6 AM on 'D-1' day, each Intra-State SSGS/IPPs/REGS will intimate SLDC, station-wise ex-power plant MW and MWH capabilities foreseen for the next day 'D'. i.e., between 0000 hours to 2400 hours, at 15-minute intervals.

The Generating Stations shall submit the following information:

(i) Generating Station based on coal and lignite:
- (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.

(ii) Generating Station based on hydro energy:
- i. Time block-wise ex-bus declared capacity.
- ii. MWh capability for the day.
- iii. Ex-bus peaking capability in MW and MWh.
- iv. Time block-wise Ramp up rate (MW/min) for on-bar capacity.
- v. Time block-wise Ramp down rate (MW/min) for on-bar capacity.
- vi. Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity.
- vii. Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.
- viii. Unit-wise maximum MW along with probable combination of unit maximum in case adequate water is not available.

(iii) Generating station based on gas or combined cycle generating station:
- (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 (fuel-wise) 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.

(iv) The renewable energy generating station based on wind/ solar, hybrid of wind and solar, 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. The source-wise breakup of aggregate available capacity of the pooled generation shall also be furnished.

(v) ESS including pumped storage plant, individually or represented by the 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. The source-wise breakup of aggregate available capacity of the pooled generation shall also be furnished.

(vi) The availability declaration by generating station shall have a resolution of two decimal (0.01) MW and three decimal (0.001) MWh.

8.5.2 The entitlement of each Beneficiary or Buyer, from generating stations, shall be in accordance with Regulation 49.1.(b) of Indian Electricity Grid Code and amendments thereof.

8.5.3 NERLDC shall declare share of each Beneficiary or Buyer for 0000 hours to 2400 hours of 'D' day, by 7 AM on 'D-1' day.

8.5.4 SLDC will compile the generator-wise availability for ISGS/ other agreements /SSGS/ IPPs/ REGS entitlement of each Beneficiary or Buyer for 'D' day at 15-minute interval and intimate the same by 07:15 AM on 'D-1' day.

8.5.5 By 07:30 AM of 'D-1' day, each beneficiary or buyer will furnish requisition to SLDC in each ISGS, other agreements, Intra-State, SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of 'D' day.

8.5.6 By 8 AM of 'D-1' day, SLDC shall convey the requisition of the State to NERLDC from ISGS/ other agreements/ SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of 'D' day.

8.5.7 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 Grid Code, shall subject to technical constraints, duly factor in merit order of the generating stations with which intra-State entities has entered into contract(s) for drawal of power:

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.

8.5.8 NERLDC shall check if drawal schedules as requisitioned can be allowed based on available transmission capability:

Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated in proportion depending upon the transmission constraint, whether it is within the region or from outside the region, as the case may be. The same shall be intimated to the drawee entities by 8:15 AM on 'D-1' day.

8.5.9 The Intra-State Entities shall revise their requisition for drawal schedule based on availability of transmission corridors by 8:30 AM on 'D-1' day.

8.5.10 NERLDC shall issue final drawal schedules and injection schedules for the State by 9 AM on 'D-1' day.

8.5.11 In case a generating station other than REGS intends to replace its schedule by power supplied from REGS, it shall intimate the quantum and source of power by which it intends to replace the power already scheduled by 9:15 AM on 'D-1' day.

8.5.12 Based on the entitlement or otherwise, SLDC on behalf of intra-State entities which are T-GNA grantees, shall furnish time block-wise requisition for drawl, to the NERLDC in accordance with contracts by 9.15 AM of 'D-1' day.

8.5.13 RLDC and subsequently SLDC, shall incorporate the request from the above said generating station and finalize the injection and drawal schedules by 9:45 AM on 'D-1' day.

8.5.14 RLDC shall release the balance corridors after finalisation of schedules for day ahead collective transactions.

8.5.15 Scheduling of Collective Transactions as per IEGC:

i. Power Exchange(s) shall open bidding window for day ahead collective transactions and TRAS from 10:00 AM to 11:00 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 11.45 AM of 'D-1' day.

iii. NLDC shall validate the same from system security point and inform the Power Exchange(s) 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(s) 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.

8.5.16 RLDC shall release balance corridors after finalisation of schedules under day ahead collective transactions by 1:00 PM of 'D-1' day.

8.5.17 RLDC/ SLDC shall process exigency applications received till 1:00 PM of 'D-1' day for 'D' day by 2:00 PM of 'D-1' day.

8.5.18 RLDC, and subsequently SLDC, shall update the availability of balance transmission corridors, if any, after finalisation of schedules for exigency applications by 2:00 PM of 'D-1' day on its website. The balance transmission corridor may be utilised by way of revision of schedule, under any contract within its GNA or for exigency applications or in real time market on first-come-first-served basis.

8.5.19 Scheduling of transactions in Real-Time Market (RTM), as per IEGC:

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 'D' day shall open from 22:45 hours to 23:00 hours of 'D-1' for the delivery of power for the first two time-blocks of 1st hour of 'D' day, i.e., 0000 hours to 0030 hours, 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 Exchange(s) shall clear the real-time bids from 23:00 hours till 23:15 hours 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 hours, for scheduling.

8.5.20 NLDC shall finalise schedules under real time market (RTM) by 23:30 hours of 'D-1' day and RLDC, subsequently SLDC, shall publish the final schedules for dispatch by 23:35 hours of 'D-1'day. The scheduled finalized by SLDC shall have the following:

- Ex-power plant generation schedule of SSGS/IPPs and other State generators including wind/ solar generators, Hybrid of wind and solar Generating Stations and Energy Storage System (ESS).
- Drawal schedule of each entity in MW for each time block, along with break-up of (a) schedule from each of the sellers, (b) schedule of injection to InSTS and (c) injection or drawal schedule under collective transaction, on the basis of information received from the Power Exchange (s) or NERLDC, as applicable and as specified in the IEGC.

**8.6 Rules for revision in schedule**

8.6.1 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 with immediate effect by the SLDC (in co-ordination with Regional Load Despatch Centre, as applicable) keeping in view the transaction which is likely to relieve the threat to grid security, in conformity with the IEGC, 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.

8.6.2 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 SLDC shall revise the schedules:

Provided that generation and drawal schedules revised by the SLDC shall become effective from 7th block or 8th block depending on time block in which schedule has been revised as first time block.

8.6.3 In case of contingencies such as critical loading of lines, transformers, abnormal voltages or threat to system security, the following steps as considered necessary, may be taken by SLDC:

i. Issue directions to concerned entities to adhere to the schedules;
ii. Switching on/off pump storage plants operating in pumping mode;
iii. Despatching emergency demand response measures;
iv. Direct the state entities to increase or decrease their drawal or injection by revising their schedules and such directions shall be immediately acted upon;
v. Deployment of ancillary services, in co-ordination with NERLDC/NLDC as applicable

8.6.4 Whenever SLDC revises final schedules due to reasons of grid security or contingency, brief reasons shall be informed immediately to the concerned entity followed by a detailed explanation to be posted on SLDC website within 24 hours.

8.6.5 Any verbal directions by SLDC shall be confirmed in writing as soon as possible latest within twenty four hours.

8.6.6 Revision of schedules on request of buyers which are GNA grantees, in line with IEGC:

i. SLDC on behalf of intra-state entities, regional entity ESSs as drawee entities, beneficiaries, regional entity buyers or cross-border buying entities may revise their schedules under GNA as per sub-clauses (ii) and (iii) 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 or partial outage.

ii. The request for revision of scheduled transaction for 'D' day, shall be allowed subject to the following:

a) 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.

b) 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 the IEGC and amendments therof.
Provided that downward revision of schedules by the buyers for 'D' day, after 1430 hrs on 'D-1' day in the generating station is permissible only for beneficiaries which have scheduled above their respective share of minimum turndown level in the generating station:
Provided also that downward revision by such beneficiaries, which have scheduled above their respective share of minimum turndown level in the generating station, shall be permissible limited to a quantum such that overall schedule of the generating station is at least at Minimum turndown level. The downward revision of schedules by such beneficiaries for 'D' day, after 1430 hrs on 'D-1' day shall be permissible on a pro-rata basis of the power scheduled above the minimum turndown level of their share at 1430 hrs of 'D-1' day.

c) 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.

iii. Based on the request for revision in schedule made as per sub-clauses (i) and (ii) of this clause, 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 SLDC (or RLDC, when RLDC approval is required) to be the first one.

iv. While finalizing the drawal and despatch schedules, in case any congestion is foreseen in the intra/inter State transmission system or technical constraints of a generating station, the SLDC/NERLDC shall moderate the schedules as required, under intimation to the concerned entities.

**8.7 Additional factors to be considered while finalizing schedule**

8.7.1 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.

(b) Certification of such grid disturbance and its duration shall be done by the NERLDC and the notice posted by the NERLDC at its website, to this effect, shall be considered as declaration of the grid disturbance by RLDC. SLDCs shall take action for restoration of grid to normalcy, in coordination with NERLDC, if required. All state entities shall take note of the grid disturbance and take appropriate action at their end.

(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 state entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the Deviation and Ancillary Service 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.

(d) The scheduled generation of all the affected regional entity generating stations supplying power under collective transactions shall be deemed to have been revised to be equal to their actual generation. Such regional entity generating stations shall refund the charges received towards such scheduled energy to the Deviation and Ancillary Service Pool Account.

(e) Energy and deviation settlement for the period of such grid disturbance causing disruption in injection or drawal of power shall be done by the SLDC:

Provided that generation and drawal schedules revised by the RLDC, subsequently by SLDC, shall become effective from 7th block or 8th block depending on block in which schedule has been revised as first block.

8.7.2 The generation schedules and drawl schedules shall be accessible to the state 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 state entity generating stations and drawal schedule of the buyers/beneficiaries shall be issued by the concerned RLDC. These schedules shall be the basis for commercial accounting.

8.7.3 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 estimated time of restoration of the unit to SLDC. 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 8.6 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 8.6 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 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.

8.7.4 Revision of Declared Capacity and schedule of a generating station or ESS (as an injecting entity) shall be allowed only in case of bilateral transactions and not in case of collective transaction as per following details:

(a) The generating station (other than lignite, gas based thermal generating station, and hydro generating station) or ESS (as an injecting entity) shall be allowed a maximum of 4 (four) revisions of Declared Capacity and schedule in a day subject to a maximum of 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:

Provided that SLDC/NERLDC (as applicable) may allow upward revision of DC beyond the above limit keeping in view grid requirements.

(b) The generating station based on lignite, gas, or hydro generating station shall be allowed 6(six) revisions of Declared Capacity and schedule in a day subject to a maximum of 120 (One hundred twenty) revisions during a month, due to reasons such as a partial outage of the unit or water availability for hydro generating stations or fuel quality or variations in the supply of gas for gas generating stations or any other technical reason to be recorded in writing:

Provided that SLDC/NERLDC (as applicable) may allow upward revision of DC beyond the above limit keeping in view grid requirements

8.7.5 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 clause8.6.6.iiiof this Regulation.

8.7.6 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 clause 8.6.6.iii of this Regulation.

8.7.7 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.

8.7.8 Discrepancy in schedule

i. All state entities, open access customers, injecting entities and drawee consumers shall closely check their transaction Schedule and point out errors, if any, to the SLDC.

ii. The final schedules issued by SLDC shall be open to all state entities and other state open access entities for any checking and verification, for a period of 5 days. In case any mistake or omission is detected, the SLDC shall make a complete check and rectify the same.

8.7.9 Margins for primary response:

For the purpose of ensuring primary response, SLDC (in co-ordination with NERLDC, wherever required), 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 SLDC (in co-ordination with NERLDC, wherever required), 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 (i) clause 8.3.15 of these regulations, during high inflow periods to avoid spillage.

8.7.10 Security Constrained Unit Commitment (SCUC)

i. The objective of Security Constrained Unit Commitment (SCUC) is to commit a generating station or unit thereof, for the maximisation of reserves in the interest of grid security, without altering the entitlements and schedule of the buyers of the said generating station in the day ahead time horizon.

ii. Reserves shall be procured and deployed in accordance with the Ancillary Services Regulations, and SCUC shall supplement such procurement of reserves under certain conditions, as specified in this Regulation or the IEGC, as applicable.

iii. SCUC shall be undertaken if the NLDC, in coordination with RLDCs and based on an assessment of the power system condition, anticipates that there is likely to be a shortage of reserves despite efforts made to procure such reserves in accordance with the Ancillary Services Regulations.

iv. SLDC and other state entities shall carry out necessary activities in line with the Detailed Procedure specified by the NLDC or NERLDC, as the case may be.

8.7.11 UNIT SHUT DOWN (USD)

i. The generating stations or units thereof, identified by NLDC in co-ordination with RLDC/SLDC, as the case may be, as per subclause (c ) of clause (4) of Regulation 46 of the IEGC 2023 and amendments thereof, 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 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 honoring of rights of the original beneficiaries of the said generating station or unit thereof from which supply is arranged; or (c) through SCED as per the Detailed Procedure specified by NLDC in this regard.

iii. In case of emergency conditions, for reasons of grid security, a generating station or unit thereof, which is under USD, as 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 as per the Detailed Procedure specified by NLDC in this regard.

iv. Once a generating station is brought on bar as per clause (iii) of this Regulation, it shall be treated as a unit under SCUC and scheduled and compensated as per the relevant regulations of the IEGC.

8.7.12 Security Constrained Economic Despatch (SCED)

i. The objective of Security Constrained Economic Despatch (SCED) is to optimise generation despatch after gate closure in the real time market and after finalisation of schedules under RTM, by incrementing generation from the generating stations with cheaper charge and decrementing commensurate generation from the generating station with higher charge, after considering the operational and technical constraints of generation and transmission facilities.

ii. As provided in the IEGC. NLDC shall be the nodal agency for implementing Security Constrained Economic Despatch (SCED) through RLDCs which shall be as per the detailed procedure issued by the NLDC or NERLDC, as the case may be.

8.7.13 Oversight of Injection and Drawal:

SLDC shall periodically review the over drawal from or under injection into the grid. In case of persistent over drawal or under injection, the matter shall be reported to the GCMC for necessary action. If this still persists after being taken up at the GCMC, it shall be reported to the Commission the matter with recommendation.

## 8.8 Scheduling from alternate source of power by a generating station

8.8.1 A generating station may supply power from alternate source in case of Unit Shut Down (USD) or forced outage of unit(s). This facility shall also be available to a generating station other than REGS replacing its scheduled generation by REGS, irrespective of whether such identified sources are located within or outside the premises of the generating station or at a different location.

8.8.2 The methodology for scheduling of power from alternate sources covered under Unit Shut Down (USD) or forced outage of unit(s) shall be as per the following steps:

(a) The generating station may enter into contract with alternate supplier under bilateral transaction or collective transaction.

(b) In case of bilateral transaction, the generating station shall request SLDC to schedule power from such alternate supplier to its beneficiaries, which shall become effective from 7th or 8th time block, as the case may be, in line with Clause 8.6 of this regulation.

(c) The power scheduled from alternate supplier shall be reduced from the schedule of the generating station.

(d) In case of alternate supply is arranged through collective transactions, the transacted quantum shall be reduced from the scheduled generation of the generating station.

(e) The generating station shall not be required to pay the transmission charges and losses for such purchase of power to supply to the buyer from alternate sources.

(f) The generating station may also request the concerned RLDC to arrange alternate supply through SCED in accordance with the relevant provisions of the IEGC.

8.8.3 The methodology for scheduling of power from alternate sources for a generating station other than REGS replacing its scheduled generation by power supplied from REGS shall be as per the following steps:

(a) The generating station shall enter into contract with REGS for supply of power from alternate sources.

(b) The generating station shall request SLDC to schedule power from such alternate source to its beneficiaries, which shall become effective from 7th or 8th time block, as the case may be.

(c) The power scheduled from alternate source shall be reduced from the schedule of the generating station.

(d) The generating station shall not be required to pay the transmission charges and losses for such purchase and supply from alternate sources to the buyer.

(e) In case of a generating station whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from an alternate source, shall be subject to sharing of net savings as specified in the Assam Electricity Regulatory Commission (Terms and Conditions for Multi Year Tariff) Regulations, 2024 and amendments thereof.

(f) In case of a generating station other than whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from an alternate source shall be in accordance with the contract with the buyer and in the absence of a specific provision in the contract, in terms of mutual consent including on sharing of net savings between the generating station and the buyer.

**8.9 Minimum Turndown Level for operation of Thermal Generating Stations**

8.9.1 The minimum turndown level for operation in respect of thermal generating units connected to STU network and which is in control area of SLDC shall be 55% of the MCR of the said unit or such other minimum power level as specified in the CEA Flexible Operation Regulations as amended from time to time, whichever is lower:

Provided that the Commission may, through an order, fix a different minimum turndown level of operation in respect of specific unit(s) of a 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 Regulation:

Provided also that the thermal generating stations whose tariffs are adopted under Section 63 of the Act, shall be compensated for part load operation, i.e., 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 separately.

Provided further that the thermal generating stations whose tariffs are determined under Section 62 of the Act by the Commission, shall be compensated for part load operation, as per provisions of applicable Regulations of AERC, unless separate notification is issued by the Commission.

**8.10 Data Registration**

User shall provide SLDC with data for this chapter as specified in Data Registration Code.

# CHAPTER 9
# FREQUENCY AND VOLTAGE MANAGEMENT CODE

## 9 Frequency and Voltage Management Code

### 9.1 Introduction

This chapter describes the method by which all Users of the State Transmission System shall coordinate with SLDC and STU in contributing towards effective control of the system frequency and managing the grid voltage.

State Transmission System normally operates in synchronism with the National Grid and NERLDC has the overall responsibility of the integrated operation of the North-Eastern Regional Power System. The constituents of the Region are required to follow the instructions of NERLDC for backing down generation, regulating loads, MVAr drawal, etc., to maintain the system frequency and grid voltage.

SLDC shall accordingly instruct SSGS to regulate generation/export and hold reserves of active and reactive power within their respective declared parameters. SLDC shall also instruct the DCC of the distribution licensees to regulate the load as may be necessary to meet the objective.

### 9.2 Objective

The objectives of this chapter are as follows:

- To define the responsibilities of all Users in contributing to frequency and voltage management.
- To define the actions required to enable SLDC and STU to maintain State Transmission System voltages and frequency within acceptable levels in accordance with IEGC/ AEGC.

### 9.3 Frequency Control

9.3.1 The rated frequency of the system shall be 50.000 Hz and shall normally be regulated within the allowable band of 49.900-50.050 Hz in line with IEGC. The frequency shall be measured with a resolution of +/- 0.001 Hz by SLDC and such frequency data measured every second shall be archived by SLDC.

9.3.2 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.

9.3.3 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 SLDC so that the grid frequency is maintained and remains within the allowable band.

9.3.4 Falling frequency

SLDC shall take appropriate action to issue instructions, in co-ordination with NERLDC to arrest the falling frequency and restore it, within permissible range. Such instructions may include dispatch instruction to generators under control area of SLDC and/or instruction to DCC of DISCOMs/ Users to reduce load demand manually and/or through automatic load shedding.

9.3.5 Rising Frequency

SLDC shall take appropriate action to issue instructions to the generators under its control in co-ordination with NERLDC, to arrest the rising frequency and restore frequency within permissible range. SLDC shall also issue instructions to DISCOMs/ Users in coordination with NERLDC to lift Load shedding, in any persist.

**9.4 Reserve**

9.4.1 **There shall be reserves as under:**

(a) Primary, Secondary and Tertiary reserves:

(i) Primary, Secondary and Tertiary reserves shall be deployed for the purpose of frequency control, reducing area control error and relieving congestion.

(ii) The response under Primary reserve shall be provided as per this Grid Code.

(iii) Secondary reserves including automatic generation control and demand response shall be deployed in the control area as per these regulations or the the AERC (Ancillary Services) Regulations, 2024, as amended from time to time.

(iv) Tertiary reserves shall be deployed in the control area as per these regulations or the AERC (Ancillary Services) Regulations, 2024, as amended from time to time.

(b) Black Start reserves:

Generating stations having black start capability, ESS, and HVDC Station based on

VSC, shall be identified by SLDC at the State level, to act as black start reserves.

(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 drawal.

9.4.2 The reserves shall be operated as Ancillary Services, namely (a) Primary Reserve Ancillary Service (PRAS); (b) Secondary Reserve Ancillary Service (SRAS); (c) Tertiary Reserve Ancillary Service (TRAS); (d) Black Start Ancillary Services; and (e) Voltage Control Ancillary Services.

9.4.3 The mechanism of procurement and deployment of Primary Reserves Ancillary Service (PRAS) shall be as specified in this Grid Code or the AERC (Ancillary Services) Regulations, 2024, as the case may be.

9.4.4 The mechanism of procurement, deployment and payment of Secondary Reserve Ancillary Service and Tertiary Reserve Ancillary Service shall be as per these regulations or the AERC (Ancillary Services) Regulations, 2024.

9.4.5 The primary response of the generating units shall be verified by SLDC during grid events. The concerned generating station shall furnish the requisite data to SLDC within two days of notification of reportable event.

**9.5 Control Hierarchy**

9.5.1 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). To maintain the minimum inertia, the NLDC may, if required, bring quick start synchronous generation on bar and reschedule generation including curtailment of wind, solar and wind-solar hybrid generation, in coordination with the respective RLDC and SLDC. The compensation for such quick start synchronous generation shall be included in the procedure to be prepared by SLDC in line to NLDC and approved by the appropriate Commission.

9.5.2 Primary Control

(a) Primary control is local automatic control in a generating unit or energy storage system or demand side resource for the purpose of adjusting its active power output or consumption, as the case may be, in response to frequency excursion. Primary control is the immediate automatic control implemented through turbine speed governors or frequency controllers.

(b) Primary control shall be provided by the Primary Reserves Ancillary Service (PRAS).

(c) The minimum quantum of PRAS required for reference contingency shall be declared by SLDC in consultation with NLDC at the start of each financial year.

(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 Regulations and are mandated to provide PRAS. The generating stations and units thereof with governors shall be under Free Governor Mode of Operation.

(e) As per IEGC, NLDC may also identify other resources such as ESS and demand resource to provide PRAS, in consultation with SLDC, for which PRAS providers shall be compensated in accordance with the Ancillary Services Regulations.

(f) The minimum All India target frequency response characteristics (FRC) shall be estimated and based on such target FRC, the frequency response obligation of each control area shall be assessed by NLDC (in consultation with SLDC, if required), giving due consideration to generation and load within each control area and details as given in Table below. The same shall be informed to all control areas by 15th of March every year for the next financial year.

(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 Regulations. The primary response requirement of various types of generating units shall be as mentioned below:

| **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) |
| WS Seller | Capacity of Generating | As per CEA Technical |

| | | |
|---|---|---|
| *(Commissioned after the date as specified in the CEA Technical Standards for Connectivity)* | station more than 10 MW and connected at 33 kV and above | Standards for Connectivity Regulations. |

Provided that:

i) WS Sellers commissioned after the date as specified in CEA Technical Standards for Connectivity Regulations, shall have the option to provide primary response individually through ESS or through a common ESS installed at its pooling station.

ii) 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.

(h) All generating stations mentioned in above table 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 SLDC.

(i) All generating stations, including the WS seller as mentioned in above table, shall have the capability of reducing output at least by 5% or 10%, as applicable, of their operating level and up to 5% or 10% of their MCR, as applicable, limited to the minimum turndown level when the frequency rises above the reference frequency and thus, providing primary response, whenever condition arise. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining permission from SLDC.

(j) 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. 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.

(k) The thermal and hydro generating units shall not resort to Valve Wide Open (VWO) operation to make available margin for providing governor action.

(l) The Primary Reserves Ancillary Service (PRAS) shall start immediately when the frequency deviates beyond the dead band as specified in above Regulation 9.5.2(j) and shall be capable of providing its full PRAS capacity obligation within 45 seconds and sustaining at least for the next five (5) minutes.

(m) SLDC shall assess the frequency response characteristics and share the assessment with the NERLDC along with high resolution data of at least one (1) second for generating stations and energy storage systems and ten (10) seconds for the State control area.

(n) As stated in IEGC, the actual frequency response characteristics of all the control areas within its region and the performance of each control area in providing frequency response characteristics for each reportable shall be calculated by concerned RLDC .

(o) As stated in IEGC, NLDC in consultation with RLDC/SLDC shall calculate the actual frequency response characteristics at national level by factoring in the FRC of all regions and shall also calculate the FRC for cross-border control areas.

(p) SLDC shall grade the median Frequency Response Performance annually, considering at least ten (10) reportable events, in coordination or as directed by NLDC/NERLDC. In case the median Frequency Response Performance is less than 0.75 as calculated, NLDC/RLDC/SLDC, as the case may be, after analysing the FRP, shall direct the concerned entities to take corrective action. All such cases shall be reported to the NERPC for its review.

9.5.3 **Secondary Control :**

(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.

(b) Secondary Control shall be provided by a generating station or an entity having energy storage resource 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, as a Secondary Reserve Ancillary Service (SRAS) Provider, as specified in the the the AERC (Ancillary Services) Regulations, 2024, as amended from time to time.

(c) Secondary control signals shall be automatically generated from NLDC and shall be transmitted to SRAS Providers through the concerned RLDC/SLDC, as applicable, 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 the review of the performance of SRAS. Provided that as and when the bi-directional communication system of SRAS providers with RLDC is fully established, secondary control signals shall be automatically generated from the respective RLDC. SLDC shall take actions for the implementation of SRAS, as and when directed by NLDC/NERLDC.

(d) As specified in the IEGC, ACE of each State or Regional control area, shall be auto calculated at the control center 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 sub-clauses (e) and (f) respectively of this clause as per the following formula:

$ACE = (Ia - Is) - 10 * Bf * (Fa - Fs) + Offset$

Where, Ia = Actual net interchange in MW (positive value for export)

Is = Scheduled net interchange in MW (positive value for export)

Bf = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

Fa = Actual system frequency in Hz

Fs = Schedule system frequency in Hz

Offset = Provision for compensating measurement error

(e) Frequency Bias Coefficient (Bf) shall be declared by SLDC for the State, in consultation with NLDC/NERLDC. Frequency Bias Coefficient shall normally be based on the median Frequency Response Characteristics (FRC) observed during the previous financial year of each control area and refined from time to time.

(f) Offset shall be used to account for measurement errors and shall be decided by SLDC for the State control area.

(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 Secondary control may be suspended due to system maintenance or grid security or for any other reasons to be recorded in writing:

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.

(h) Schedule system frequency (Fs) shall be a reference frequency of 50 Hz unless otherwise specified by NLDC under certain conditions to be recorded in writing.

(i) SLDC shall compute the ACE of the state control area in real time based on telemetered data. ACE data shall be archived at an interval of 10 seconds or less. SLDC shall share the data with the NERLDC and NLDC.

(j) The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds of receipt of the signal 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.

(k) With due regard to the requirement of planning reserve margin and resource adequacy referred to in Chapter 4 of these regulations and based on the following methodologies, the secondary reserve capacity requirements shall be estimated by NERLDC for north-eastern regional control area:

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 (SLDC shall refer to and take necessary action, if any, in line with the detailed procedure prepared by NERLDC/NLDC), 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

Such other methodology as may be stipulated by NLDC as per IEGC.

(l) Unless otherwise specified by the Commission through separate order/regulation, the methodology specified in sub-clause (k) of this clause shall be adopted by the SLDC to estimate the secondary reserve capacity requirement in the State control area.

(m) The reserve capacity requirement as per the methodology mentioned in sub-clauses (k) and (l) of this clause shall be estimated by RLDC/SLDC, as the case may be, respectively by 15th January every year for the next financial year and submitted to NLDC.

(n) All India secondary reserve capacity requirement for the State control area shall be as estimated by NLDC based on reference contingency and other factors such as forecast errors.

(o) All India secondary reserves capacity, to be maintained at State control area shall be as allocated by NLDC, based on the estimated reserves as per sub-clauses (k) and (l) of this clause and published on their website.

(p) As per IEGC, NLDC through RLDCs shall re-assess the quantum of requirement of secondary reserves required at the state control area three days before the day of scheduling and communicate the same to the respective SLDC.

(q) 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 as published by NLDC in terms of sub-clauses (o) and (p) of this clause, and inform the same to the concerned RLDC and NLDC two days before the day of scheduling. The modalities for information exchange and timelines in this respect shall be as per the detailed procedure to be issued by NLDC.

(r) The replenishment of primary reserves shall be as re-assess by NLDC through RLDCs in line with IEGC. The re-assessment of quantum of the requirement for secondary reserves at the regional level shall be 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.

(s) As specified in the Ancillary Services Regulations, NLDC through RLDCs shall further re-assess the quantum of the requirement for secondary reserve at the regional level on day ahead basis and also on a real time basis.

(t) If the 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 State and allocate the cost of procurement of such capacity to the State based on the methodology as per the detailed procedure to be issued by the NLDC, approved by CERC.

(u) NLDC, RLDC, SLDC shall indicate the shortfall in secondary reserves, if any, and announce emergency alerts for such periods.

(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.

(w) All thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW shall make arrangements to enable automatic operation of the plant from the NERLDC/SLDC, as the case may be, 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.

(x) All renewable energy generating stations and ESS shall be equipped with the facility to control active power injection in accordance with the CEA Connectivity Standards and the communication system shall be established in accordance with the CEA Technical Standards for Communication.

(y) SRAS shall have a bi-directional communication system along with metering and SCADA telemetry in place as per the requirements stipulated in the Detailed Procedure issued under the Ancillary Service Regulations.

9.5.4 **Tertiary Control:**

(a) Tertiary reserve requirement for the State control area, shall be as estimated by NLDC with due regard to the requirement of planning reserve margin and resource adequacy as referred to in the IEGC, so as to take care of contingencies and to cater to the need for replacing secondary reserves, published on its website by 25th January every year in line with IEGC, and will be implemented for the next financial year from 1st April onwards by the State control areas.

(b) The re-assessment the quantum of requirements for tertiary reserves required at the state control area three days before the day of scheduling shall be as done by NLDC through RLDC and communicated to the SLDC.

(c) The State control area shall ensure the availability of the quantum of tertiary reserve with due regard to the tertiary reserves estimated and allocated for the State as published by NLDC in terms of sub-clauses (b) and (c) of this clause, and inform the same to the concerned RLDC and NLDC two days before the day of scheduling. The modalities for information exchange and timelines in this respect shall be as per the detailed procedure to be issued by NLDC.

(d) Each State control area shall ensure availability of the quantum of tertiary reserve at the State control area on day ahead basis with due regard to the tertiary reserves estimated and allocated for that State by NLDC in terms of sub-clause (b) and (c) of this clause, and inform the same to the concerned RLDC and the NLDC.

(e) As specified in IEGC, NLDC through RLDCs shall re-assess the quantum of requirements for tertiary reserve at the regional level with due regard to the estimation inter alia of tertiary reserves maintained at State control area and the need to replace secondary reserves, three days before the day of scheduling inter alia to identify reserves to be brought on bar under SCUC.

(f) As specified under the Ancillary Services Regulations, NLDC through RLDCs shall further re-assess the quantum of the requirement for tertiary reserve at regional level on day ahead basis and also on a real time basis.

(g) If the State falls short of maintaining tertiary reserve capacity as allocated to it in terms of sub-clauses (b) or (c) of this clause , whichever is lower, the NLDC through RLDC shall procure such tertiary reserve capacity on behalf of the said State under advance intimation to the State and allocate the cost of procurement of such capacity to that State based on the methodology as per the detailed procedure issued by the NLDC approved by the CERC.

(h) Tertiary reserves shall be procured by the NLDC from a generating station or an entity having energy storage resourced 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.

(i) Tertiary reserves to be provided by the TRAS provider shall be capable of providing TRAS within fifteen (15) minutes of despatch instructions from NERLDC or SLDC, as the case may be, and shall be capable of sustaining the service for at least the next 60 minutes. TRAS shall be activated and deployed by the NERLDC or SLDC, as the case may be, on account of the following events:

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 20 MW, or in respect of the State such other volume limit as may be specified by the Commission;

ii. Generation unit or transmission line outages;

iii. Any such other event affecting the grid security.

(j) The quantum of reserves procured by the State control area shall be communicated to the NERLDC.

(k) The modalities for information exchange and timelines in respect of tertiary reserves shall be as per detailed procedure prepared by NLDC.

9.5.5 The control area wise performance of SRAS, TRAS providers shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.

**9.6 Voltage Management**

9.6.1 Users using the State Transmission System shall make all possible efforts to ensure that the grid voltage always remains within the limits specified in IEGC and amended thereof. The specified limit of voltage specified in IEGC are reproduced below:

| **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 and subsequent updations.*

9.6.2 STU and/or SLDC shall carry out load flow studies based on operational data available from time to time, to predict where voltage problems may be encountered and to identify appropriate measures to ensure that voltages remain within the defined limits. On the basis of these studies, SLDC shall instruct the generators within its control area to maintain specified voltage level at interconnecting points. SLDC and STU shall co-ordinate with the DISCOMs to determine voltage level at the inter-connection points. SLDC shall continuously monitor 400/220/132kV voltage levels at strategic sub-stations.

9.6.3 SLDC, in close coordination with NERLDC shall take appropriate measures to control State Transmission System voltages, which may include but not be limited to transformer tap changing, capacitor/ reactor switching including capacitor switching by DISCOMs at 33 kV sub-stations, operation of Hydro unit as synchronous condenser and use of MVAr reserves with the generators within its control area within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

9.6.4 SSGS and IPPs shall make available to SLDC, the up-to-date capability curves for all Generating Units, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to/ Import from State Transmission System. (Appendix-C)

9.6.5 DISCOMs and Open Access Users shall participate in voltage management by providing local VAR compensation (as far as possible in low voltage system close to load points) such that they do not depend upon EHV grid for reactive support.

9.6.6 Close Co-ordination between Users and SLDC, STU and NERLDC shall exist at all times for the purposes of effective frequency and voltage management.

**9.7 Reactive Power Management**

9.7.1 All Users shall endeavour to maintain the voltage at the inter-connection point in the range specified in the Grid Code.

9.7.2 All generating stations shall be capable of supplying reactive power support so as to maintain power factor at the point of inter-connection within the limits of 0.95

lagging to 0.95 leading as per the CEA Technical Standards for Connectivity Regulations and amendments thereof.

9.7.3 All generating stations connected to the grid shall generate or absorb reactive power as per instructions of SLDC, within the capability limits of the respective generating units, where capability limits shall be as specified by the OEM.

9.7.4 The reactive interchange of Users shall be measured and monitored by SLDC/ NERLDC.

9.7.5 SLDC/NERLDC may direct the Users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at inter-connection points.

9.7.6 SLDC shall assess the dynamic reactive power reserve available at various sub-stations or generating stations under any credible contingency on a regular basis based on technical details and data provided by Users, as per the procedure specified by SLDC (prepared in line with the procedure issued by NLDC or NERLDC).

9.7.7 SLDC shall take appropriate measures to maintain the voltage within limits, inter-alia, using the following facilities, but not limited to and the facility owner shall abide by the instructions of NLDC, RLDCs and SLDCs:

(i) Shunt reactors,

(ii) Shunt capacitors (excluding HVDC automatic control),

(iii) Thyristor-Controlled Series Capacitor (TCSC),

(iv) Voltage Sourced Converter (VSC) based High Voltage Direct Current (HVDC),

(v) Synchronous/non-synchronous generator voltage control including inverter based reactive power support,

(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.

9.7.8 Reactive power facility shall be in operation at all times and shall not be taken out without the permission of SLDC.

9.7.9 Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages, subject to technical feasibility, and wherever necessary, other options such as tap staggering may be carried out in the network.

9.7.10 Hydro and gas generating units having this capability shall operate in synchronous condenser mode operation as per instructions of the NERLDC or SLDC. Standalone synchronous condenser units shall operate as per the instructions of NERLDC or SLDC. The compensation for such synchronous condenser mode operation shall be included in the procedure, in line with the procedure of NERLDC/NLDC and approved by the Commission.

9.7.11 Any commercial settlement for reactive power shall be governed as per the regulatory framework specified in Appendix-K.

9.7.12 If voltage is outside the limit as specified in Regulation 9.6.1 of the Grid Code and the means of voltage control set out in Regulation 9.7.7 of the Grid Code are exhausted, SLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including switching ON or OFF of lines considering the security of the system.

# CHAPTER 10
# MONITORING OF GENERATION AND DRAWAL CODE

## 10 Monitoring of Generation and Drawal Code

### 10.1 Introduction

The monitoring of generating output and reserve capacity is important to evaluate the performance of generation plants.

The monitoring of scheduled drawal is important to ensure that STU, Transmission Licensees, DISCOMs and Open Access customers contribute towards improving system performance and observe grid discipline.

### 10.2 Objective

The objective of this chapter is to define the responsibilities of generating stations in monitoring of generating unit's reliability and performance, and STU's, DISCOMs'/Users' compliance with the scheduled drawal to assist SLDC in managing voltage and frequency.

### 10.3 Monitoring Procedure

10.3.1 SLDC shall continuously monitor generating unit outputs and bus voltages for effective operation of the State Transmission System and ensure that declared availability of generating stations are realistic.

10.3.2 SLDC can instruct a generating station to demonstrate its declared availability, in case SLDC has a reason to believe that declared availability of generating station does not match with actual availability or declared output does not match the actual output.

10.3.3 SLDC shall inform the generating stations, in writing, if continued monitoring demonstrates an apparent persistent or material mismatch between the despatch instructions and the generating unit output or breach of the Connection Conditions. Continued discrepancies shall be resolved in Grid Code Review Committee meeting with a view to either improve performance in future, providing more realistic declarations or initiate appropriate actions for any breach of Connectivity Conditions.

10.3.4 Generating stations shall provide to SLDC 15 minute time blockwise summation outputs whenever telemetry data is not available through SCADA/ RTU equipment. Generating stations/CPPs shall also provide any other logged readings that SLDC requires, for monitoring and reporting purposes.

### 10.4 Generating Unit Trippings

10.4.1 Generating stations shall immediately inform the tripping of a generating unit, with reasons, to SLDC in accordance with the operational event/ accident reporting Regulation. SLDC shall keep a written log of all such trippings, along with reasons, with a view demonstrating the effect on system performance and identifying the need for remedial measures.

10.4.2 The operating log books/ log records of the generating station and EHV sub-stations shall be available for review by SLDC. These books/ records shall keep record of machine operation, outage/ tripping of transmission elements and maintenance.

### 10.5 Monitoring of Drawal

10.5.1 SLDC shall continuously monitor actual MW drawal by DISCOMs and Open Access Customers against that scheduled by use of SCADA equipment. STU shall request NERLDC and adjacent States as appropriate to provide any additional data, if required to enable this monitoring to be carried out.

10.5.2 SLDC shall also monitor the actual MVAr drawal to the extent possible. This will be used to assist in voltage management of the State Transmission System.

### 10.6 Data Requirement

Users shall submit data to SLDC as listed in Data Registration Code, termed as Monitoring of Generation.

# CHAPTER 11
# OUTAGE PLANNING CODE

## 11 Outage Planning Code

### 11.1 Introduction

This chapter describes the process by which STU carries out the planning of State Transmission System Outages, including interface co-ordination with Users. Outage planning shall be done by SLDC for the grid elements in a coordinated and optimal manner, keeping in view the system operating conditions and grid security. The coordinated generation and transmission outage plan for the State grid shall take into consideration all the available generation resources, demand estimates, transmission constraints, and factor in water for irrigation requirements, if any. To optimize the transmission outages of the State grid, to avoid grid operation getting adversely affected and to maintain system security standards, the outage plan shall also take into account the generation outage schedule and the transmission outage schedule.

### 11.2 Objective

The objective of this chapter is to define the process, which will allow STU to optimise its transmission system outage, while maintaining the system security to the extent possible.

### 11.3 Annual Outage Planning and Process

11.3.1 Each User shall provide their operational planning data including outage programme as per Appendix-C or any other format as specified by SLDC, for ensuing financial year to SLDC for preparing an overall outage plan for State Transmission System, as a whole. SLDC shall be responsible for analysing the outage schedules submitted by the Generators, transmission outage plan submitted by the STU and compile the draft annual outage Plan for State Transmission System and submit to NERPC for preparation of yearly LGBR in line with the planning procedure formed by the NERPC. SLDC is authorised to defer the planned outage in case of any of the following events:

(a) Major grid disturbance;

(b) System Isolation;

(c) Black out in the State;

(d) Any other event in the system that may have an adverse impact on system security by the proposed outage.

11.3.2 Annual outage plan shall be prepared in advance for the financial year by SLDC in consultation with STU,DISCOMs and GENERATORs, as per their inputs and reviewed during the year on Bi-Monthly basis. Annual outage plan shall be prepared in such a manner as to minimize the overall downtime, particularly where multiple entities are involved in the outage of any grid elements. The outage planning of hydro generating stations, REGS and ESS and its associated evacuation network shall be planned with a view to extract maximum generating from these sources. Example: Outage of wind generator should be planned during lean wind season, whereas outage of solar, if required, should be planned during the rainy season, and outage of hydro power plant should be planned in the lean water season.

11.3.3 Protection relay related outages, auto–re-closure outages and SPS testing outages shall be planned on a monthly basis with the prior permission of the concerned RPC.

11.3.4 Generating stations connected to State grid shall furnish their proposed outage programme for the next financial year in writing by 15$^{th}$ September of each year. The outage programme shall contain details like identification of unit, reason for outage, generation availability affected due to such outage, outage start date and duration of outage.

11.3.5 STU shall submit to SLDC, the proposed outage programme for transmission lines, equipment and sub-stations, etc., for next financial year by 15th September each year. STU outage programmes shall contain identification of lines/ sub-stations, reason for outage, outage start date and duration of outage.

11.3.6 Scheduled outage of 400 kV transmission elements,220 kV/132 kV inter-State lines and all intra-state elements in the "List of important Grid Element of NER" published by NERLDC shall be effected only with the approval of NERPC/NERLDC in coordination with SLDC.

11.3.7 SLDC shall submit the proposed outage plan for the next financial year, taking all of the above into account, to the NERPC by 31$^{st}$ of October of each year.

11.3.8 The above annual outage plan shall be reviewed by SLDC on bi-monthly basis in State Operation and Co-Ordination Committee meeting in coordination with all parties concerned, to chalk out the outage of State transmission system and adjustments made wherever found to be necessary. The adjustments shall be communicated to NERPC, as and when carried out.

Further, if any deviation is required by the users, STUs and licensees for an element of the state grid, from the annual outage plan issued by NERPC, the same shall be done only with the prior permission of the concerned RPC through the SLDC.

11.3.9 SLDC shall submit Load Generation Balance Report (LGBR) for its control area to NERPC Secretariat in writing for the next financial year by 31st October of each year. These shall contain identification of each generating unit/ transmission line/ ICT, etc., the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date. The annual plans for managing deficits/ surplus in respective control areas shall clearly be indicated in the LGBR submitted by SLDC.

11.3.10 The NERPC Secretariat shall be primarily responsible for finalization of LGBR and the annual outage plan for the following financial year by 31st December of each year.

### 11.4 Schedule for availing of shutdowns

11.4.1 SLDC would review on daily basis the outage schedule for the next two days and in case of any contingency, defer any planned outage as deemed fit, clearly stating the reasons thereof. The revised dates in such cases would be finalized in consultation with User.

11.4.2 Each User and STU shall obtain the final approval from SLDC prior to availing an outage.

# CHAPTER 12
# CONTINGENCY PLANNING CODE

## 12 Contingency Planning Code

### 12.1 Introduction

This chapter describes the steps in the recovery process to be followed by all Users in the event of total or partial blackouts of the State Transmission System or Regional System.

### 12.2 Objective

The objective of this chapter is to define the responsibilities of all Users to achieve the fastest recovery in the event of blackout of State Transmission System or Regional System, taking into account essential loads, Generator capabilities and system constraints.

### 12.3 Contingency Planning Procedure

12.3.1 SLDC, in coordination with NERLDC, shall prepare contingency plan to efficiently handle the following two types of contingencies:

(a) Partial system black out in the State due to multiple tripping of the transmission lines emanating from power stations/sub-station; and

(b) Total black out in the State/region.

12.3.2 In case of partial black out in the system/State, priority should be given for early restoration of power station units, which are tripped. Start-up power for the power station shall be extended through shortest possible line and within shortest possible time from adjoining sub-station/ power station where the supply is available. Synchronising facility at all power stations and 400/ 220 kV sub-station shall be available.

12.3.3 In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of NERLDC for early restoration of the entire grid. After total collapse, for each power station, to avoid damage to the turbine, survival power is required. To meet the survival power, the diesel generating (DG) sets of sufficient capacity shall be available at each power station. Start-up power to the thermal station shall be given by the hydel stations and inter-State supply, if available. All possible efforts shall be made to extend the hydel supply to the thermal power stations through shortest transmission network to avoid high voltage problem due to low load condition. For safe and fast restoration of supply, STU shall formulate the proper sequence of operation for major generating units, intra-State transmission lines, transformers and load within the State in consultation with NERPC. The sequence of operation shall include closing/ tripping of circuit breakers, isolators, on-load tap-changers, etc. In emergency situations, the Distribution Licensee may approach a nearby captive power plant to get the extremely important energy requirement at the earliest. The STU shall formulate the proper sequence of operations in this regard.

**12.4 Restoration Procedure**

12.4.1 SLDC shall prepare detailed procedure for restoration for the control area of the State grid, in line with the procedure developed by the NERLDC, and in consultation with STU and users, which shall be updated every year by taking into account changes in the configuration of the power system. The restoration process shall take into account the generator capabilities and the operational constraints of State Transmission System with the object of achieving normalcy in the shortest possible time. All Users must be aware of the steps to be taken during major grid disturbance and system restoration process. These steps shall be followed by all the Users to ensure consistent, reliable and quick restoration.

12.4.2 Detailed procedures for restoration post partial and total blackout of each User system within the State shall be prepared by the concerned User in coordination with SLDC. The concerned User shall review the procedure every year and update the same. The User shall carry out a 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 and Voltage Source Converters (VSC) based HVDC black-start support at least once a year under intimation to SLDC / NERLDC. Diesel generator sets and other standalone auxiliary supply source to be used for black start shall be tested on a weekly basis and the User shall send the test reports to the SLDC, NERLDC on a quarterly basis.

12.4.3 Simulation studies shall be carried out by each User in coordination with SLDC / NERLDC for preparing, reviewing and updating the restoration procedures considering the following:

(a) Black start capability of the generator;

(b) Ability of black start generator to build cranking path and sustain island;

(c) Impact of block load switching in or out;

(d) Line/ transformer charging;

(e) Reduced fault levels; and

(f) Protection settings under restoration condition.

12.4.4 The thermal and nuclear generating stations shall prepare themselves for house load operation as per design. The concerned User and SLDC shall report the performance of house load operation of a generating station in the event where such operation was required.

12.4.5 SLDC shall identify the generating stations with black start facility, grid forming capability of inverter based generating stations, house load operation facility, inter-State or inter-regional ties, synchronizing points and essential loads to be restored on priority.

12.4.6 During the restoration process following a blackout, SLDC is authorized to operate with reduced security standards for voltage and frequency and may direct the implementation of any such operational setting as necessary, in order to achieve the fastest possible recovery of the grid.

12.4.7 Any entity extending black start support by way of injection of power as identified in Regulation 12.4.5 of the Grid Code shall be paid for actual injection @ 110 % of the normal rate of charges for deviation in accordance with Assam Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 , as applicable for the last block in which the grid was available. The procedure in this regard shall be prepared by SLDC in consultation with stakeholders and approved by the Commission.

**12.5 Real Time Operation**

12.5.1 **System state**

Power system shall be categorized under normal, alert, emergency, extreme emergency and restoration state depending on the type of contingencies and value of operational parameters of the power system by RLDC, NLDC or SLDC, as the case may be.

**(a) Normal state**

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. Under normal state, the power system is secure and capable of maintaining stability under contingencies defined in the CEA Transmission Planning Criteria and updated thereof.

**(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 ('N-1') leads to a violation of security criteria. The power system remains intact under such alert state. However, whenever the power system is under alert state, the system operator shall take corrective measures to bring it back to a normal state.

**(c) Emergency state**

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. Emergency state can arise out of multiple contingencies or any major grid disturbance in the system. The power system remains intact under such emergency state. However, whenever the power system is under emergency sate, it is the responsibility of the system operator to bring back the power system to alert/normal and shall take corrective measures such as:

- extreme measures such as load shedding, generation unit tripping, line tripping or closing,
- emergency control action such as HVDC Control, Excitation Control, HP-LP Bypass, tie line flow rescheduling on critical lines, and
- automated action such as system protection scheme, load curtailment scheme and generation run-back scheme.

**(d) Extreme emergency state**

Power system shall be categorized under extreme emergency state if the control actions taken during the emergency state are not able to bring the system either to an alert state or a normal state and operational parameters are outside their respective operational limits or equipment are critically loaded. Extreme emergency state may arise due to high impact low frequency events like natural disasters. The power system may or may not remain intact (splitting may occur) and extreme events like generation plant tripping, bulk load shedding, under frequency load shedding (UFLS) and under voltage load shedding (UVLS) operation may occur.

**(e) Restorative state**

Power system shall be categorized under restorative state when control action is being taken to reconnect the system elements and restore system load. The power system transits from a restorative state to either an alert state or a normal state, depending on the system conditions.

12.5.2 SLDC shall maintain the grid in the normal state by taking suitable measures. In case, the power system moves away from the normal state, appropriate measures shall be taken to bring the system back to the normal state. In case the power system has moved to an extreme emergency state, SLDC shall take emergency action and initiate restorative measures immediately.

12.5.3 Procedure to be followed during an event:

(a) In case of an event on the intra-State transmission system that may significantly impact the inter-State transmission system, SLDC shall immediately inform the concerned RLDC;

(b) any warning in respect of system security issued by NLDC/ RLDC/ SLDC, shall be taken note of immediately by the concerned Users who shall take the necessary action to withstand the said event or to minimize its effect.

12.5.4 Operational coordination:

(a) For operational coordination, each intra-State Transmission Licensee, generating station and QCA shall have a control centre or coordination centre for round the clock coordination.

(b) Any planned operation activity in the Intra-State Transmission system [such as generating unit synchronization or de-synchronization, transmission element opening or closing (including breakers), protection system outage, System Protection Schemes (SPS) outage and testing, etc.] shall be done by taking operational code from SLDC. The operational code shall have validity period of sixty (60) 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 SLDC.

(c) In case of forced outages/ breakdowns, the element should be brought back to service only after obtaining Operational code from SLDC.

### 12.6 Special Considerations

12.6.1 During the restoration process, normal standards of voltage and frequency shall not apply.

12.6.2 Distribution Licensees with essential loads will separately identify non-essential components of such loads, which may be kept off during system contingencies and submit the same to SLDC. Distribution Licensees shall draw up an appropriate schedule with corresponding load blocks in each case. The non-essential loads can be put on only when system normally is restored, as advised by SLDC.

12.6.3 All Users shall pay special attention in carrying out the procedures so that secondary collapse due to undue haste or inappropriate loading is avoided.

12.6.4 Despite the urgency of the situation, careful prompt and complete logging of all operations and operational messages shall be ensured by all Users to facilitate subsequent investigation into the incident and the efficiency of the restoration process. Such investigation shall be conducted promptly after the incident.

12.6.5 All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

# CHAPTER 13
# CROSS BOUNDARY SAFETY CODE

## 13 Cross Boundary Safety Code

### 13.1 Introduction

This chapter sets down the requirements for maintaining safe working practices associated with cross boundary operations. It lays down the procedure to be followed when work is required to be carried out on electrical equipment that is connected to another User's system.

### 13.2 Objective

The objective of this chapter is to achieve agreement and consistency on the principles of safety as specified in the Indian Electricity Rules when working across an cross boundary between one User and another User.

### 13.3 Designated Officers

STU and all Users shall nominate authorized persons responsible for the co-ordination of safety across the Company boundary. These persons shall be referred as Designated Officer.

### 13.4 General

13.4.1 All users shall comply with the agreed safety rules drawn up in accordance with central electricity authority (measures relating to safety and electric supply) regulation, 2010.

13.4.2 All the equipment on cross boundary circuits, which may be used for the purpose of safety coordination and establishment of isolation and earthing, shall be permanently and clearly marked with an identification number or name being unique to the particular substation. The equipment shall be regularly inspected and maintained in accordance with the manufacturer's specification.

13.4.3 Each of the distribution licensees connected to the transmission system shall maintain an updated map of his system pertaining to the area fed by each substation, and exhibit the same in the concerned area offices of the distribution licensee.

### 13.5 Procedure for Cross Boundary Safety

13.5.1 STU/ Transmission Licensee shall issue a list of control persons with their names, designations, addresses and telephone numbers to all the users having direct control boundary with it. This list shall be updated promptly whenever there is any change of name, designation or telephone number of any control person named in the list.

13.5.2 Whenever any work across a cross boundary is to be carried out by the user or STU/Transmission Licensee as the case may be, who has to carry out the work, shall directly contact his counterpart. Code words shall be agreed to, at the time of work, to ensure correct identification of both the parties. Contact between control persons shall normally be made by direct telephone.

13.5.3 If the work extends beyond one shift, the control person shall hand over charge to the relief control person and fully brief him on the nature of work and the code words in the operation.

13.5.4 The control persons shall co-operate to establish and maintain the precautions necessary to be taken for carrying out the required work in a safe manner. Both the established isolation and the established earth shall be kept in the locked positions wherever such facilities exist, and these shall be clearly identified and entered into the log sheet.

13.5.5 The control person in charge of the work shall satisfy himself that all the safety precautions to be taken are established before commencing the work. He should issue the safety documentation to the working party to allow the work to commence.

13.5.6 After completion of the work, the control person in charge of the work being carried out, should satisfy himself that the safety precautions taken are no longer required, and shall make a direct contact with his counterpart control person and request removal of the safety precautions. The equipment shall be declared as suitable for return to service only after confirmation of removal of all the safety precautions by direct communication, using the code word contact between the two control persons, and the return of agreed safety documentation from the working party.

13.5.7 STU shall develop an agreed written procedure for cross boundary safety and continuously update the same.

13.5.8 Any dispute concerning cross boundary safety shall be resolved at the level of STU, if STU is not a party. In case where STU is a party, the dispute shall be referred to the Commission for resolution.

# CHAPTER 14
# REPORTS

## 14 Reports

## 14.1 Periodic reports

### 14.1.1 Monthly Report

Daily and monthly inputs shall be provided to the NERLDC by the SLDC and users, as specified the NERLDC. A monthly report shall be uploaded by SLDC on its website, which shall cover the performance of the State grid for the previous month. The monthly report shall contain the following:

(a) Frequency profile.

(b) Source wise generation for the control area

(c) Drawal from the grid and area control error

(d) Demand met (peak, off-peak and average)

(e) Demand and energy unserved in MW and MWh

(f) Instances and quantum of curtailment of renewable energy

(g) Maximum and minimum frequency recorded daily and daily frequency variation index (FVI).

(h) Voltage profile.

(i) Voltage profile of selected sub-stations.

(j) Major Generation and Transmission Outages.

(k) Transmission Constraints and instances of congestion in the transmission system.

(l) Instances of persistent / significant non-compliance of Grid Code.

(m)Grid Security events, leading to curtailment along with reasons.

### 14.1.2 Other Reports/ Forms

The SLDC shall also upload a quarterly report on its website, which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of various actions taken by different Users and the Users responsible for causing the constraints.

14.1.3 These reports shall also be submitted to the Commission within a week from the date of issue of the reports.

## 14.2 Operational Event/ Accident Reporting

### 14.2.1 Introduction

This chapter describes the reporting procedure, of reportable events in writing in the State Transmission System.

### 14.2.2 Objective

The objective of this chapter is to define the incidents to be reported, the reporting route to be followed and the information to be supplied to ensure a consistent approach for reporting of incidents and accidents on the Intra-State Transmission System.

### 14.2.3 Reportable Incidents

Any of the following events that could affect the State Transmission System requires reporting:

(a) Exceptionally high / low system voltage or frequency.

(b) Serious equipment problem, i.e., major circuit breaker, transformer or bus-bar etc.

(c) Loss of Generating Unit.

(d) Instance of Black Start.

(e) Tripping of Transmission Line, Interconnecting transformer (ICT) and capacitor banks

(f) Major fire incidents.

(g) Major failure of protection.

(h) Equipment and transmission line overload.

(i) Accidents - Fatal and Non-Fatal.

(j) Load Crash / Loss of Load.

(k) Violation of Security Standards.

(l) Grid indiscipline.

(m) Non-compliance of SLDC instructions.

(n) Excessive drawal deviations.

(o) Minor equipment alarms.

The last two reportable incidents are typical examples of those, which are of lesser consequence, but still affect the State Transmission System and can be reasonably classed as minor. They will require corrective action but may not warrant management reporting until these are repeated for sufficient time.

14.2.4 **Reporting Procedure/ Forms**

(a) All reportable incidents occurring in lines and equipment affecting the State Transmission System shall promptly be communicated by the User whose equipment has experienced the incident (the Reporting User) to any other significantly affected Users and to SLDC.

(b) Within one (1) hour of being informed by the Reporting User, SLDC may ask for a written report on any incident as per Appendix-H.

(c) If case of minor incident, the Reporting User shall submit an initial written report within two (2) hours and comprehensive report within twenty-four (24) hours of the submission of the initial written report, whereas, in other cases, the Reporting User shall submit a report within five (5) working days to SLDC.

(d) SLDC may call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been source of the reportable incident. This shall not relieve any User from the obligation to report events in accordance with IE Rules.

(e) The format of such a report will be as agreed by the Grid Code Management Committee, but will typically contain the following information:

i) Location of incident.

ii) Date and time of incident.

iii) Plant or equipment involved.

iv) Details of relay indications with nature of fault implications.

v) Supplies interrupted and duration if applicable.

vi) Amount of generation lost if applicable.

vii) Brief description of incident.

viii) Estimate of time to return to service.

ix) Name of originator.

x) Possibility of alternate arrangement of supply

xi) Single line diagram

xii) All Relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, Data Acquisition System (DAS), etc.

14.2.5 **Major Failure**

Following a major failure, SLDC and other Users shall co-operate to inquire and establish the cause of such failure and produce appropriate recommendations. The SLDC shall report the major failure to the Commission immediately for information and shall submit the enquiry report to the Commission within two (2) months of the incident.

14.2.6 **Accident Reporting**

Reporting of accidents shall be in accordance with the relevant Rules/ Regulations/ Grid Code. In both fatal and non-fatal accidents, the report shall be sent to the Electrical Inspector in the specified form.

# PART IV
# CHAPTER 15
# PROTECTION CODE

## 15 Protection Code

### 15.1 Introduction

15.1.1 The chapter covers the protection protocol, protection settings and protection audit plan of electrical systems to be adopted in order to safeguard the State Transmission System and User's system from faults.

### 15.2 Objective

15.2.1 The objective of this chapter is to define the minimum protection requirements for any equipment connected to the State Transmission System and thereby minimize the disruption due to faults.

### 15.3 General Principles

15.3.1 There should be a uniform protection protocol for the Users of the State 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;

(b) to have a repository of protection system, settings and events at State level;

(c) specifying timelines for submission of data;

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

(e) to provide for periodic audit of protection system.

15.3.2 STU shall be guided by the advice of NERPC / NERLDC for the following:

(i) Planning for upgrading and strengthening protection system based on analysis of grid disturbance and partial/total blackout in State Transmission System.

(ii) Planning of Islanding and system split schemes and installation of Under Frequency Relays and df/dt relays.

15.3.3 Under-Frequency relay for load shedding, relays provided for islanding scheme, disturbance recorder, and fault locator installed at various sub-stations shall be tested and calibrated. All Users shall ensure correct and appropriate settings of protection equipment.

15.3.4 Protection settings shall not be altered or protection bypassed and/or disconnected without consultation and agreement of all affected Users. In the case where protection is bypassed and/or disconnected, by agreement, then the cause must be rectified, and the protection restored to normal condition as quickly as possible. If agreement has not been reached, the electrical equipment will be removed from service forthwith.

15.3.5 No item of electrical equipment shall be allowed to remain connected to the State Transmission System unless it is covered by minimum specified protection aimed at reliability, selectivity, speed and sensitivity.

**15.4 Protection Co-ordination**

A State Protection Coordination Committee (SPCC) shall be constituted as in Clause 3.4**Error! Reference source not found.** of the Grid Code and shall be responsible for all the protection coordination functions. STU shall be responsible for arranging periodical meetings of the SPCC. STU shall investigate any malfunction of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection mal-function or issue as discussed and agreed to, in the periodical meetings. The functioning of the SPCC shall be governed in line with that of the concerned body of the NERPC.

**15.5 Protection Protocol**

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

15.5.2 Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.

15.5.3 SPCC shall develop the protection protocol, in reference with that of the NERPC, and revise the same, after review from time to time, in consultation with the stakeholders in the State, 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 CEA Technical Standards for Connectivity Regulations, CEA Grid Standards

Regulations, CEA Technical Standards for Communication Regulations, CEA Technical Standards for Construction Regulations, CEA Safety Regulations and amendments thereof and any other CEA standards specified from time to time.

15.5.4 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 State Protection Coordination Committee (SPCC) and approval of NERPC, wherever applicable.

15.5.5 Violation of the protection protocol of the State shall be brought to the notice of SPCC by SLDC.

**15.6 Protection Settings**

15.6.1 SPCC 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 State from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the SPCC. The data including base case (peak and off-peak cases) files for carrying out studies shall be provided by SLDC and STU to SPCC.

15.6.2 All Users connected to the grid shall:

(a) furnish the protection settings implemented for each element to SPCC in a format to be prescribed by SPCC;

(b) obtain approval of SPCC for any revision in settings and implementation of new protection system;

(c) intimate to SPCC 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 SPCC; and

(e) ensure proper coordinated protection settings.

15.6.3 State Protection Coordination Committee (SPCC) shall:

(a) maintain a centralized database and update the same on periodic basis in respect of the State containing details of relay settings for grid elements connected to 132 kV and above. SLDC shall also maintain such database.

(b) carry out detailed system studies once in a year, for protection settings and advice modifications / changes, if any, to STU and all Users. The data required to carry out such studies shall be provided by SLDC, STU and Users, as the case may be.

(c) provide the database access to STU and SLDC and to all Users of the State. The database shall have different access rights for different Users.

15.6.4 The changes in the network and protection settings of grid elements connected to the State Grid shall be informed to State Protection Coordination Committee (SPCC),SLDC and NERPC (wherever applicable) by the STU and DCC., as the case may be.

**15.7 Protection Audit Plans**

15.7.1 All Users shall conduct internal audit of their protection systems annually and any shortcomings identified shall be rectified and informed to SPCC and SLDC. The audit report along with action plan for rectification of deficiencies detected if any, shall be shared with SPCC and SLDC.

15.7.2 All users shall also conduct third party protection audit of each sub-station at 132 kV and above once in five years or earlier as advised by the NERPC and SPCC shall supervise the same. For substations below 132kV connected to the State Grid, the third part audit shall be as per the methodology devised by the SPCC.

15.7.3 The list of sub-stations/ generating stations identified by NERPC, in line with Clause 15.7.2, where third-party protection audit is required to be carried out, SPCC shall ensure completion of the third-party audit within three months. Further, for all elements of the State Grid SPCC shall identify a list of sub-stations/ generating stations where third-party protection audit is required to be carried out and accordingly advise the respective Users to complete third-party audit within three months.

15.7.4 The third-party protection audit report shall contain information sought in the format enclosed as Appendix–J. The protection audit reports along with action plan for rectification of deficiencies detected, if any, shall be submitted to NERLDC/NERPC (wherever applicable), SPCC and SLDC within a month of submission of third-party audit report. The necessary compliance to such protection audit report and NERLDC/NERPC directions shall be followed up regularly in SPCC meetings.

15.7.5 Annual audit plan for the next financial year shall be submitted by the Users to NERLDC/NERPC (wherever applicable), SPCC and SLDC by 31st October. The Users shall adhere to the annual audit plan and report compliance of the same to SPCC and to SLDC for record purposes.

15.7.6 Users shall submit the following protection performance indices of previous month to NERPC (for 132 kV and above system), SPCC and SLDC on monthly basis, which shall be reviewed by the SPCC:

The Dependability Index defined as $D = N_c / (N_c+N_f)$;

The Security Index defined as $S = N_c/(N_c+N_u)$; and

The Reliability Index defined as $R = N_c / (N_c+N_i)$;

where,

$N_c$ is the number of correct operations at internal power system faults;

$N_f$ is the number of failures to operate at internal power system faults;

$N_u$ is the number of unwanted operations; and

$N_i$ is the number of incorrect operations and is the sum of $N_f$ and $N_u$.

15.7.7 Each User shall also submit the reasons for performance indices less than unity of individual element-wise protection system to NERPC (for 132 kV and above system), SPCC, SLDC and action plan for corrective measures. The action plan will be followed up regularly by the SPCC.

15.7.8 In case any User fails to comply with the protection protocol specified by SPCC or fails to undertake remedial action identified by the NERPC/SPCC within the specified timelines, SPCC / SLDC/ STU may approach the Commission with all relevant details for suitable directions.

**15.8 System Protection Scheme** (SPS)

15.8.1 System Protection Scheme (SPS) for identified system shall have redundancies in measurement of input signals and communication paths involved up to the last mile to ensure security and dependability.

15.8.2 For the operational System Protection Scheme (SPS) for the State Grid, SLDC in consultation with SPCC and with reference to the SPS designed by NERPC/NERLDC shall perform regular load flow and dynamic studies and mock testing for reviewing System Protection Scheme parameters and functions, at least once in a year. SLDC shall share the report of such studies and mock testing including any short comings to SPCC. The data for such studies shall be provided by STU / Discoms/Generators to the SLDC/SPCC.

15.8.3 The Users and SLDC shall report about the operation of System Protection Scheme (SPS) immediately and detailed report shall be submitted within three days of operation to SPCC and NERPC/NERLDC(wherever applicable) in the specified format.

15.8.4 The performance of System Protection Scheme (SPS) shall be assessed as per the protection performance indices specified in this Grid Code. In case, the System Protection Scheme (SPS) fails to operate, the concerned User shall take corrective actions and submit a detailed report on the corrective actions taken to SPCC and NERPC (wherever applicable) within a fortnight.

**15.9 Recording Instruments**

15.9.1 All Users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.

15.9.2 The disturbance recorders shall have time synchronization and a standard format for recording analog and digital signals, which shall be included in the guidelines issued by SPCC.

15.9.3 The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers by SLDC. Disturbance recorders, which are non-compliant shall be listed out for discussion at SPCC meeting and NERPC PCC meeting, wherever applicable.

**15.10Calibration and Testing**

15.10.1 The protection scheme shall be tested at each 400 kV, 220 kV, 132kV and 66kV sub-station by STU once in a year or immediately after any major fault, whichever is earlier. Setting, co-ordination, testing and calibration of all protection schemes pertaining to generating units/stations shall be the responsibility of respective Generator.

15.10.2 The periodic testing shall be carried out on power system elements for ascertaining the correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system.

15.10.3 The owner of the power system element shall be responsible for carrying out tests as specified in these regulations and for submitting reports to STUs and SLDCs for intra-State elements.

15.10.4 All equipment owners shall submit a testing plan for the next year to the STU/SLDC/NERPC 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 STU/SLDC/NERPC in advance.

15.10.5 The tests shall be performed once every five (5) years or whenever major retrofitting is done. 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 NERPC, as the case may be.

15.10.6 The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports in consultation with STU, SLDC, NERPC, NLDC, NERLDC, CEA and CTU.

15.10.7 The overall co-ordination between Users and STU shall be decided in the meeting of SPCC. The SPCC shall review the testing and calibration as and when needed.

15.10.8 **The following tests shall be carried out on the respective power system elements:**

| **Power System Elements** | **Tests** | **Applicability** |
|---|---|---|
| Synchronous Generator | (1) Real and Reactive Power Capability assessment.<br>(2) Assessment of Reactive Power Control Capability as per CEA Technical Standards for Connectivity Regulations<br>(3) Model Validation and verification test for the complete Generator and Excitation System model including PSS.<br>(4) Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions.<br>(5) Testing of Governor performance and Automatic Generation Control. | Individual Unit of rating 100 MW and above for Coal/lignite, 50 MW and above gas turbine and 25 MW and above for Hydro. |

| | | |
|---|---|---|
| Non synchronous Generator (Solar/Wind) | (1) Real and Reactive Power Capability for Generator<br>(2) Power Plant Controller Function Test<br>(3) Frequency Response Test<br>(4) Active Power Set Point change test.<br>(5) Reactive Power (Voltage / Power Factor / Q) Set Point change test | Applicable as per CEA Technical Standards for Connectivity Regulations. |
| HVDC/FACTS Devices | (1) Reactive Power Controller (RPC) Capability for HVDC/FACTS<br>(2) Filter bank adequacy assessment based on present grid condition, in consultation with NLDC.<br>(3) Validation of response by FACTS devices as per settings. | To all ISTS HVDC as well as Intra-State HVDC/FACTS, as applicable |

**15.11 Capacity Building and Certification**

Capacity building, skill upgradation, and certification of the personnel deployed in Generating Stations, Load Despatch Centres and EHV Sub-stations shall be done periodically under an institutional framework through accredited certifying agency(ies).

**15.12 Data Requirements**

Users shall provide STU with data for this chapter as specified in Appendix D of Data Registration Code.

**15.13 Inspection of Records:**

The operational logs and records of the generating stations and transmission licensees connected to the State Transmission System shall be available for inspection and review by the SLDC.

# PART V
# CHAPTER 16
# TRANSMISSION METERING CODE

## 16 Transmission Metering Code

16.1.1 The STU or Discom, as the case may be, shall be responsible for procurement and installation of Interface Energy Meters (IEMs), at the cost of respective entity, at all the interface points and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points, and its operation and periodic calibration shall be done by the respective entity.

16.1.2 STU or Discom, as the case may be, shall be responsible for replacement of faulty meters.

16.1.3 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 and its amendments thereof

16.1.4 The installation, operation, and maintenance of additional communication links, if any, required for the purpose of AMR facility shall be in accordance with CEA Communications Regulations and its amendments thereof.

16.1.5 Access to such metering data to the NERLDC / SLDC shall be in accordance with the CEA Metering Regulations 2006 and its amendments thereof.

16.1.6 Entities in whose premises the IEMs are installed shall be responsible for

(a) monitoring the healthiness of the CT and PT inputs to the meters,

(b) taking weekly meter readings for the seven day period ending on the preceding Sunday 2400 hrs and transmitting them to the SLDC by Tuesday noon, in case such readings have not been transmitted through automatic remote meter reading (AMR) facility

(c) monitoring and ensuring that the time drift of IEM is within the limits as specified in CEA Metering Regulations 2006 and

(d) promptly intimating the changes in CT and PT ratio to RLDC

16.1.7 SLDC shall, based on the IEM readings, compute time block wise actual net injection and drawal of the state entities within their control area:

Provided that the computations done by SLDC shall be open to all concerned entities for a period of fifteen (15) days for checking and verification.

16.1.8 In case any error or omission is detected by self-analysis or brought to notice by an entity, the SLDC shall make a complete check and rectify the error within a period of a month from date of such detection.

16.1.9 SLDC shall compile and forward the IEM readings and the implemented schedule to the NERLDC/NERPC on a weekly basis by each Thursday for the preceding seven days period ending on the preceding Sunday mid-night, as applicable. This is to enable the NERLDC/NERPC/SLDC, as the case may be, 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 Appendix-M of these regulations.

# CHAPTER 18
# CYBER SECURITY CODE

## 17 Cyber Security Code

### 17.1 General

(i) This chapter deals with measures to be taken to safeguard the State grid from spyware, malware, cyber-attacks, network hacking, procedure for security audit from time to time, upgradation of system requirements and keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements.

(ii) All Users, SLDC and STU shall have in place, a Cyber Security framework in accordance with Information Technology Act, 2000, CEA Technical Standards for Connectivity Regulations, CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such Regulations issued from time to time, by an appropriate authority to identify the critical cyber assets and protect them so as to support reliable operation of the grid.

### 17.2 Cyber Security Audit

All Users, SLDC and STU, 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.

A Cyber Security Committee (CSC) shall be constituted under STU and DISCOM to oversee and ensure compliance by the users connected with the respective licensee as per the provisions in these regulations. SLDC in consultation with STU and DISCOM shall formulate and submit, the working modalities of the Committee, for approval of the Commission.

### 17.3 Mechanism of Reporting

(i) 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 and the CSC, in case of any cyber- attack.

(ii) SLDC and the Commission shall also be informed by such entities in case of any instance of cyber-attack.

### 17.4 Cyber Security Coordination

(i) The CSC shall be responsible for ensuring co-ordination with 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 the regional sub-committee, as the case may be.

# PART VI
# DATA REGISTRATION CODE & MISCELLANEOUS
# CHAPTER 18
# DATA REGISTRATION CODE

## 18 Data Registration Code

### 18.1 Introduction

This chapter contains list of data required by STU and SLDC, which is to be provided by Users and data required by Users to be provided by STU at times specified in the Grid Code. Other chapters of the Grid Code contain the obligation to submit the data and defines the times, when such data is to be provided by Users.

### 18.2 Objective

The objective of this chapter is to list all the data required to be provided by Users to STU and vice versa, in accordance with the provisions of the Grid Code.

### 18.3 Responsibility

(i) All Users are responsible for submitting up-to-date data to STU / SLDC in accordance with the provisions of the Grid Code.

(ii) All Users shall provide STU and SLDC with the name, address and telephone number of the person responsible for sending data.

(iii)STU shall inform all Users and SLDC, the name, address and telephone number of the person responsible for receiving data.

(iv) STU shall provide up-to-date data to Users as provided in the relevant schedule of the Grid Code.

(v) Responsibility for the correctness of data rests with the concerned User providing the data.

### 18.4 Data Categories and Stages in Registration

Data required to be exchanged has been listed in the appendices of this chapter under various categories with cross-reference to the concerned chapters.

### 18.5 Changes to User's Data

Whenever there is any change/modification in the data submitted by User that is registered with STU, the User must promptly notify STU of such changes. STU on receipt of intimation of the changes shall promptly correct the database accordingly. This shall also apply to any data compiled by STU regarding to its own system.

**18.6 Methods of submitting Data**

(i) The data shall be furnished to SLDC/STU in the standard formats. However, in cases where standard formats are not enclosed, the same would be developed by SLDC/ STU in consultation with Users and made a part of the Detailed Procedure.

(ii) Where a computer data link exists between a User and SLDC/ STU, data may be submitted via link. Other modes of data transfer, such as pen drive may be utilised, if SLDC/ STU gives its prior written consent.

**18.7 Special Considerations**

(i) STU and SLDC and any other User may at any time make reasonable request for extra data as necessary.

(ii) STU shall supply data, required/requested by SLDC for system operation, from data bank to SLDC.

# CHAPTER 19
# MISCELLANEOUS

## 19 Miscellaneous

### 19.1 Detailed Procedures

SLDC, after due consultation with the stakeholders, shall prepare the detailed procedures, entrusted under various chapters of this grid code and submit the same the Commission within 3 (three) months from the date of issue of the gazette notification for this regulation.

Also, all the standard formats, arrangements, architecture, etc. for functioning of the grid and proper implementation of this grid code shall be made a part of the detailed procedures. The Appendices provided in this code shall be used for reference.

### 19.2 Power to Relax

The Commission for reasons to be recorded in writing, may relax any of the provisions of the Grid Code on its own motion or on an application made before it by an interested person.

### 19.3 Power to Remove Difficulty

If any difficulty arises in giving effect to the provisions of this Grid Code, the Commission may, by order, make such provisions not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of the Grid Code.

### 19.4 Repeal and Savings

(a) The Grid Code namely "Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2018 notified on 5th September 2018 and read with all amendments thereto, is hereby repealed.

(b) Nothing in this Grid Code shall be deemed to limit or otherwise affect the inherent powers of the Commission to make such orders as may be necessary for ends of justice to meet or to prevent abuses of the process of the Commission.

(c) Nothing in this Grid Code shall bar the Commission from adopting, in conformity with the provisions of the Act, a procedure which is at variance with any of the provisions of this Grid Code, if the Commission, in view of the special circumstances of a matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

(d) Nothing in this Grid Code shall, expressly or impliedly, bar the Commission dealing with any matter or exercising any power under the Act for which no Regulations have been framed and the Commission may deal with such matters, power and functions in a manner it thinks fit.

**19.5 Issue of Suo-moto Orders and Directions**

The Commission may from time-to-time issue suo-moto orders and practice directions with regard to implementation of this Grid Code and matters incidental or ancillary thereto, as the case may be.

**19.6 Treatment of this Grid Code in Contract**

The provisions of this Grid Code or any amendments thereof shall not be treated under 'Change in law' in any of the agreements entered into by any of the Users covered under this Grid Code.

**By Order of the Commission**

**Secretary**

# APPENDIX

**APPENDIX A: STANDARD PLANNING DATA**

Standard Planning Data consist of details, which are expected to be normally sufficient for STU to investigate the impact on the State Transmission System due to User development. Standard planning data covering (a) preliminary project planning

**REFERENCE TO:**

**CHAPTER - 4 RESOURCE ADEQUACY AND SYSTEM PLANNING CODE**

**CHAPTER - 5 CONNECTION CODE**

**A-1 STANDARD PLANNING DATA (GENERATION)**

For **SSGS** – Thermal

**A.1.1 THERMAL (COAL / GAS/FUEL LINKED)**

**A.1.1.1 GENERAL**

| | | |
|---|---|---|
| i | Site | Give location map to scale showing roads, railway lines,<br>Transmission lines, canals, pondage and reservoirs if any. |
| ii | Coal linkage/ Fuel (Like Liquefied Natural Gas, Naphtha etc.) linkage | Give information on means of coal transport / carriage. In case of other fuels, give details of source of fuel and their transport. |
| iii | Water Sources | Give information on availability of water for operation of the Power Station. |
| iv | Environmental | State whether forest or other land areas are affected. |
| v | Site Map (To Scale) | Showing area required for Power Station coal linkage, coal yard, water pipe lines, ash disposal area, colony etc. |
| vi | Approximate period of construction | |

**A.1.1.2 CONNECTION**

| | | |
|---|---|---|
| i | Point of Connection | Give single line diagram of the proposed Connection with the system. |
| ii | Step up voltage for Connection (kV) | |

**A.1.1.3 STATION CAPACITY**

| | | |
|---|---|---|
| i | Total Power Station capacity (MW) | State whether development shall be carried out in phases and if so, furnish details. |
| ii | No. of units & unit size (MW) | |

**A.1.1.4 GENERATING UNIT DATA**

| | | |
|---|---|---|
| i | Steam **Generating Unit** | State type, capacity, steam pressure, steam temperature etc. |
| ii | Steam turbine | State type, capacity |

| | | |
|---|---|---|
| iii | Generator | Type<br>Rating (MVA)<br>Speed (RPM)<br>Terminal voltage (kV)<br>Rated Power Factor<br>Reactive Power Capability<br>( MVAr) in the range 0.95 of leading and 0.85 lagging<br>Short Circuit Ratio<br>Direct axis (saturated) transient reactance (% on MVA rating)<br>Direct axis (saturated) sub-transient reactance ( % on MVA rating)<br>Auxiliary Power Requirement<br>MW and MVAr Capability curve |
| iv | Generator Transformer | Type<br>Rated capacity (MVA) Voltage Ratio (HV/LV)<br>Tap change Range (+ % to - %)<br>Percentage Impedance (Positive Sequence at Full load) |

**A.1.2 HYDRO ELECTRIC**

For **SSGS** – Hydro

**A.1.2.1 GENERAL**

| | |
|---|---|
| Site | Give location map to scale showing roads, railway lines, and transmission lines. |
| Site map (To scale) | Showing proposed canal, reservoir area, water conductor system, fore-bay, power house etc. |
| Submerged Area | Give information on area submerged, villages submerged, submerged forest land, agricultural land etc. |
| Whether storage type or run of river type<br>Whether catchment receiving discharges from other reservoir or power plant.<br>Full reservoir level<br>Minimum draw down level.<br>Tail race level<br>Design Head<br>Reservoir level v/s energy potential curve<br>Restraint, if any, in water discharges<br>Approximate period of construction | |

**A.1.2.2 CONNECTION**

| | | |
|---|---|---|
| i | Point of Connection | Give single line diagram proposed Connection with the Transmission System. |
| ii | Step up voltage for Connection (kV) | |

**A.1.2.3 STATION CAPACITY**

| | | |
|---|---|---|
| i | Total **Power Station** capacity (MW) | State whether development is carried out in phases and if so furnish details. |
| ii | No. of units & unit size (MW) | |

**A.1.2.4 GENERATING UNIT DATA**

| | | |
|---|---|---|
| i | Operating Head (in Metres) | a. Maximum<br>b. Minimum<br>c. Average |
| | Hydro Unit | Capability to operate as synchronous condenser Water head versus discharges curve (at full and part load) Power requirement or water discharge while operating as synchronous condenser |
| ii | Turbine | State Type and capacity |
| iii | Generator | Type<br>Rating (MVA)<br>Speed (RPM)<br>Terminal voltage (kV)<br>Rated Power Factor<br>Reactive Power Capability (MVAr) in the range 0.95 of leading and 0.85 of lagging<br>MW & MVAr capability curve of generating unit<br>Short Circuit Ratio<br>Direct axis transient (saturated) reactance (% on rated MVA)<br>Direct axis sub-transient (saturated) reactance (% on rated MVA)<br>Auxiliary Power Requirement (MW) |
| iv | Generator - Transformer | a. Type<br>b. Rated Capacity (MVA)<br>c. Voltage Ratio HV/LV<br>d. Tap change Range (+% to -%)<br>e. Percentage Impedance (Positive Sequence at Full Load). |

**A.2 STANDARD PLANNING DATA (TRANSMISSION) For STU and Transmission Licensees**

Note: The compilation of the data is the internal matter of STU, and as such STU shall make arrangements for getting the required data from different Departments of STU/other transmission licensees (if any) to update its Standard Planning Data in the format given below:

| | |
|---|---|
| i | Name of line (Indicating Power Stations and sub-stations to be connected). |
| ii | Voltage of line (kV). |
| iii | No. of circuits. |
| iv | Route length (km). |
| v | Conductor sizes. |
| vi | Line parameters (PU values).<br>a. Resistance/km<br>b. Inductance/km<br>c. Susceptance/ km (B/2) |

| | |
|---|---|
| vii | Approximate power flow expected- MW & MVAr. |
| viii | Terrain of the route- Give information regarding nature of terrain i.e. forest land, fallow land, agricultural and river basin, hill slope etc. |
| ix | Route map (to scale) - Furnish topographical map showing the proposed route showing existing power lines and telecommunication lines. |
| x | Purpose of Connection- Reference to Scheme, wheeling to other States etc. |
| xi | Approximate period of Construction. |

**A.3. STANDARD PLANNING DATA (DISTRIBUTION) For DISCOMs and Distribution Licensees**

**A.3.1 GENERAL**

| | | |
|---|---|---|
| i | Area Map (to scale) | Marking the area in the map of Madhya Pradesh for which Distribution **License** is applied. |
| ii | Consumer Data | Furnish categories of consumers, their numbers and connected loads. |
| iii | Furnish categories of consumers, their numbers and connected loads. | |

**A.3.2 CONNECTION**

| | | |
|---|---|---|
| i | Points of **Connection** | Furnish single line diagram showing points of **Connection** |
| ii | Voltage of supply at points of **Connection** | |
| iii | Names of Grid Sub-Stations feeding the points of **Connection** | |

**A.3.3 LINES AND SUB-STATIONS**

| | | |
|---|---|---|
| i | Line Data | Furnish lengths of line and voltages within the Area. |
| ii | Sub-station Data | Furnish details of 33/11kV sub-station, 11/0.4kV sub-stations, capacitor installations |

**A.3.4 LOADS**

| | |
|---|---|
| i | Loads drawn at points of **Connection**. |
| ii | Details of loads fed at **EHV**, if any. Give name of consumer, voltage of supply, contract demand and name of Grid Sub-station from which line is drawn, length of **EHV** line from Grid Sub-station to consumer's premises. |
| iii | Reactive Power compensation installed |

**A.3.5 DEMAND DATA (FOR ALL LOADS 1 MW AND ABOVE)**

| | | |
|---|---|---|
| i | Type of load | State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads etc. |
| ii | Rated voltage and phase | |
| iii | Electrical loading of equipment | State number and size of motors, types of drive and control arrangements. |

| | | |
|---|---|---|
| iv | Power Factor | |
| v | Sensitivity of load to voltage and frequency of supply. | |
| vi | Maximum Harmonic content of load. | |
| vii | Average and maximum phase unbalance of load | |
| viii | Nearest sub-station from which load is to be fed | |
| ix | Location map to scale | Showing location of load with reference to lines and sub-stations in the vicinity |

**A.3.6 LOAD FORECAST DATA**

Peak load and energy forecast for each category of loads for each of the succeeding 5 years.
Details of methodology and assumptions on which forecasts are based.
If supply is received from more than one sub-station, the sub-station wise break up of peak load and energy projections for each category of loads for each of the succeeding 5 years along with
estimated Daily load curve.
Details of loads 1 MW and above.

| |
|---|
| Name of prospective consumer. |
| Location and nature of load/complex. |
| Sub-Station from which to be fed. |
| Voltage of supply. |
| Phasing of load. |

## APPENDIX B: DETAILED PLANNING DATA

**REFER TO:**
**CHAPTER – 4 RESORUCE ADEQUACY AND SYSTEM PLANNING CODE**
**CHAPTER – 5 CONNECTION CODE**

**B.1 DETAILED PLANNING DATA (GENERATION)**
**PART-I FOR ROUTINE SUBMISSION**
**B.1.1 THERMAL POWER STATIONS**
For ***SSGS*** – Thermal

| | | |
|---|---|---|
| **B.1.1.1** | | **GENERAL** |
| | 1. | Name of **Power Station**. |
| | 2. | Number and capacity of **Generating Units** (MVA). |
| | 3. | Ratings of all major equipments (Boilers and major accessories, Turbines, |
| | | Generator Unit Transformers etc.). |
| | 4. | Single line Diagram of **Power Station** and switchyard. |
| | 5. | Relaying and metering diagram. |
| | 6. | Neutral Grounding of **Generating Units**. |
| | 7. | Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors) |
| | 8. | Earthing arrangements with earth resistance values. |
| **B.1.1.2** | | **PROTECTION AND METERING** |
| | i. | Full description including settings for all relays and protection systems on the |
| | | **Generating Unit**, Generator unit Transformer, Auxiliary Transformer electrical |
| | | motor of major equipments listed, but not limited to, under Sec. 3 (General). |
| | ii. | Full description including settings for all relays installed on all outgoing feeders |
| | | **Power Station** switchyard, Tie circuit breakers, and incoming circuit |
| | iii. | Full description of inter-tripping of circuit breakers at the point or points of |
| | | with the **Transmission System**. |
| | iv. | Most probable fault clearance time for electrical faults on the **User's**. |
| | v. | Full description of operational and commercial metering schemes. |
| **B.1.1.3** | | **SWITCHYARD** |

In relation to interconnecting transformers:

| | |
|---|---|
| i | Rated MVA. |
| ii | Voltage Ratio |
| iii | Vector Group. |
| iv | Positive sequence reactance for maximum, minimum, normal Tap. (% on MVA). |
| v | Positive sequence resistance for maximum, minimum, normal Tap. (% on MVA). |
| vi | Zero sequence reactance (% on MVA). |
| vii | Tap changer Range (+% to -%) and steps. |
| viii | Type of Tap changer. (off/on load). |

In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of **Connection**:

| | |
|---|---|
| i | Rated voltage (kV). |
| ii | Type of circuit breaker (MOCB/ABCB/SF6). |
| iii | Rated short circuit breaking current (kA) 3 phase. |
| iv | Rated short circuit breaking current (kA) 1 phase. |
| v | Rated short circuit making current (kA) 3 phase. |
| vi | Rated short circuit making current (kA) 1-phase. |

| | |
|---|---|
| vii | Provisions of auto reclosing with details.<br>(a) Lightning Arresters -<br>(b)Technical data<br>(c) Communication –<br>(d) Details of Communications equipment installed at points of connections.<br>(e) Basic Insulation Level (kV)<br>i. Bus bar.<br>ii. Switchgear.<br>iii. Transformer Bushings<br>iv. Transformer windings. |

**B.1.1.4 GENERATING UNITS**
**Parameters of Generator**

| | |
|---|---|
| i. | Rated terminal voltage (kV). |
| ii. | Rated MVA. |
| iii. | Rated MW. |
| iv. | Speed (rpm) or number of poles. |
| v. | Inertia constant H (MW sec./MVA). |
| vi. | Short circuit ratio. |
| vii. | Direct axis synchronous reactance Xd (% on MVA). |
| viii. | Direct axis (saturated) transient reactance (% on MVA) X'd. |
| ix. | Direct axis (saturated) sub-transient reactance (% on MVA) X"d. |
| x. | Quadrature axis synchronous reactance (% on MVA) Xq. |
| xi. | Quadrature axis (saturated) transient reactance (% on MVA) X'q. |
| xii. | Quadrature axis (saturated) sub-transient reactance (% on MVA) X"q. |
| xiii. | Direct axis transient open circuit time constant (sec) T'do. |
| xiv. | Direct axis sub-transient open circuit time constant (sec) T"do. |
| xv. | Quadrature axis transient open circuit time content (sec) T'qo. |
| xvi. | Quadrature axis transient open circuit time constant (sec) T"qo. |
| xvii. | Stator Resistance (Ohm) Ra. |
| xviii. | Stator leakage reactance (Ohm) X1. |
| xix. | Stator time constant (Sec). |
| xx. | Rated Field current (A). |
| xxi. | Neutral grounding details. |
| xxii. | Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this. |
| xxiii | MW and MVAr Capability curve. |

**B.1.1.5 Parameters of excitation control system:**

| | |
|---|---|
| i | Type of Excitation |
| ii | Maximum field Voltage |
| iii | Minimum field voltage |
| iv | Rated Field Voltage. |
| v | Details of excitation loop in block diagrams showing transfer functions of individual elements using I.E.E.E. symbols. |
| vi | Dynamic characteristics of over - excitation limiter. |
| vii | Dynamic characteristics of under-excitation limiter |

**B.1.1.6 Parameters of governor:**

| | |
|---|---|
| i. | Governor average gain (MW/Hz). |
| ii. | Speeder motor setting range. |
| iii. | Time constant of steam or fuel Governor valve. |

| | |
|---|---|
| iv. | Governor valve opening limits. |
| v. | Governor valve rate limits. |
| vi. | Time constant of Turbine. |
| vii. | Governor block diagram showing transfer functions of individual elements using I.E.E.E. symbols. |

**B.1.1.7 Operational parameters:**

| | |
|---|---|
| i. | Minimum notice required to synchronise a **Generating Unit** from de-synchronisation |
| ii. | Minimum time between synchronizing different **Generating Units** in a **Power Station**. |
| iii. | The minimum block load requirements on synchronizing. |
| iv. | Time required for synchronizing a **Generating Unit** for the following conditions:<br>a. Hot<br>b. Warm<br>c. Cold |
| v. | Maximum Generating Unit loading rates for the following conditions:<br>a. Hot<br>b. Warm<br>c. Cold |
| vi. | Minimum load without oil support (MW). |

**B.1.1.8 GENERAL STATUS**

| | |
|---|---|
| i | Detailed Project report. |
| ii | Status Report<br>(a) Land<br>(b) Coal<br>(c) Water<br>(d) Environmental clearance<br>(e) Rehabilitation of displaced persons |
| iii | Techno-economic approval by **Central Electricity Authority** (**CEA**). |
| iv | Approval of **State** Government/Government of India. |
| v | Financial Tie-up. |

**B.1.1.9 CONNECTION**

i. Reports of Studies for parallel operation with the **State Transmission System**.

| | |
|---|---|
| (a) | Short Circuit studies |
| (b) | Stability Studies. |
| (c) | Load Flow Studies. |

ii. Proposed **Connection** with the **State Transmission System**.

| | |
|---|---|
| (a) | Voltage |
| (b) | No. of circuits |
| (c) | Point of **Connection**. |

**B.1.2 HYDRO - ELECTRIC STATIONS**

For **SSGS** – Hydro

**B.1.2.1 GENERAL**

| | |
|---|---|
| i | Name of **Power Station**. |
| ii | No and capacity of units. (MVA) |
| iii | Ratings of all major equipment.<br>a) Turbines (HP)<br>b) Generators (MVA)<br>c) Generator Transformers (MVA)<br>d) Auxiliary Transformers (MVA) |

| | |
|---|---|
| iv | Single line diagram of **Power Station** and switchyard. |
| v | Relaying and metering diagram. |
| vi | Neutral grounding of Generator. |
| vii | Excitation control. |
| viii | Earthing arrangements with earth resistance values. |
| ix | Reservoir Data.<br>a) Salient features<br>b) Type of Reservoir<br>i. Multipurpose<br>ii. For Power<br>c) Operating Table with<br>i. Area capacity curves and<br>ii. Unit capability at different net heads |

**B.1.2.2 PROTECTION**

| | |
|---|---|
| i | Full description including settings for all relays and protection systems installed on the **Generating Unit**, Generator transformer, auxiliary transformer and electrical motor of major equipment included, but not limited to those listed, under Sec. 3 (General). |
| ii | Full description including settings for all relays installed on all outgoing feeders from **Power Station** switchyard, tiebreakers, and incoming breakers. |
| iii | Full description of inter-tripping of breakers at the point or points of **Connection** with the **Transmission System**. |
| iv | Most Probable fault clearance time for electrical faults on the **User**'s System. |

**B.1.2.3 SWITCHYARD**

(a) Interconnecting transformers:

| | |
|---|---|
| i | Rated MVA |
| ii | Voltage Ratio |
| iii | Vector Group |
| iv | Positive sequence reactance for maximum, minimum and normal Tap.(% on MVA). |
| v | Positive sequence resistance for maximum, minimum and normal Tap.(% on MVA). |
| vi | Zero sequence reactance (% on MVA) |
| vii | Tap changer range (+% to -%) and steps. |
| viii | Type of Tap changer (off/on load). |
| ix | Neutral grounding details. |

(b) Switchgear (including circuit breakers, Isolators on all circuits connected to the points of **Connection**).

| | |
|---|---|
| i | Rated voltage (kV). |
| ii | Type of Breaker (MOCB/ABCB/SF6). |
| iii | Rated short circuit breaking current (kA) 3 phase. |
| iv | Rated short circuit breaking current (kA) 1 phase. |
| v | Rated short circuit making current (kA) 3 phase. |
| vi | Rated short circuit making current (kA) 1 phase. |
| vii | Provisions of auto reclosing with details. |

(c) Lightning Arresters

Technical data

(d) Communications

Details of Communications equipment installed at points of connections.

(a) Basic Insulation Level (kV)

| | |
|---|---|
| i | Bus bar. |
| ii | Switchgear. |
| iii | Transformer Bushings |
| iv | Transformer windings. |

**B.1.2.4 GENERATING UNITS**

(a) Parameters of Generator

| | |
|---|---|
| i. | Rated terminal voltage (kV). |
| ii. | Rated MVA. |
| iii. | Rated MW. |
| iv. | Speed (rpm) or number of poles. |
| v. | Inertia constant H (MW sec./MVA). |
| vi. | Short circuit ratio. |
| vii. | Direct axis synchronous reactance Xd (% on MVA). |
| viii. | Direct axis (saturated) transient reactance (% on MVA) X'd. |
| ix. | Direct axis (saturated) sub-transient reactance (% on MVA) X"d. |
| x. | Quadrature axis synchronous reactance (% on MVA) Xq. |
| xi. | Quadrature axis (saturated) transient reactance (% on MVA) X'q. |
| xii. | Quadrature axis (saturated) sub-transient reactance (% on MVA) X"q. |
| xiii. | Direct axis transient open circuit time constant (sec) T'do. |
| xiv. | Direct axis sub-transient open circuit time constant (sec) T"do. |
| xv. | Quadrature axis transient open circuit time content (sec) T'qo. |
| xvi. | Quadrature axis transient open circuit time constant (sec) T"qo. |
| xvii. | Stator Resistance (Ohm) Ra. |
| xviii. | Stator leakage reactance (Ohm) X1. |
| xix. | Stator time constant (Sec). |
| xx. | Rated Field current (A). |
| xxi. | Neutral grounding details. |
| xxii. | Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this. |
| xxiii. | Type of Turbine. |
| xxiv. | Operating Head (Metres) |
| xxv. | Discharge with full gate opening (cumecs) |
| xxvi. | Speed Rise on total Load throw off (%). |
| xxvii. | MW and MVAr Capability curve |

(b)

| | |
|---|---|
| Parameters of excitation control system: | As applicable to thermal **Power Stations** |

(c)

| | |
|---|---|
| Parameters of governor: | As applicable to thermal **Power Station** |

(d) Operational parameter:

| | |
|---|---|
| i | Minimum notice required to Synchronise a **Generating Unit** from de-synchronisation. |
| ii | Minimum time between Synchronising different **Generating Units** in a **Power Station**. |
| iii | Minimum block load requirements on Synchronising. |

**B.1.2.5 GENERAL STATUS**

| | |
|---|---|
| i | Detailed Project Report. |
| ii | Status Report.<br>(a) Topographical survey<br>(b) Geological survey<br>(c) Land<br>(d) Environmental Clearance<br>(e) Rehabilitation of displaced persons. |
| iii | Techno-economic approval by Central Electricity Authority |
| iv | Approval of State Government/Government of India. |
| v | Financial Tie-up. |
| i | Detailed Project Report. |
| ii | Status Report.<br>(a) Topographical survey<br>(b) Geological survey<br>(c) Land<br>(d) Environmental Clearance<br>(e) Rehabilitation of displaced persons. |
| iii | Techno-economic approval by Central Electricity Authority |

**B.1.2.6 CONNECTION**

i. Reports of Studies for parallel operation with the **State Transmission System**.

| | |
|---|---|
| (a) | Short Circuit studies |
| (b) | Stability Studies. |
| (c) | Load Flow Studies. |

ii. Proposed **Connection** with the **State Transmission System**.

| | |
|---|---|
| (a) | Voltage |
| (b) | No. of circuits |
| (c) | Point of **Connection**. |

**B.1.2.7 RESERVOIR DATA**

(a) Dead Capacity

(b) Live Capacity

**B.1.3 GAS POWER STATIONS**

**For SSGS – Gas**

**B.1.3.1 GENERAL**

| | |
|---|---|
| i | Name of **Power Station**. |
| ii | Number and capacity of **Generating Units** (MVA). |
| iii | Ratings of all major equipments (Turbines, Alternators, Heat Recovery Boiler, Generator Unit Transformers etc.) |
| iv | Single line Diagram of **Power Station** and switchyard. |
| v | Relaying and metering diagram. |
| vi | Neutral Grounding of **Generating Units**. |
| vii | Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors) |
| viii | Earthing arrangements with earth resistance values. |
| ix | Start up Engine |
| x | Turbine Details |

**B.1.3.2 PROTECTION AND METERING**

| | |
|---|---|
| i | Full description including settings for all relays and protection systems installed on the Generating Unit, Generator unit Transformer, Auxiliary Transformer and electrical motor of major equipments listed, but not limited to, under Sec. 3 (General). |

| | |
|---|---|
| ii | Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, Tie circuit breakers, and incoming circuit breakers. |
| iii | Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System. |
| iv | Most probable fault clearance time for electrical faults on the User's System. |
| v | . Full description of operational and commercial metering schemes. |

**B.1.3.3 SWITCHYARD**

In relation to interconnecting transformers:

| | |
|---|---|
| i | Rated MVA. |
| ii | Voltage Ratio |
| iii | Vector Group. |
| iv | Positive sequence reactance for maximum, minimum, normal Tap.(% on MVA). |
| v | Positive sequence resistance for maximum, minimum, normal Tap.(% on MVA). |
| vi | Zero sequence reactance (% on MVA). |
| vii | Tap changer Range (+% to -%) and steps. |
| viii | Type of Tap changer. (off/on load). |

In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of Connection:

| | |
|---|---|
| i | Rated voltage (kV). |
| ii | Type of circuit breaker (MOCB/ABCB/SF6). |
| iii | Rated short circuit breaking current (kA) 3 phase. |
| iv | Rated short circuit breaking current (kA) 1 phase. |
| v | Rated short circuit making current (kA) 3 phase. |
| vi | Rated short circuit making current (kA) 1-phase. |
| vii | Provisions of auto reclosing with details. Lightning Arresters - Technical data<br>Communication -<br>Details of communication equipment installed at points of connections.<br>Basic Insulation Level (kV) -<br>i. Bus bar.<br>ii. Switchgear.<br>iii. Transformer bushings.<br>iv. Transformer windings. |

**B.1.3.4 GENERATING UNITS**

**(a) Parameters of Generating Units:**

| | |
|---|---|
| i | Rated terminal voltage(kV). |
| ii | Rated MVA. |
| iii | Rated MW. |
| iv | Speed (rpm) or number of poles. |
| v | Inertia constant H (MW Sec./MVA). |
| vi | Short circuit ratio. |
| vii | Direct axis synchronous reactance (% on MVA) Xd. |
| viii | Direct axis (saturated) transient reactance (% on MVA) Xd'. |
| ix | Direct axis (saturated) sub-transient reactance (% on MVA) Xd". |
| x | Quadrature axis synchronous reactance (% on MVA)Xq . |
| xi | Quadrature axis (saturated) transient reactance (% on MVA) Xq'. |
| xii | Quadrature axis (saturated) sub-transient reactance (% on MVA) Xq". |
| xiii | Direct axis transient open circuit time constant (Sec) T'do. |

| | |
|---|---|
| xiv | Direct axis sub-transient open circuit time constant (Sec) T"do. |
| xv | Quadrature axis transient open circuit time constant (Sec) T'qo. |
| xvi | Quadrature axis sub-transient open circuit time constant (Sec) T"qo. |
| xvii | Stator Resistance (Ohm) Ra. |
| xviii | Neutral grounding details. |
| xix | Stator leakage reactance (Ohm) X1 |
| xx | Stator time constant (Sec). |
| xxi | Rated Field current (A). |
| xxii | Open Circuit saturation characteristic for various terminal Voltages giving the compounding current to achieve the same. |
| xxiii | MW and MVAr Capability curve |

**B.1.3.5 Parameters of excitation control system:**

| | |
|---|---|
| i | Type of Excitation. |
| ii | Maximum Field Voltage. |
| iii | Minimum Field Voltage. |
| iv | Rated Field Voltage. |
| v | Details of excitation loop in block diagrams showing transfer functions of individual elements using I.E.E.E. symbols. |
| vi | Dynamic characteristics of over - excitation limiter. |
| vii | Dynamic characteristics of under-excitation limiter. |

**B.1.3.6 Parameters of governor:**

| | |
|---|---|
| i | Governor average gain (MW/Hz). |
| ii | Speeder motor setting range. |
| iii | Time constant of steam or fuel Governor valve. |
| iv | Governor valve opening limits. |
| v | Governor valve rate limits. |
| vi | Time constant of Turbine. |
| vii | Governor block diagram showing transfer functions of individual elements using I.E.E.E. symbols. |

**B.1.3.7 Operational parameters:**

| | |
|---|---|
| i | Minimum notice required synchronising a Generating Unit from de-synchronization. |
| ii | Minimum time between synchronizing different Generating Units in a Power Station. |
| iii | The minimum block load requirements on synchronizing. |
| iv | Time required for synchronizing a Generating Unit for the following conditions:<br>a. Hot<br>b. Warm<br>c. Cold |
| v | Maximum Generating Unit loading rates for the following conditions:<br>a. Hot<br>b. Warm<br>c. Cold |
| vi | Minimum load without oil support (MW). |

**B.1.3.8 GENERAL STATUS**

| | |
|---|---|
| i | Detailed Project report |
| ii | Status Report<br>(a) Land<br>(b) Gas/Liquid Fuel<br>(c) Water |

| | |
|---|---|
| | (d) Environmental clearance<br>(e) Rehabilitation of displaced persons |
| iii | Approval of **State** Government/Government of India. |
| iv | Financial Tie-up. |

**B.1.3.9 CONNECTION**

i. Reports of Studies for parallel operation with the State Transmission System.

| | |
|---|---|
| (a) | Short Circuit studies |
| (b) | Stability Studies. |
| (c) | Load Flow Studies. |

ii. Proposed Connection with the State Transmission System.

| | |
|---|---|
| (a) | Voltage |
| (b) | No. of circuits |
| (c) | Point of Connection. |

**B.2 DETAILED PLANNING DATA - TRANSMISSION**

For STU and Transmission Licensees

**B.2.1 GENERAL**

i. Single line diagram of the Transmission System down to 33kV bus at Grid Sub-station detailing:

| | |
|---|---|
| (a) | Name of Sub-station. |
| (b) | Power Station connected. |
| (c) | Number and length of circuits. |
| (d) | Interconnecting transformers. |
| (e) | Sub-station bus layouts. |
| (f) | Power transformers. |
| (g) | Reactive compensation equipment. |

ii. Sub-station layout diagrams showing:

| | |
|---|---|
| (a) | Bus bar layouts. |
| (b) | Electrical circuitry, lines, cables, transformers, switchgear etc. |
| (c) | Phasing arrangements. |
| (d) | Earthing arrangements. |
| (e) | Switching facilities and interlocking arrangements. |
| (f) | Operating voltages. |
| (g) | Numbering and nomenclature:<br>i. Transformers.<br>ii. Circuits.<br>iii. Circuit breakers.<br>iv. Isolating switches. |

**B.2.2 LINE PARAMETERS (for all circuits)**

| | |
|---|---|
| i | Designation of Line. |
| ii | Length of line(km). |
| iii | Number of circuits. |
| iv | Per Circuit values.<br>(a) Operating voltage (kV).<br>(b) Positive Phase sequence reactance (pu on 100 MVA) X1<br>(c) Positive Phase sequence resistance (pu on 100 MVA) R1<br>(d) Positive Phase sequence susceptance (pu on 100 MVA) B1<br>(e) Zero Phase sequence reactance (pu on 100 MVA) X0<br>(f) Zero Phase sequence resistance (pu on 100 MVA) R0<br>(g) Zero Phase sequence susceptance (pu on 100 MVA) B0 |

**B.2.3 TRANSFORMER PARAMETERS (For all transformers)**

| | | |
|---|---|---|
| | i. | Rated MVA |
| | ii. | Voltage Ratio |
| | iii. | Vector Group |
| | iv. | Positive sequence reactance, maximum, minimum and normal (pu on 100 MVA) X1 |
| | v. | Positive sequence resistance, maximum, minimum and normal (pu on 100 MVA) R1 |
| | vi. | Zero sequence reactance (pu on 100 MVA). |
| | vii. | Tap change range (+% to -%) and steps. |
| | viii. | Details of Tap changer. (Off/On load). |
| **B.2.4** | | **EQUIPMENT DETAILS (For all sub-stations)** |
| | i. | Circuit Breakers |
| | ii. | Isolating switches |
| | iii. | Current Transformers |
| | iv. | Potential Transformers |
| **B.2.5** | | **RELAYING AND METERING** |
| | i. | Relay protection installed for all transformers and feeders along with their settings and |
| | | level of co-ordination with other Users. |
| | ii. | Metering Details. |

| | | |
|---|---|---|
| **B.2.6** | | **SYSTEM STUDIES** |
| | i. | Load Flow studies (Peak and lean load for maximum hydro and maximum thermal generation). |
| | ii. | Transient stability studies for three-phase fault in critical lines. |
| | iii. | Dynamic Stability Studies |
| | iv. | Short circuit studies (three-phase and single phase to earth) |
| | v. | Transmission and Distribution Losses in the Transmission System. |
| **B.2.7** | | **DEMAND DATA (For all sub-stations)** |
| | i. | Demand Profile (Peak and lean load). |
| **B.2.8** | | **REACTIVE COMPENSATION EQUIPMENT** |
| | i. | Type of equipment (fixed or variable). |
| | ii. | Capacities and/or Inductive rating or its operating range in MVAr. |
| | iii. | Details of control. |
| | iv. | Point of Connection to the System. |

**B.3. DETAILED PLANNING DATA (DISTRIBUTION)**

For DISCOMs /Distribution Licensees

**B.3.1 GENERAL**

| | |
|---|---|
| i | Distribution map (To scale). Showing all lines up to 11kV and sub-stations belonging to the Supplier. |
| ii | Single line diagram of Distribution System (showing distribution lines from points of Connection with the Transmission System, 33/11kV sub stations, 11/0.4kV sub station, consumer bus if fed directly from the Transmission System). |
| iii | Numbering and nomenclature of lines and sub-stations (Identified with feeding Grid sub-stations of the Transmission and concerned 33/11kV sub-station of Supplier). |

**B.3.2 CONNECTION**

| | |
|---|---|
| i | Points of Connection (Furnish details of existing arrangement of Connection). |
| ii | Details of metering at points of Connection. |

**B.3.3 LOADS**

| | |
|---|---|
| i | Connected load - Active and Reactive Load. Furnish consumer details, Number of Consumers category wise, details of loads 1 MW and above, power factor. |
| ii | Information on diversity of load and coincidence factor. |
| iii | Daily demand profile (current and forecast) on each 33/11kV sub-station. |
| iv | Cumulative demand profile of Distribution System (current & forecast). |

## APPENDIX C: OPERATIONAL PLANNING DATA

**C.1 OUTAGE PLANNING DATA**

**REFER TO:**

**CHAPTER -11 OUTAGE PLANNING CODE**

**C.1.1 DEMAND ESTIMATES**

**For DISCOMs /Distribution Licensees**

| Items | Due date / Time |
|---|---|
| Estimated aggregate annual sales of Energy in Million Units and peak and lean demand in MW & MVAr at each Connection point for the next financial year. | To be as per format of Detailed Procedure |
| Estimated aggregate monthly sales of Energy in million Units and peak and lean demand in MW & MVAr at each Connection point for the next month. | |
| Hourly demand estimates for the day ahead. | |

**C.1.2 ESTIMATES OF LOAD SHEDDING**

**For DISCOMs/Distribution Licensee**

| Items | Due date / Time |
|---|---|
| Details of discrete load blocks that may be shed to comply with instructions issued by SLDC when required, from each Connection point. | To be as per format of Detailed Procedure |

**C.1.3 YEAR AHEAD OUTAGE PROGRAMME (For the financial year)**

**C.1.3.1 GENERATOR OUTAGE PROGRAMME**

**For SSGS**

| Items | Due date / Time |
|---|---|
| Identification of Generating Unit. | To be as per format of Detailed Procedure |
| MW, which will not be available as a result of Outage. | |
| Preferred start date and start-time or range of start dates and start times and period of Outage. | |
| If outages are required to meet statutory requirements, then the latest- date by which Outage must be taken. | |

**C.1.3.2 YEAR AHEAD NERPC OUTAGE PROGRAMME (Affecting Transmission System)**

| Items | Due date / Time |
|---|---|
| MW, which will not be available as a result of Outage from Imports through external Connections. | To be as per format of Detailed Procedure |
| Start-date and start-time and period of Outage. | |

**C.1.3.3 YEAR AHEAD CGP's OUTAGE PROGRAMME**

| Items | Due date / Time |
|---|---|
| MW, which will not be available as a result of Outage | To be as per format of Detailed Procedure |
| Start-date and start-time and period of Outage. | |

**C.1.3.4 YEAR AHEAD DISCOMs OUTAGE PROGRAMME**

| Items | Due date / Time |
|---|---|
| Loads in MW not available from any Connection point. | To be as per format of Detailed Procedure |
| Identification of Connection point. | |
| Period of suspension of Drawal with start-date and start-time. | |

**C.1.3.5 STU's OVERALL OUTAGE PROGRAMME**

| **Item** | **Due date/Time** |
|---|---|
| Report on proposed Outage programme to | To be as per format of Detailed Procedure |

| **NERPC** | |
|---|---|
| Release of finally agreed Outage plan | |

**C- 2. GENERATION SCHEDULING DATA**
**REFER TO CHAPTER -8: SCHEDULE AND DESPATCH CODE**
**C-3 CAPABILITY DATA**
**REFER TO:**
**CHAPTER -9: <u>FREQUENCY AND VOLTAGE MANAGEMENT CODE</u>**
For SSGS

| **Item** | Due date / Time |
|---|---|
| Generators and IPPs shall submit to SLDC up-to-date capability curves for all Generating Units. | On receipt of request from STU/ SLDC. |
| CGPs shall submit to STU net return capability that shall be available for Export/Import from Transmission System. | On receipt of request from STU/ SLDC. |

**C-4 <u>RESPONSE TO FREQUENCY CHANGE</u>**
**REFER TO:**
**CHAPTER -9: <u>FREQUENCY AND VOLTAGE MANAGEMENT CODE</u>**
For SSGS

| **Item** | Due date / Time |
|---|---|
| Primary Response in MW at different levels of loads ranging from minimum Generation to registered capacity for frequency changes resulting in fully opening of governor valve. | On receipt of request from STU/ SLDC. |
| Secondary response in MW to frequency changes | On receipt of request from STU/ SLDC. |

**C-5 MONITORING OF GENERATION**
**REFER TO:**
**CHAPTER -10: <u>MONITORING OF GENERATION AND DRAWAL CODE</u>**
For SSGS

| Items | Due date / Time |
|---|---|
| SSGS shall provide hourly generation summation to SLDC. | Real time basis |
| CGPs shall provide hourly export/ import MW to SLDC. | Real time basis |
| Logged readings of Generators to SLDC. | As required |
| Detailed report of Generating Unit tripping on monthly basis. | In the first week of the succeeding month |

**C-6 ESSENTIAL AND NON-ESSENTIAL LOAD DATA**
**REFER TO:**
**CHAPTER -12 <u>CONTINGENCY PLANNING CODE</u>**
**For DISCOMs /Distribution Licensee**

| Items | Due date / Time |
|---|---|
| Schedule of essential and non-essential loads on each discrete load block for purposes of load shedding. | As soon as possible after Connection |

**APPENDIX D: PROTECTION DATA**
**REFER TO:**
**CHAPTER -15 – PROTECTION CODE**

| **Item** | Due date / Time |
|---|---|
| **For SSGS**<br>Generators / CGPs / IPPs shall submit details of protection requirement and schemes installed by them as referred to in B-1. Detailed Planning Data under "Protection And Metering". | As applicable to Detailed Planning Data |
| **For STU /Transmission Licensee**<br>The STU shall submit details of protection equipment and schemes installed by them as referred to in B-2. Detailed system Data, Transmission under "Relaying and Metering" in relation to Connection with any User. | As applicable to Detailed Planning Data |

**APPENDIX E: METERING DATA**
**REFER TO:**
**CHAPTER – 16 TRANSMISSION METERING CODE**

| Item | Due date / Time |
|---|---|
| **For SSGS**<br>SSGS shall submit details of metering equipment and scheme installed by them as referred in **B-1. Detailed Planning Data under "Protection and Metering".** | As applicable to Detailed Planning Data |
| **For STU /Transmission Licensee**<br>**STU** shall submit details of metering equipment and schemes installed by them as referred in **B-2. Detailed System Data, Transmission under "Relaying and Metering" in relation to Connection** with any User. | As applicable to Detailed Planning Data |

## APPENDIX F: PLANNING STANDARDS

**REFER TO:**

**CHAPTER –4 RESOURCE ADEQUACY AND SYSTEM PLANNING CODE**

**General Policy**

The State Transmission System planning and generation expansion planning shall be in accordance with the provisions of Manual on Transmission Planning Criteria issued by CEA and other guidelines. However, some planning parameters of the State Transmission System may vary according to directives of MPERC.

**Planning Criterion**

(a) The planning criterion is based on the security philosophy on which ISTS and State Transmission System has been planned. The security philosophy shall be as per Manual on Transmission Planning Criteria and other CEA guidelines. The general policy shall be as detailed below:

(i) As a general rule, the ISTS/STS shall be capable of withstanding and secured against the following contingency outages without necessitating load shedding or rescheduling of generation during Steady State Operations:

- Outage of a 132kV D/C line or,
- Outage of a 220kV D/C line or,
- Outage of a 400kV S/C line or,
- Outage of a single Interconnecting Transformer, or,
- Outage of one pole of HVDC Bipole line, or,
- Outage of a 765kV S/C line.

(ii) The above contingencies shall be considered assuming a pre-contingency system depletion (Planned Outage) of another 220kV D/C line or 400kV S/C line in another corridor and not emanating from same sub-station. All the generating Units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified.

(b) The ISTS/STS shall be capable of withstanding the loss of most severe single system in feed without loss of stability.

(c) Any one of these events defined above shall not cause:

| | |
|---|---|
| i | Loss of supply |
| ii | Prolonged operation of the system frequency below and above specified limits |
| iii | Unacceptable high or low voltage |
| iv | System instability |
| v | Unacceptable overloading of ISTS/STS elements |

**APPENDIX G SITE RESPONSIBILITY SCHEDULE**
**REFER TO: CHAPTER – 5: CONNECTION CODE**

| Item of Plant/ Apparatus | Plant Owner | Safety Responsibility | Control Responsibility | Operation Responsibility | Maintenance Responsibility | Remarks |
|---|---|---|---|---|---|---|
| ......kV Switchyard | | | | | | |
| All equipment including bus bars | | | | | | |
| Feeders | | | | | | |
| | | | | | | |
| Generating Units | | | | | | |
| | | | | | | |

Name of Power Station/Sub-Station
Site Owner: Tel. Number: Fax Number:

**APPENDIX H: INCIDENT REPORTING**
**REFER TO:**
**CHAPTER – 14: Reports**
**Operational Event/ Incidence reporting**

| FLASH REPORT : SLDC/STU/USERS/TRANSIMISSION LICENSEE/GENERATORS | | | |
|---|---|---|---|
| **Agency Name/Month-Year/GD or GI- Number** | | | |
| **Name of Incident: .** | | | |
| **1. Date and Time:** | | | |
| **2. Antecedent Conditions** | | | |
| I. Frequency of NEW Grid/SR Grid | | | |
| **Event** | **Frequency** | **Time(hh:mm)** | |
| Pre incident | | | |
| Post Incident | | | |
| II. Demand Met - MW | | | |
| State Generation - MW | | | |
| State Load - MW | | | |
| **3. Event Description**: Event and Likely cause as reported by SLDC./State Entities and as observed. | | | |
| **4. Lines/ICT/Units tripped and Restoration** | | | |
| **Lines/ICT/Unit Tripped** | **Load prior to fault** | **Tripping time** | **Restoration Time** |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| **5. Areas Affected By Disturbance :** | | | |
| **6. Load Loss :** | | | |
| **7. Generation Loss :** | | | |
| 8. SUPPLY RESUMED FROM | | | |

## APPENDIX -I: REQUIRED DETAILS OF APPLICANT FOR CONNECTIVITY OF PROJECT WITH INTRA STATE TRANSMISSION SYSTEM

**REFER TO:**
**CHAPTER 5: CONNECTION CODE**

| Sl. No. | PARTICULAS | DESCRIPTION |
|---|---|---|
| 1 | Name & Address of the company with Registered Office, Telephone / Mobile No., Fax No. and E-mail address. | |
| 2 | Name, Designation and Address of the Developer/ Person-in charge, Telephone/Mobile No., Fax No. and Email address | |
| 3 | Location (Village, Tehsil, District) of the project Site with Geographical Map (showing longitude and latitude of the project location) and KMZ file indicating the location of the project | |
| 4 | Type of Project : (Wind/Solar/Captive/Other) | |
| 5 | Project Capacity (in MW) | |
| 6 | Schedule Timeline of Commissioning of the Project | |
| 7 | Sub-station from where connectivity is desired and distance from the project site | |
| 8 | Voltage Level at which connectivity is required (kV) | |
| 9 | No. of units and capacity of power plant (in MW) and Expected date of commissioning of the project. | |
| 10 | Complete Technical details of Wind/Solar power plant including DPR of the project | |
| 11 | Copy of Detailed Project Report (DPR) of the project including SLD & Layout of Proposed Plant. The grant of grid connectivity will be subject to compliance of CEA Safety Regulations and amendments thereof. | |
| 12 | Details of land acquisition along with location of pooling sub-station of project marked on the Patwari Map with Coordinates (Longitude/Latitude) | |
| 13 | Copy of registration of the project with AEDA/APDCL (Nodal agency for renewable projects) / Copy of MoU between Developer & GoA. | |
| 14 | Copy of the Comfort Letter / Wind Power Development Agreement (WPDA) executed with New and Renewal Energy Department (NRED)/AEDA/APDCL | |
| 15 | Copy of your RE project registration certificate issued by CEA, GoI, New Delhi as Renewable Energy Project registry is maintained by CEA, GoI. The CEA registration can be done through e-portal. | |
| 16 | Final clearance / sanction from NRED/AEDA/APDCL compliance report | |
| 17 | Name, address & location of the beneficiary of the project | |
| 18 | Point of drawal of the beneficiary | |
| 19 | Copy of PPA between Project Developers & Beneficiaries | |
| 20 | Whether applying for LTOA / MTOA | |
| 21 | Copies of the Statutory clearance obtained from the State Govt./ Central Govt. including NRED/ AEDA/APDCL Registration, CEA Registration, Valid title of land, Forest clearance, Environmental clearance, Clearance from Urban/ Rural bodies, Power line clearances, Clearance from Highways/ Aviation & Roads/ concerned authorities like Gas pipelines, water pipeline or any other communication network in making interference etc. as and when applicable. | |

## APPENDIX -J: THIRD PARTY PROTECTION SYSTEM CHECKING & VALIDATION TEMPLATE FOR A SUB-STATION

**REFER TO:**
**CHAPTER 15: Protection Code**

**1.** INTRODUCTION

(i) The audit reports, along with action plan for rectification of deficiencies found, if any, shall be submitted to SPCC and/or SLDC within a month of submission of report by auditor.

(ii) The third party protection system checking shall be carried at site by the designated agency. The agency shall furnish two reports:

(a) Preliminary Report: This report shall be prepared on the site and shall be signed by all the parties present.

(b) Detailed Report: This report shall be furnished by agency within one month after carrying out detailed analysis.

**2.** CHECKLIST

(i) The protection system checklist shall contain information as per this Regulation.

(a) General Information (to be provided prior to the checking as well as to be included in final report):

(i) Sub-station name
(ii) Name of Owner Utility
(iii) Voltage Level (s) or highest voltage level?
(iv) Short circuit current rating of all equipment (for all voltage level)
(v) Date of commissioning of the sub-station
(vi) Checking and validation date
(vii) Record of previous tripping's (in last one year) and details of protection operation
(viii) Previous Relay Test Reports
(ix) Overall single line diagram (SLD)
(x) AC aux SLD
(xi) DC aux SLD
(xii) SAS architecture diagram
(xiii) SPS scheme implemented (if any)

(b) The preliminary report shall inter-alia contain the following:

**TABLE: FORMAT OF PRELIMINARY REPORT**

| S.No. | Issues | Remarks |
|---|---|---|
| 1 | Recommendation of last protection checking and validation | Status of works and pending issues if any |
| 2 | Review of existing settings at sub-station | Recommended Action |
| 3 | Disturbance Recorder out available for last 6 tripping's (Y/N) | Recommended Action |
| 4 | Chronic reason of tripping, if any | Recommended Action |
| 5 | Major non-conformity / deficiency observed | Recommended Action |

(c) The relay configuration checklist for available power system elements at station:

(i) Transmission Line

(ii) Bus Reactor/Line Reactor

(iii) Inter-connecting Transformer

(iv) Busbar Protection Relay

(v) AC auxiliary system

(vi) DC auxiliary system

(vii) Communication system

(viii) Circuit Breaker Details

(ix) Current Transformer Details

(x) Capacitive Voltage Transformers Details

(xi) Any other equipment/system relevant for protection system operation

(d) The minimum set of points on which checking and validation shall be carried out is covered in this Regulation. The detailed list shall be prepared by checking and validation team in consultation with concerned entity, SPCC and SLDC.

(i) Transmission Line Distance Protection/Differential Protection

a. Name and Length of Line

b. Whether series compensated or not

c. Mode of communication used (PLCC/OPGW)

d. Relay Make and Model for Main-I and Main-II

e. List of all active protections & settings

f. Carrier aided scheme if any

g. Status of Power Swing/Out of Step/SOTF/Breaker Failure/Broken Conductor / STUB/Fault Locator/DR/VT fuse fail/ Overvoltage Protection /Trip Circuit supervision/Auto-reclose/Load encroachment etc.

h. Relay connected to Trip Coil-1 or 2 or both

i. CT ratio and PT ratio

j. Feed from DC supply-1 or 2

k. Connected to dedicated CT core (mention name)

l. Other requirements for protection checking and validation

(ii) Shunt Reactor & Inter-connecting Transformer Protection

a. Whether two groups of protections used (Group A and Group B)

b. Do the groups have separate DC sources

c. Relay Make and Model

d. List of all active protections along with settings

e. Status of Differential Protection/Restricted Earth Fault Protection/Back-up Directional Overcurrent/Backup Earth fault/ Breaker Failure

f. Status of Oil Temperature Indicator/Winding Temperature Indicator / Bucholz/Pressure Release Device etc.

g. Relay connected to Trip Coil-1 or 2 or both

h. CT ratio and PT ratio

i. Feed from DC supply-1 or 2

j. Connected to dedicated CT core (mention name)

k. Other requirements for protection checking and validation

(iii) Busbar Protection Relay

a. Busbar and redundant relay make and model

b. Type of Busbar arrangement

c. Zones

d. Dedicated CT core for each busbar protection (Yes/No)

e. Breaker Failure relay included (Yes/No), if additional then furnish make and model

f. Trip issued to both Busbar protection in case of enabling

g. Isolator indication and check relays

h. Other requirements for protection checking and validation

(iv) AC auxiliary system

a. Source of AC auxiliary system

b. Supply changeover between sources (Auto/Manual)

c. Diesel generator (DG) details

d. Maintenance plan and supply changeover periodicity in DG

e. Single Line Diagram

f. Other requirements for protection checking and validation

(v) DC auxiliary system

a. Type of Batteries (Make, vintage, model)

b. Status of battery Charger

c. Measured voltage (positive to earth and negative to earth)

d. Availability of ground fault detectors

e. Protection relays and trip circuits with independent DC sources

f. Other requirements for protection checking and validation

g. Communication system

(i) Mode of communication for Main-1 and Main-2 protection

(ii) Mode of communication for data and speech communication

(iii) Status of PLCC channels

(iv) Time synchronization equipment details

(v) OPGW on geographically diversified paths for Main-1 and main-2 relay

(vi) Other requirements for protection checking and validation

(vi) Circuit Breaker Details

a. Details and Status

b. Healthiness of Tripping Coil and Trip circuit supervision relay

c. Single Pole/Multi pole operation

d. Pole Discrepancy Relay available(Y/N)

e. Monitoring Devices for checking the dielectric medium

f. Other requirements for protection checking and validation

(vii) Current Transformer (CT)/Capacitive Voltage Transformer (CVT) Details

a. CT/CVT ID name and voltage level

b. CT/CVT core connection details

c. Accuracy Class

d. Whether Protection/Metering

e. CT/CVT ratio available and ratio adopted

f. Details of last checking and validation of CT/CVT healthiness

g. Other requirements for protection checking and validation

h. Other protections: Direction earth fault, negative sequence, over current, over voltage, over frequency, under voltage, under frequency, forward power, reverse power, out of step/power swing, HVDC protection etc.

**3.** 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).

(ii) The deviations from the RPC protection philosophy, if any and reasons for taking the deviations shall be recorded.

(iii) All the major general deficiency shall be listed in detail along with remedial recommendations.

(iv) The relay settings to be adopted shall be validated with simulation based or EMTP studies and details shall be enclosed in report.

(v) The cases of protection mal-operation shall be analysed from protection indices report furnished by concerned utility, the causes of failure along with corrective actions and recommendations based on the findings shall be noted in the report.

## APPENDIX -K: REACTIVE POWER COMPENSATION

**REFER TO:**
**CHAPTER 9: Frequency and Voltage Management Code**

### 1. REACTIVE POWER COMPENSATION

a) Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The regional entities are therefore expected to provide local VAr compensation or generation such that they do not draw VARs from the EHV grid, particularly under low-voltage condition. To discourage VAr drawals by regional entities, VAr exchanges with ISTS shall be priced as follows:

i. The regional entity pays for VAr drawal when voltage is below 97%

ii. The regional entity gets paid for VAr return when voltage is below 97%.

iii. The regional entity gets paid for VAr drawal when voltage is above103%.

iv. The regional entity pays for VAr return when voltage is above 103%. Where all voltage measurements are at the interface point with ISTS.

b) 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 0.5paise/kVArh per year thereafter, unless otherwise revised.

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 State Deviation and Ancillary Services Pool Account at SLDC. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer.

e) For any interconnecting line between two states, owned by different States, the interface points shall be treated in terms of this Regulation for the purpose of reactive power charges.

2. **ACCOUNTING AND PAYMENT FOR REACTIVE ENERGY EXCHANGES**

a) SLDC shall be responsible to issue the weekly statement for VAR charges, to all state entities.

b) The concerned state entities shall pay the amounts into State Deviation and Ancillary Services Pool Account operated by the SLDC within 10 (ten) days of issue of statement.

c) The state entities who have to receive the money on account of VAR charges would then be paid out from the aforesaid Pool Account, within two (2) working days from the receipt of payment in the Pool Account.

d) If payments against the above VAr charges are delayed by more than two days, i.e., beyond twelve (12) days from issue of the statement by SLDC, the defaulting regional entity shall pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the state entities who had to receive the amount, payment of which got delayed.

e) Persistent payment defaults, if any, shall be reported by the SLDC to the GCMC, for initiating remedial action.

## APPENDIX -L: PROCEDURE SPECIFYING DATA, FORECASTING AND SCHEDULING FOR RENEWABLE ENERGY GENERATING STATIONS (REGS) AT INTER-STATE LEVEL

**REFER TO:**

**CHAPTER 8: Schedule and Despatch Code**

**1. INTRODUCTION**

a) This Procedure contains requirements of data submission by Renewable Energy Generating Station or QCA on behalf of Renewable Energy Generating Station(s), prior to COD and real time and scheduling methodology to be followed for multiple renewable energy generating station(s) connected at a pooling station.

b) The responsibility to provide forecast and other data and to coordinate with SLDC under this Procedure shall be that of Qualified Coordinating Agency on behalf of all generating stations it is representing.

Provided that where Qualified Coordinating Agency is not identified, individual renewable energy generating station or lead generator, as the case may be, shall be responsible for the same.

**2. ROLE OF ENTITIES**

a) QCA or Renewable Energy Generating Station or Lead Generator

i. The individual generating station or Lead Generator shall submit one time details to SLDC as per Annexure-I to this Appendix. Further, if there is any change in the information furnished, then the updated information shall be shared with the SLDC not later than 7 working days of such change.

ii. QCA (for the REGSs it is representing) or REGS (who are not represented through QCA) or Lead Generator shall undertake the following activities:

a. QCA or Lead Generator (for generating stations it is representing) shall undertake technical coordination amongst the generators it is representing, connected at a pooling station.

b. Provide Available Capacity, Day ahead forecast (based on their own forecast or on the forecast done by SLDC) and Schedule as per Annexure-II to this Appendix, through web-based application maintained by SLDC.

c. Provide real time data at turbine/inverter level and generation data at pooling station level as per Annexure-III to this Appendix.

d. Provide monthly data:

I. For wind plants- average wind speed, average power generation for 15-min time block for each turbine

II. For solar plants - average solar irradiation, average power generation at 15-min time block level for all inverters* >=1 MW

* if a solar plant uses only smaller string inverters, then data may be provided at the plant level

e. Be responsible for metering and data collection, transmission and co-ordination with RLDC, SLDC, RPC, CTU and other agencies as per AEGC or IEGC and extant AERC Regulations.

f. Undertake commercial settlement for deviation as per applicable AERC Regulations.

g. Submit a copy of the consent to the SLDC wherein it is mentioned that QCA shall undertake all operational and commercial responsibilities on behalf of generating stations as per the AERC Regulations.

h. Use Automatic meter reading technologies for transfer, analysis and processing of interface meter data.

i. Shall furnish the contract rate(s) along with a copy of the contract(s), for the purpose of Deviation charge account preparation, to SLDC.

j. Shall comply the instruction of SLDC in normal operation as well as emergency condition.

k. Shall establish protocol for communication with individual generators to implement the instructions of SLDC effectively.

l. Shall maintain records and accounts of the time-block wise Schedules, the Actual generation injected and the deviation, for the polling station and individual generator(s) separately.

m. Shall ensure availability of data telemetry at the turbine/inverter level to the SLDC and shall ensure the correctness of the real-time data and undertake the corrective actions, if required. The suggested data telemetry requirement is enclosed at Annexure-III to this Appendix.

n. Keep the SLDC indemnified at all times and shall undertake to indemnify, defend and save the SLDC harmless from any and all damages, losses including commercial losses due to forecasting error, claims and actions including those relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the transactions undertaken by the Generators.

b) SLDC

i. The SLDC shall be responsible for scheduling, communication, coordination with QCA or generating station or Lead Generator.

ii. The SLDC will be responsible for processing the interface meter data and computing the net injections at pooling station represented by each QCA or REGS or Lead Generator, as the case may be, as specified in Annexure- IV to this Appendix.

**3. FORECASTING**

a) QCA or generating station or Lead Generator shall provide the forecast to the SLDC which may be based on their own forecast or SLDC"s forecast as per Annexure- II to this Appendix.

b) QCA or generating station or Lead Generator may prepare their schedule based on the forecast done by SLDC or their own forecast. Any commercial impact on account of deviation from schedule based on the forecast chosen by the QCA shall be borne by the respective QCA.

**4. SCHEDULING AND DESPATCH**

a) Following alternatives exist for Scheduling and Despatch for Generators within Solar / Wind /Hybrid Power parks due to multiple generation developers within the Park injecting at various points with in the park and ultimately injecting at interface with InSTS:

Case-1 QCA has been identified for all generating stations connected at a pooling station.

Case-2 Where QCA at a pooling station is identified for some of the generating stations but not all of generating stations at such pooling station

Case-3 Where QCA at a pooling station is not identified following situations may arise:

Case-A: The SLDC shall be responsible for the scheduling, communication, coordination with RE Generators of 50 MW and above and connected to Intra State Transmission System (ISTS).

Case-B: Lead generator shall be responsible for the coordination and communication with RLDC, SLDC, RPC and other agencies for scheduling of RE Generators individually having less than 50 MW, but collectively having an aggregate installed capacity of 50 MW and above and connected within the solar park.

b) For Case-1, QCA shall be responsible for doing de-pooling of DSM charges as per the mutual agreement between generators and QCA.

c) For Case- 2 and Case- 3, where scheduling and accounting is to be coordinated by SLDC, a representative sketch showing the scheduling is at Annexure-IV.

d) The change of QCA would need a notice period of fifteen (15) days and the changeover shall take place with effect from 0000 hours of a Monday, the first day of weekly settlement cycle.

e) In case of any payment default by the QCA, the generators shall be liable to pay the DSM charges in proportion to their MW capacity.

**ANNEXURE-I**

| Details to be submitted by the Wind/Solar generating stations which are regional entities/ lead generator, principal generator | |
|---|---|
| Type: Wind/Solar Generator | |
| Individual / on Behalf of Group of generators | |
| If on Behalf of Group of generators group of their details of agreement to be attached | |
| Total Installed Capacity of Generating Station | |

| | |
|---|---|
| Total Number of Units with details | |
| Physical Address of the RE Generating Station | |
| Whether any PPA has been signed: (Y/N) | If yes ,then attach details |
| Connectivity Details | Location/Voltage Level |
| Metering Details | Meter No. 1. Main<br>2. Check |
| Connectivity Diagram | (Please Enclose) |
| Static data | As per attached sheet |
| Contact Details of the Nodal Person | Name :<br>Designation :<br>Number: Landline Number, Mobile Number, Fax Number<br>E - Mail Address : |
| Contact Details of the Alternate Nodal Person | Name :<br>Designation :<br>Number: Landline Number, Mobile Number, Fax Number<br>E - Mail Address : |

Data to be submitted by the RE Generator / lead generator, principal generator for Wind turbine generating plants

| S No | Particulars |
|---|---|
| 1 | **Type** |
| 2 | Manufacturer |
| 3 | Make /Model |
| 4 | Capacity |
| 5 | COD |
| 6 | Hub height |
| 7 | Total height |
| 8 | RPM range |
| 9 | Rated wind speed |
| | |
| **Performance Parameters** | |
| 11 | Rated electrical power at rated wind speed |
| 12 | Cut in speed |
| 13 | Cut out speed |
| 14 | Survival speed (Max wind speed) |
| 15 | Ambient temperature for out of operation |
| 16 | Ambient temperature for in operation |
| 17 | Survival temperature |
| 18 | Low Voltage Ride Through (LVRT) setting |
| 19 | High Voltage Ride Through (HVRT) setting |
| 20 | Lightning strength (KA & in coulombs) |
| 21 | Noise power level (db) |
| 22 | Rotor |
| 23 | Hub type |
| 24 | Rotor diameter |
| 25 | Number of blades |
| 26 | Area swept by blades |
| 27 | Rated rotational speed |
| 28 | Rotational Direction |
| 29 | Coning angle |

| | |
|---|---|
| 30 | Tilting angle |
| 31 | Design tip speed ratio |
| **Blade** | |
| 32 | Length |
| 33 | Diameter |
| 34 | Material |
| 35 | Twist angle |
| **Generator** | |
| 36 | Generator Type |
| 37 | Generator no of poles |
| 38 | Generator speed |
| 39 | Winding type |
| 40 | Rated Gen.Voltage |
| 41 | Rated Gen. frequency |
| 42 | Generator current |
| 43 | Rated Temperature of generator |
| 44 | Generator cooling |
| 45 | Generator power factor |
| 46 | KW/MW @ Rated Wind speed |
| 47 | KW/MW @ peak continuous |
| 48 | Frequency Converter |
| 49 | Filter generator side |
| 50 | Filter grid side |
| **Transformer** | |
| 51 | Transformer capacity |
| 52 | Transformer cooling type |
| 53 | Voltage |
| 54 | Winding configuration |
| **Weight** | |
| 55 | Rotor weight |
| 56 | Nacelle weight |
| 57 | Tower weight |
| 58 | **Over speed Protection** |
| 59 | **Design Life** |
| 60 | **Design Standard** |
| 61 | Latitude |
| 62 | Longitude |
| 63 | COD Details |
| 64 | Past Generation History from the COD to the date on which DAS facility provided at RLDC, ifapplicable |
| 65 | Distance above mean sea level |

**For Solar generating Plants: Static data points:**

1. Latitude
2. Longitude
3. Power Curve
4. Elevation and orientation angles of arrays or concentrators

5. The generation capacity of the Generating Facility
6. Distance above mean sea level etc.
7. COD details
8. Rated voltage
9. Details of Type of Mounting: (Tracking Technology if used, single axis or dual axis, auto or manual)
10. Manufacturer and Model (of Important Components, Such as Concentrators, Inverter, Cable. PV Module.Transformer. Cables)
11. DC installed Capacity
12. Module Cell Technology
13. I-V Characteristic of the Module
14. Inverter Rating at different temperature
15. Inverter Efficiency Curve
16. Transformer Capacity & Rating, evacuation voltage, distance form injection point

**ANNEXURE-II**

Forecast and Schedule Data to be submitted by QCA, generator-wiseFORMAT: A (to be submitted a day in advance)

| 15 Min time block (96 Blockina day) | TIME | Available Capacity(MW) - DayAhead | Day Ahead Forecast (MW) | Day Ahead Schedule (MW) |
|---|---|---|---|---|
| 1 | 00:00-00:15 | | | |
| 2 | 00:15-00:30 | | | |
| 3 | 00:30-00:45 | | | |
| 4 | 00:45-01:00 | | | |
| . | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| 94 | | | | |
| 95 | | | | |
| 96 | | | | |

**Note:** The forecast should ideally factor forecasting errors. As such schedule should ordinarily be same as forecast.

FORMAT: B (to be submitted on the day of actual generation, revision of availability and schedule, ifany, shall be done as per this Grid Code.

| **15 Min time block (96 Blockin a day)** | **TIME** | **Day ahea dschedule (MW)** | **Current Available Capacity (MW)** | **Revised Schedule (MW)** |
|---|---|---|---|---|
| 1 | 00:00-00:15 | | | |
| 2 | 00:15-00:30 | | | |
| 3 | 00:30-00:45 | | | |
| 4 | 00:45-01:00 | | | |

| | | | | |
|---|---|---|---|---|
| . | | | | |
| | | | | |
| | | | | |
| | | | | |
| 94 | | | | |
| 95 | | | | |
| 96 | | | | |

## ANNEXURE-III

Real-time Data Telemetry requirement (Suggested List)

**Wind turbine generating plants**

1. Turbine Generation (MW/MVAR)
2. Wind Speed(meter/second)
3. Generator Status (on/off-line)- this is required for calculation of availability of the WTG
4. Wind Direction ( degrees from true north)
5. Voltage(Volt)
6. Ambient air temperature ( ° C )
7. Barometric pressure (Pascal)
8. Relative humidity(in percent)
9. Air Density (kg/m³)

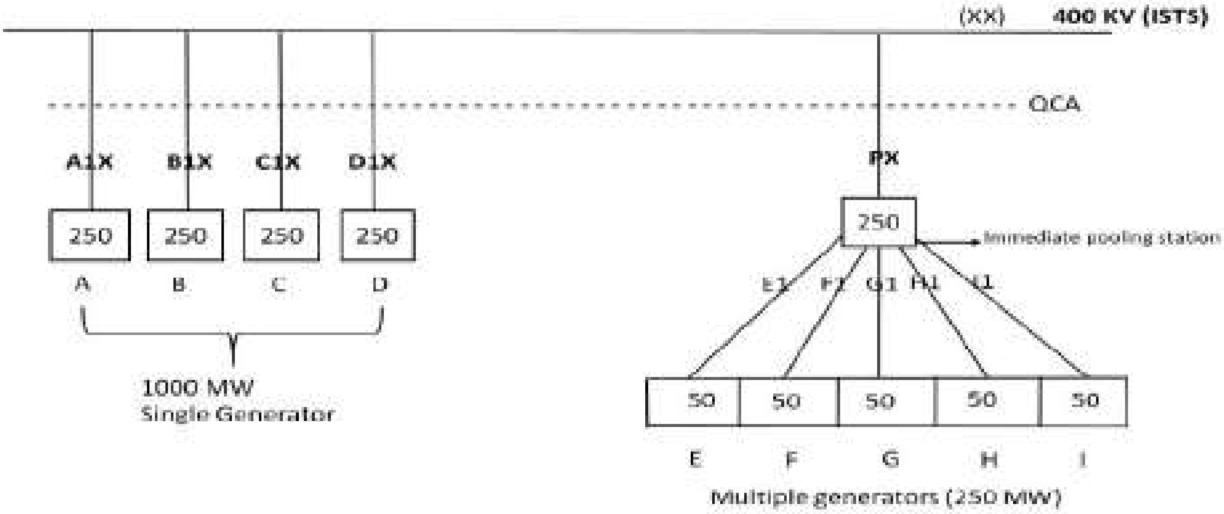
**For Solar generating Plants**

1. Solar Generation unit/ Inverter-wise ( MW and MVAR )
2. Voltage at interconnection point (Volt)
3. Generator/Inverter Status (on/off-line)
4. Global horizontal irradiance (GHI)- Watt per meter square
5. Ambient temperature ( °C)
6. Diffuse Irradiance- Watt per meter square
7. Direct Irradiance- Watt per meter square
8. Sun-rise and sunset timings
9. Cloud cover-(Okta)
10. Rainfall (mm)
11. Relative humidity (%)
12. Performance Ratio

## ANNEXURE-IV

**Block Diagram showing the case wise Scheduling and Forecasting considering a sample case**

**Case-I (QCA responsible for all generators):**

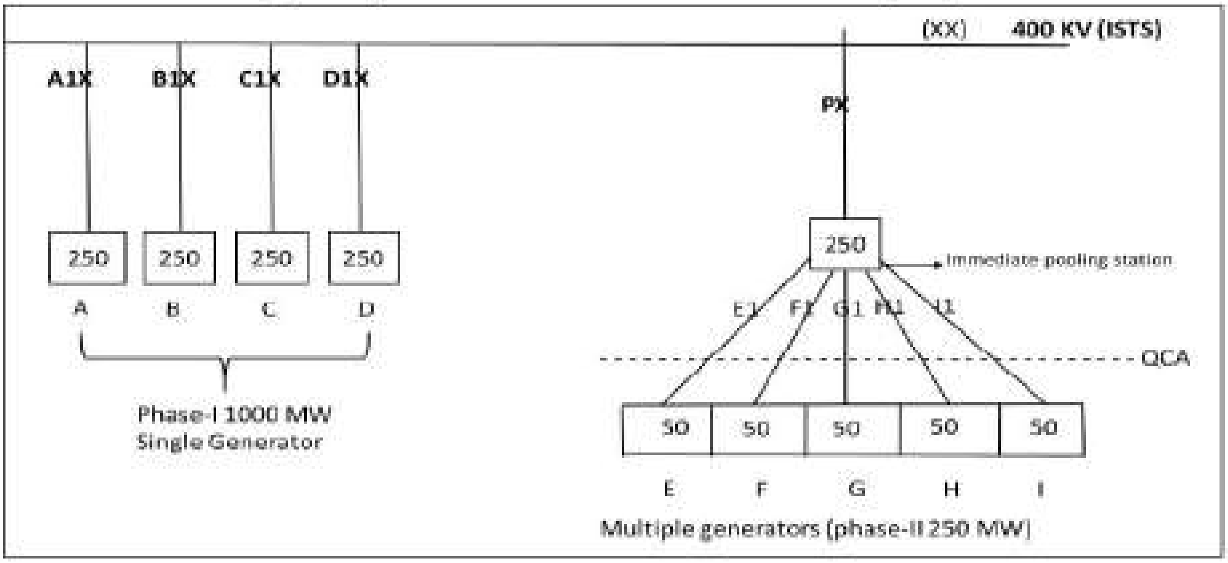



(a) Suppose an REGS of 1000 MW capacity is developed in four blocks namely A,B,C & D of 250 MW capacity each and is directly connected to point A1,B1,C1& D1 respectively at ISTS. Let REGSs of 50 MW each aggregating to 250 MW (5 Nos. namely E, F, G, H & I) be connected to intermediate pooling station. REGSs are connected to interface point E1, F1, G1, H1& I1 and thereby connected to ISTS at XX point.

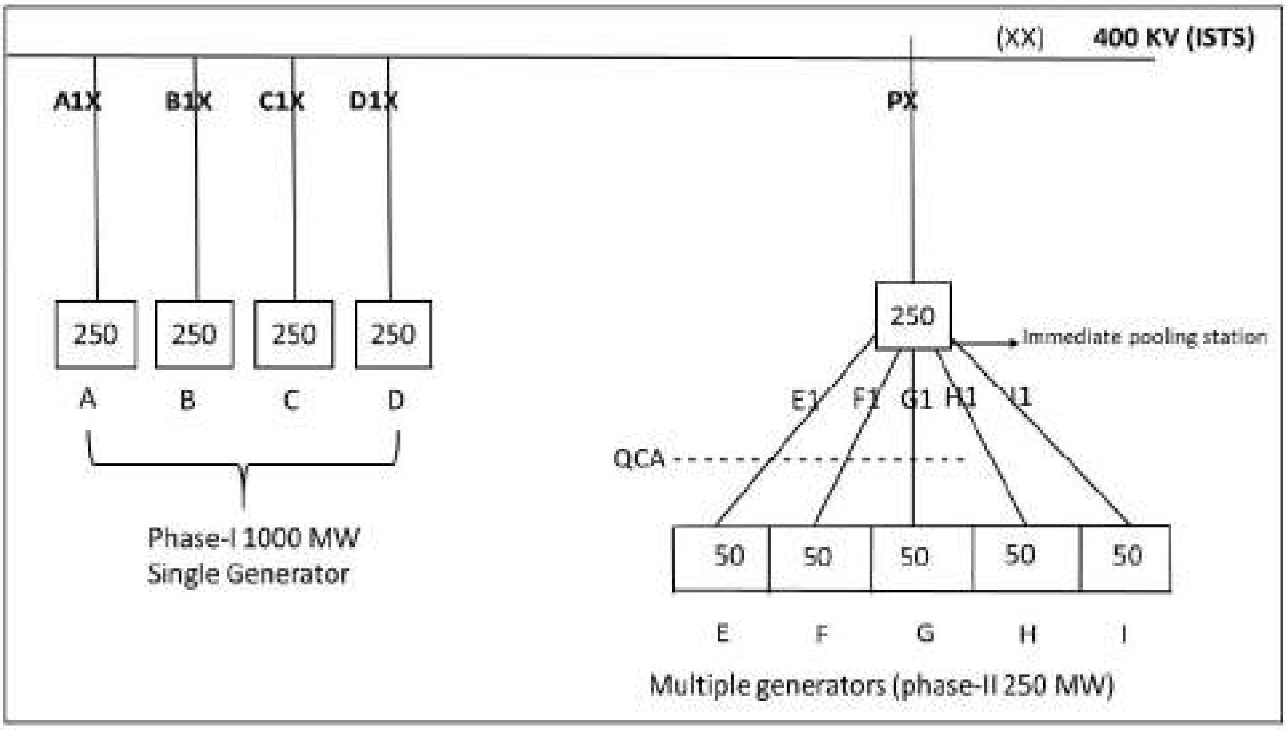
(b) Suppose all the REGSs have mutually agreed to appoint a QCA for all scheduling and forecasting activities, such QCA, shall be responsible for carrying out activities as assigned under this Code.

**Case-2 (QCA responsible for some of the generators):**

**A. QCA is responsible for all REGS connected at Intermediate pooling station**

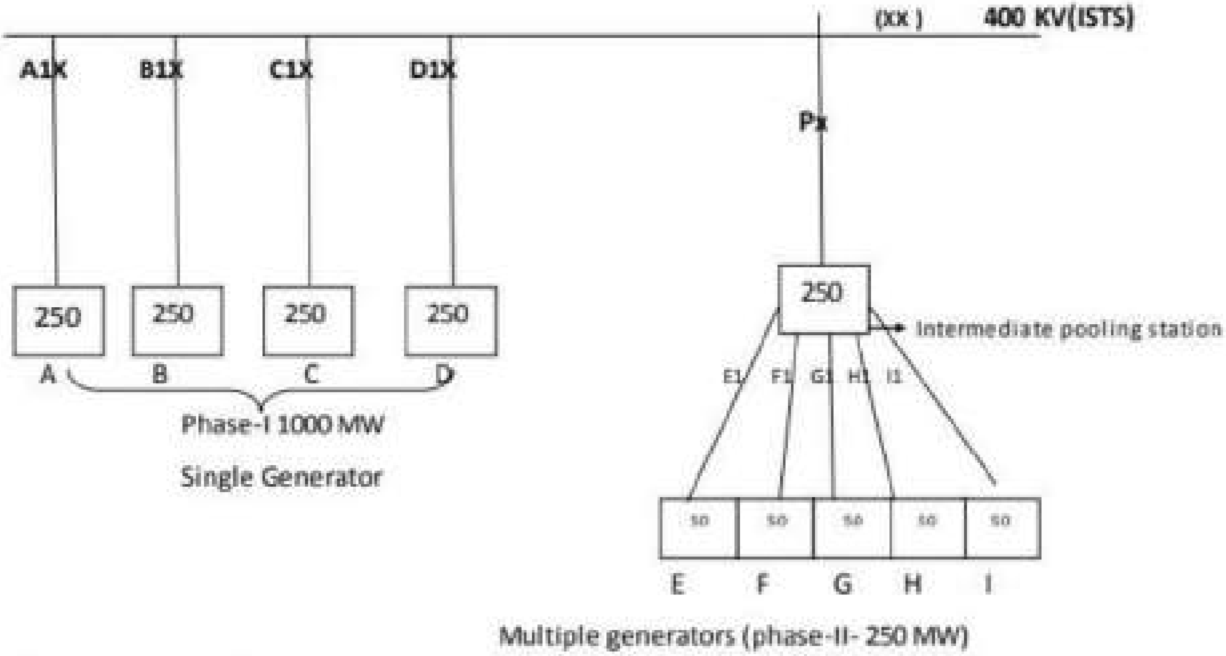


B. QCA responsible for some REGS connected at Intermediate pooling station




In each of the above scenarios, the QCA shall be responsible for coordination of scheduling and de-pooling of DSM charges for all those REGS that mutually agreed to appoint a QCA. The other REGS shall be required to submit their schedule as well as be liable to pay their DSM charges.

**Case-3: 50 MW and above (Phase-I &II)**




Phase-I – 1000 MW,

A single generator of 1000 MW capacity is developing the generating station in phase-1 in four blocks namely A,B,C & D of 250 MW capacity each and is directly connected to point A1,B1,C1& D1 respectively at ISTS. At the interface point scheduling and forecasting shall be done by RLDC.

**Phase-II- 500 MW (Separate Generator/Entities)**

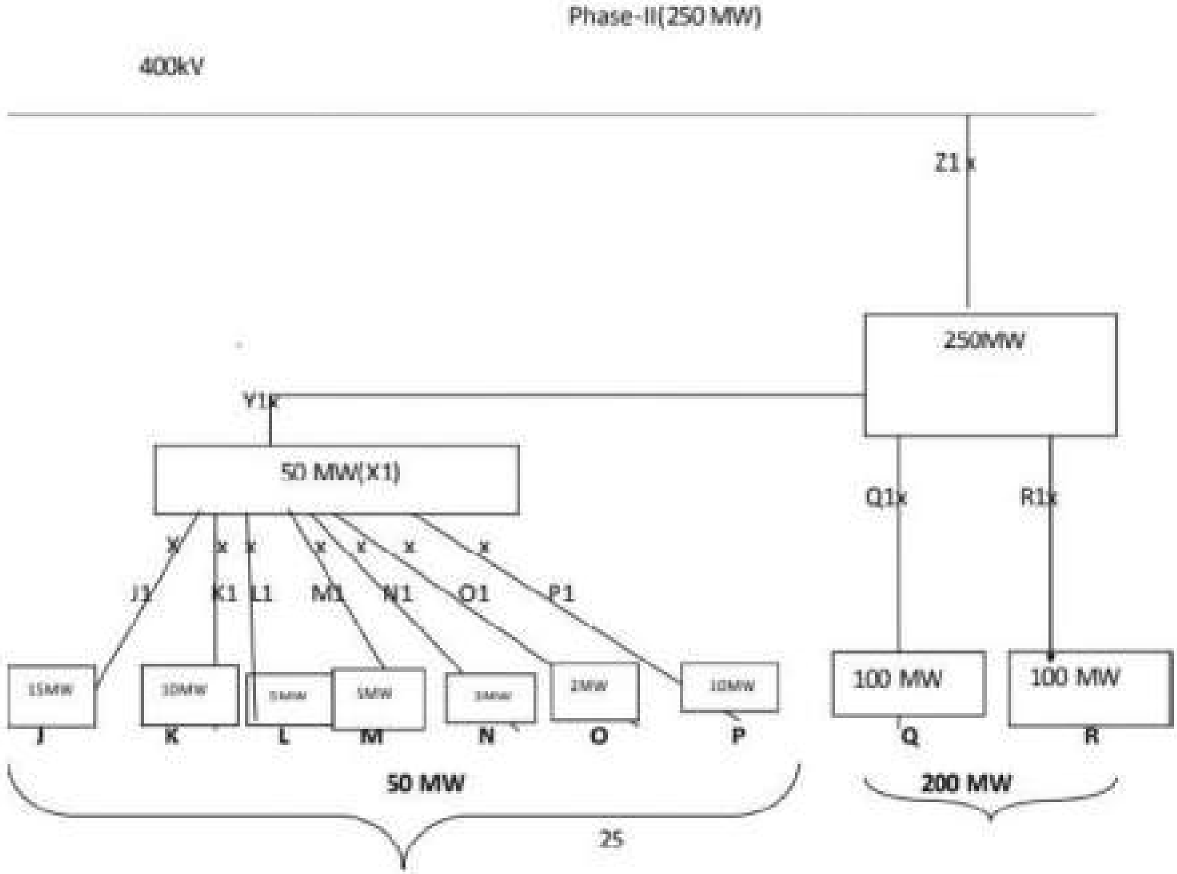
(a) Let multiple REGS of 50 MW each aggregating to 250 MW (5 Nos. Multiple Generator of 50 Mw each (as separate entities), be connected to inter mediate pooling stations.

(b) REGS namely E, F, G, H & I each having the capacity of 50 MW each are connected to interface point E1, F1,G1, H1& I1 and thereby connected to ISTS at XX point.

(c) In such a case, scheduling, accounting, forecasting for these generators needs to be segregated at point E1,F1,G1, H1, I1. Scheduling shall be done at point P and shall be segregated at E1,F1,G1,H1,I1 by RLDC.

(d) Further there may be case where multiple generators less than 50MW (<50MW) capacity are connected to theintermediate pooling station are stated as under:-

**Case-IIBelow 50 MW**




(e) Let us consider, multiple REGS (namely J,K,L,M,N,O&P ) collectively having an aggregate installed capacity of 50 MW or more and are represented through a Lead Generator. Further REGS Q & R each of 100MW are connected at Q1 & R1. All these REGS are connected to ISTS at point Z1.

(f) Scheduling and forecasting for the REGSs J,K,L,M,N,O& P shall be done at Point Z1, but need to segregated at Point J1, K1,L1, M1, N1,O1& P1 and for REGSs Q & R needs to be segregated at Q1 and R1. In this case,RLDC shall schedule at point Z1 and segregate at Y1,Q1& R1 . The lead generator shall provide aggregated schedule to RLDC at Y1. Further the lead generator shall do segregation of schedules and other operational & commercial activities for generators J,K,L,M,N,O,P at points J1, K1,L1, M1, N1,O1& P1.

## APPENDIX -M: ACCOUNTING AND POOL SETTLEMENT SYSTEM

**REFER TO:**
**CHAPTER 16: Transmission Metering Code**

(1) METERING, ACCOUNTING AND SETTLEMENT SYSTEM:

a) At the Intra State Transmission System (InSTS) 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 SLDC issuing the Accounts specifying the quantum of energy scheduled. All deviations from the schedule are settled through a State Deviation and Ancillary Services Pool Account maintained by SLDC 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 the Pool Account shall be in accordance with various regulations of the Commission. SLDC shall standardize the formats of various accounts.

c) The Implemented Schedule incorporating all before-the-fact changes in schedule shall be used as a reference for energy accounting.

d) Energy Accounts inter-alia shall indicate Declared Capability of generating stations, Entitlements, Requisitions, Scheduled loss, Scheduled transactions and actual Interchange, Reactive Power Accounts and any other accounts to be issued under AERC Regulations.

e) Assumptions, if any, in the accounts shall be clearly stated in Notes to the Accounts.

f) Each state entity (whether generator, RE Generator, QCA (on behalf of generators), captive Power Plant, OA customer) in a region shall be a member of the state pool and separately accountable for deviations. For cross border transactions, the settlement shall be as per CERC Regulations.

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Assam Electricity Regulatory Commission.

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