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Part VI—Section 2

Notifications of interest to a section of the public issued by Heads of Departments, etc.

NOTIFICATIONS BY HEADS OF DEPARTMENTS, ETC.

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NOTIFICATIONS BY HEADS OF DEPARTMENTS, ETC.

TAMIL NADU ELECTRICITY REGULATORY COMMISSION, CHENNAI

Tamil Nadu Electricity Grid Code, 2026

(Notification No. TNERC/GC/01 /2026), Dated: 13-02-2026)

(Lr.No. TNERC/Legal/1369/D.No. 216/2026)

No. VI(2)/13/2026.

In exercise of the powers conferred by Sections 86(1)(h) of the Electricity Act, 2003 (Central Act 36 of 2003) and all other powers enabling it in this behalf, the Tamil Nadu Electricity Regulatory Commission hereby makes the Tamil Nadu Electricity Grid Code, 2026 duly repealing the existing Tamil Nadu Electricity Grid Code, 2005 and the draft of the same having been previously published, as required under sub-section (3) of section 181 of the Act.

Chapter 1 – Short title and Commencement

1.1. Short Title, Commencement and Extent

(a) This Code may be called “Tamil Nadu Electricity Grid Code, 2026”

(b) The provisions of this Code shall come into force from the date of publication in the *Tamil Nadu Government Gazette.*

(c) This Code shall apply to State Load Despatch Centre (SLDC) of Tamil Nadu, every user who is connected to and/uses intra-state transmission system of the State Transmission Utility (STU) and intra-State Transmission Licensees and the users (Generators & OA consumers) connected with the Distribution System of the Distribution Licensee.

(d) These Regulations shall also be applicable to new connections and equipment procured/provided for new works / replacements from the date, this Code is made effective.

1.2. Scope

(a) Tamil Nadu Electricity Grid Code (TNEGC) is a document that defines the boundary between STU and Users and establishes the procedures for operation of facilities connected to the State Transmission System.

(b) The Grid Code shall be complied with by the STU in its capacity as the holder of the State Transmission Licence and by State Sector Generating Stations (SSGS), IPPs, State Transmission Licensees other than STU, Distribution Licensees, Open Access customers and any Other User of Intra-State Transmission System and Distribution System, in the course of generation, transmission and distribution of electricity.

CHAPTER 2 - Preliminary

2.1. Glossary and Definitions

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
1	Act	The Electricity Act 2003 (Central Act No. 36 of 2003).
2	Agency	Means an entity used in this Code to refer to a Licensee / Generating Station that utilize the Intra State Transmission System.
3	Alert State	means the state in which the operational parameters of the power system are within their respective operational limits, but a single n-1 contingency leads to violation of system security.
4	Ancillary Services	shall have the same meaning as defined in the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022 and amendments thereof.
5	Apparatus	means Electrical apparatus and includes all machines, fittings, accessories and appliances in which conductors are used.
6	Appendix	An Appendix to a chapter of the Grid Code.
7	Area Control Error (ACE)	shall have the same meaning as defined in the IEGC, 2023 and amendments thereof.
8	Area of Supply	means area designated in the license for carrying out the licensed activity.

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
9	Automatic Generation Control (AGC)	means a mechanism that automatically adjusts the generation of a control area to maintain its interchange schedule plus its share of frequency response.
10	Automatic Voltage Regulator (AVR)	means a continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals.
11	Auxiliary Energy Consumption	shall have the same meaning as defined in TNERC (Terms and Conditions for the determination of Tariff) Regulations and amendments thereof.
12	Available Capacity	shall have the same meaning as defined in TNERC's Deviation Settlement Mechanism Regulations issued in the year 2019 and 2024 and amendments thereof.
13	Available Transfer Capability (ATC)	means the transfer capability of the inter-control area transmission system available for scheduling commercial transactions (through long-term open 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.
14	Backing Down	means reduction of generation from generating unit under abnormal conditions such as high frequency, low system demand or network constraints under instructions from SLDC/ SRLDC.
15	Beneficiary	means a person who has a share in a Generating Station.
16	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 month.
17	Black Start	means a process of recovery from total or partial blackout of the State Transmission System.
18	Blackout	means a condition at a specific time where a part or all the operations of the power system have got suspended.
19	Breakdown	means an occurrence relating to equipment/Transmission /Distribution facilities of supply system which prevents its normal functioning.
20	Bulk Consumer	shall have the same meaning as defined in CEA Technical Standards for Connectivity and amendments thereof.
21	Buyer	means a person purchasing electricity through a transaction scheduled through intra-State transmission system in accordance with this Grid Code.
22	Capacitor	means an electrical facility provided for generation of reactive power.
23	Captive Generating Plant (CGP)	shall have the same meaning as defined in the Act.
24	CBIP	Central Board of Irrigation and Power.
25	CEA	Central Electricity Authority.
26	CEA Grid Standards	means the Central Electricity Authority (Grid Standards) Regulations, 2010 as amended from time to time
27	CEA Technical Standards for Communication	means the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020 as amended from time to time
28	CEA Technical Standards for Connectivity	means the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 as amended from time to time

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
29	CEA Technical Standards for Construction	means the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 as amended from time to time
30	Central Generating (CGS) Station	shall mean generating stations owned by the companies owned or controlled by the Central Government.
31	Central Transmission Utility (CTU)	shall mean utility notified by the Government of India under sub-section (1) of Section 38 of the Act
32	Centralised Data Collection Centre (CDCC)	means the centre which is responsible to collect, collate and process the energy meter data for various applications like energy accounting and auditing, energy billing, transmission system loss calculations and power purchase bill reconciliation.
33	CERC	Central Electricity Regulatory Commission
34	Code	Means Tamil Nadu Electricity Grid Code, 2026 inasmuch as this Code is concerned.
35	Co-generation	means a process, which simultaneously produces two or more forms of useful energy (including electricity).
36	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).
37	Collective Transaction	shall have the same meaning as assigned to it in Central Electricity Regulatory Commission (Power Market) Regulations, 2021 and amendments thereof.
38	Commission/ TNERC	shall mean Tamil Nadu Electricity Regulatory Commission.
39	Congestion	means a situation where the demand for transmission capacity or power flow on any transmission corridor exceeds its Available Transfer Capability.
40	Connection	means the electric lines and electrical equipments used for connecting the User's system to the Intra-State Transmission System.
41	Connection Agreement	means an agreement setting out the terms relating to the Connection to and / or use of the Intra-State Transmission / Distribution System.
42	Connection Conditions	means 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 this Grid Code and Procedure issued in this regard by the Commission.
43	Connection point	means a point at which a user's or Transmission Licensee's Plant and/or Apparatus connects to the Intra-State Transmission/ Distribution System.
44	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 prevailing Regulations/Grid Code/ Procedure issued in this regard by the Commission.
45	Connectivity Agreement	means an agreement between CTU/STU and any other person(s) setting out the terms and conditions relating to connection to and/or use of the Intra-State Transmission System in terms of prevailing Regulations/ Grid Code/Procedure issued in this regard by the Commission.
46	Constituent	means any agency who is a member of the State Electricity System
47	Consumer	shall have the same meaning as defined in the Act.
48	Control Area	means an electrical system bounded by inter-connections (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 this Grid Code.

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
49	Control Centre	includes NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOMs LDC/SCADA Centre whichever applicable, including main and backup Centres, as applicable.
50	Data Acquisition System (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.
51	Date of Commercial Operation (COD)	shall have the same meaning as specified in this Grid Code.
52	Declared Capacity (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 the Grid Code.
53	Demand	The demand in MW and MVA of electricity (i.e. both Active and reactive power).
54	Demand Response	means variation in electricity usage by the end consumers or by a control area manually or automatically, on stand-alone or aggregated basis, in response to system requirements as identified by the concerned LDC.
55	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.
56	Deviation	Deviation in a time-block for a seller means its total actual injection minus its total scheduled generation and for a buyer means its total actual drawal minus its total scheduled drawal;
57	Deviation Charges	shall have the same meaning as defined in the Commission's Deviation Settlement Mechanism Regulations and amendments thereof issued from time to time.
58	Deviation Settlement Mechanism (DSM) Regulations	shall have the same meaning as defined in the TNERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 and TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024 and amendments thereof issued from time to time.
59	Disconnection	means the act of physically separating electrical equipments of a User or EHV Consumer from the State Transmission System.
60	Distribution Licensee/ Distribution Company/DISCOMs	means a Licensee authorised by the Commission to operate and maintain a distribution system for supplying electricity to the consumers in his area of supply.
61	Distribution System	means the system of electric lines and electrical equipment at voltage levels of 33 kV and lower, including part of a State Transmission System, used for supply of electricity to a single consumer or group of consumers.
62	Disturbance Recorder (DR)	means a device provided to record the behaviour of the pre-selected digital and analog values of the system parameters during an Event.
63	Drawal	means the algebraic sum of import and export of electrical energy and power both active and reactive from the Regional Grid. In respect of DISCOMs, drawal means algebraic sum of import and export of electrical energy and power both active and reactive from STU.
64	Drawee Entity	means a consumer or a distribution licensee who has been connected with the intra-state transmission/distribution system.
65	EHV or Extra High Voltage	Nominal voltage levels of 66 kV and above.
66	EHV Consumer	means a person to whom electricity is provided and who has a dedicated supply at 66 kV or above.

Sl. No.	Defined Term	Definition
(1)	(2)	(3)
67	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.
68	Energy Storage System (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.
69	Entitlement	means the share of a DISCOMs (in MW and MWh) in the installed Capacity / output Capability of a Generating Station.
70	Event	means an unscheduled or unplanned occurrence in the grid including faults, incidents and breakdowns.
71	Event Logging	means a device for recording the chronological sequence of operations of the relays and other equipment.
72	Ex-Power Plant	means net MW or MWh output of a generating station, after deducting auxiliary consumption and transformation losses.
73	External interconnection	Electric lines and electrical equipment used for transmission of electricity between the Inter-State and Intra-State Transmission System.
74	Fault Locator (FL)	means a device installed at the end of a transmission line to measure or indicate the distance at which a line fault may have occurred.
75	Flexible Alternating Current Transmission System (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.
76	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.
77	Free Governor Mode of Operation (FGMO)	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.
78	Frequency Response Characteristics (FRC)	means automatic, sustained change in the power consumption by load or output of the generators that occurs 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, FRC = Change in Power (ΔP) / Change in Frequency (Δf).
79	Frequency Response Obligation (FRO)	means the minimum frequency response a control area has to provide in the event of any frequency deviation.
80	Frequency Response Performance (FRP)	means the ratio of actual frequency response with frequency response obligation.
81	Gaming	means an intentional/deliberate mis-declaration of declared capacity by any seller in order to make an undue commercial gain through charge for Deviations.
82	Generating Company	shall have the same meaning as defined in sub- section (28) of Section 2 of the Act.
83	Generating Station	shall have the same meaning as defined in sub- section (30) of Section 2 of the Act.

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
84	Generating Unit	means a) a unit of a generating station (other than those covered in sub-clauses (b) and (c) of this clause) having electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator; b) an inverter along with associated photovoltaic modules and other equipment in respect of generating station based on solar photo voltaic technology; c) a wind turbine generator with associated equipment, in respect of generating station based on wind energy; d) in respect of Renewable Hybrid Generating Station (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.
85	Generator	means a person or agency who generates electricity and who is subjected to Grid Code either pursuant to any agreement with STU or otherwise.
86	Good utility practices	Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period which could have been expected to accomplish the desired results at a reasonable cost consistent with good business practices, reliably, safely and with expedition.
87	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.
88	Grid Code Review Committee (GCRC)	means the Committee set up under Chapter-5 (Management of the Grid Code) of this Grid Code.
89	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.
90	Grid Disturbance (GD)	means the situation where disintegration and collapse of grid either in part or full takes place in an unplanned and abrupt manner, affecting the power supply in a large area of the region.
91	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.
92	High Voltage (HV)	means the voltage higher than 650 volts but not exceeding 33,000 volts under normal conditions.
93	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).
94	HVDC	High Voltage Direct Current System.
95	IEC	International Electro Technical Commission, the authority that approves the electricity industry standards used on an international basis
96	Independent Power Producer (IPP)	means a generating company not owned or controlled by Central / State Government/ their joint venture and such generating company is not classified as a Captive Generating Plant (CGP).

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
97	Indian Electricity Grid Code (IEGC)	Means regulations framed by Central Electricity Regulatory Commission under clause (h) of sub-section (1) of Section 79 read with clause (g) of sub-section (2) of Section 178 of the Act.
98	Indian Standard (IS)	means the standard established and published by the Bureau of Indian Standards (BIS) and subsequent updations.
99	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.
100	Infirm Power	shall have the same meaning as defined in TNERC – The Power Procurement from New and Renewable Sources of Energy Regulations, 2008 and amendments thereof.
101	Inter-State Transmission System (ISTS)	shall have the same meaning as defined in sub- section (36) of Section 2 of the Act
102	Inter Connecting Transformer (ICT)	means the transformer connecting EHV lines of different voltage levels.
103	Inter-State Generating Station (ISGS)	means a central generating station or any other generating station having a scheme for generation and sale of electricity in more than one State.
104	Intra-State Transmission System (InSTS)	shall have the same meaning as defined in sub- section (37) of Section 2 of the Act.
105	LDC	means Load Despatch Centre
106	Lean Periods	Means periods in a day when electrical demand is at its lowest
107	Licensee	shall have the same meaning as defined in the Act.
108	Load	means the active, reactive or apparent power consumed by a utility/ installation of consumer.
109	Load Crash	means 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.
110	Maximum Continuous Rating (MCR)	means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters.
111	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.
112	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 Regulations and amendments thereof.
113	Nadir Frequency	means the minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss.
114	National Grid	The entire inter-connected electric power network of the country, which would evolve after inter-connection of regional Grids.
115	National Load Despatch Centre (NLDC)	means the centre established under sub-section (1) of Section 26 of the Act.
116	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

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
117	Net Drawal Schedule at Intra-State level	means the drawal schedule of a State entity, which is the algebraic sum of all its transactions through the intra-State transmission system at Intra-State Transmission System periphery after deducting the transmission losses
118	Normal State	means the state in which the operational parameters of the power system are within their respective operational limits and equipment are within their respective loading limits.
119	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.
120	Operation	A scheduled or planned action relating to the operation of the power system.
121	Open Access	shall have the same meaning as defined in TNERC (Grid Connectivity and Intra-State Open Access) Regulations, 2014 and amendments thereof.
122	Open Access Customer (OAC)	shall have the same meaning as defined in TNERC (Grid Connectivity and Intra-State Open Access) Regulations, 2014 and amendments thereof.
123	Operating range	means the operating range of frequency and voltage as specified in Chapter-12 of this Grid Code.
124	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.
125	Outage	In relation to a Generator/ Transmission/ Distribution facility, means 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.
126	Peak Period	means that period in a day when electrical demand is at its highest.
127	Permit to Work (PTW)	means the 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.
128	Planned Outage	means an outage in relation to a SSGS unit or Power Station Equipment or Transmission facility, which has been planned and agreed with SLDC, in advance in respect of the year in which it is to be taken.
129	Pool Account	shall have the same meaning as defined in TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024 and TNERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 amendments thereof.
130	Pooling Station	shall have the same meaning as defined in TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024 and amendments thereof.
131	Power System	shall have the same meaning as defined in sub- section (50) of Section 2 of the Act
132	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.
133	Qualified Coordinating Agency (QCA)	shall have the same meaning as defined in TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024 and amendments thereof.

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
134	Ramp Rate	means rate of change of a generating station output expressed in % MW per minute.
135	Rate of Change of Frequency (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.
136	Reference contingency	means the maximum positive power deviation occurring instantaneously between generation and demand and considered for estimation of reserves.
137	Regional Grid	means the important elements of constituent / user systems including the ISTS which the RLDC supervises.
138	Regional Load Despatch Centre (RLDC)	means the Centre established under sub-section (1) of Section 27 of the Act.
139	Regional Power Committee (RPC)	shall have the same meaning as defined in the Act.
140	Renewable Energy Generating Station (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.
141	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.
142	Restorative State	means a condition in which control action is being taken to reconnect the system elements and to restore system load.
143	Renewable Hybrid Generating Station (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.
144	Rotational Load Shedding	means the planned disconnection of consumers on a rotational basis during periods when there is a significant shortfall of power required to meet the total demand.
145	Secondary Reserve	means the maximum quantum of power, which can be activated through secondary control signal by which injection or drawal or consumption of a Secondary Reserve Ancillary Service provider is adjusted in accordance with CERC (Ancillary Services) Regulations, 2022 and amendments thereof.
146	Seller	means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with the appropriate Regulations.
147	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.
148	Single Line Diagram (SLD)	means Diagrams which are a schematic representation of the HV/ EHV apparatus and the connections to all external circuits at a Connection Point incorporating its numbering nomenclature and labelling.
149	Site Common Drawing	Drawing prepared for each connection point which incorporates layout drawings, electrical layout drawings, common protection/control drawings and common service drawings
150	Southern Region / Region	means region comprising States and Union Territory of Tamil Nadu, Andhra Pradesh, Kerala, Karnataka, Telangana and Pondichery for the integrated operation of the electricity system.
151	SRLDC	means Southern Regional Load Despatch Centre.
152	SRPC	means Southern Regional Power Committee.
153	State	means the State of Tamil Nadu.

Sl. No.	*Defined Term*	*Definition*
(1)	*(2)*	*(3)*
154	State Entity	means such person who is in the SLDC control area and whose metering and energy accounting is done at the State level.
155	State Load Despatch Centre (SLDC) State Sub Load Centre (SSLDC)	means the load despatch centre established under section 31 (1) the Act, operating round the clock for the purpose of managing the operation of the transmission system and co-ordination of generation and drawal on a real time basis. means State's Sub Load Centre for local control at various places in Tamil Nadu
156	State Power Committee	means Committee set up under TNERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 and TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024.
157	State Sector Generating Station (SSGS)	Means power station within the, except Inter-State Generating Stations (ISGS) and Independent Power Producer generating stations (IPPs)/ Captive Generating Plant (CGP)/REGS located within the State of Tamil Nadu in which State has its share.
158	State Transmission System (STS)	means the system of EHV electric lines (66 kV and above voltage level) and electrical equipment operated and/or maintained by STU or any Transmission Licensee for the purpose of transmission of electricity between Power Stations, External Inter-connections, Distribution Systems and other users connected to it.
159	State Transmission Utility (STU)	means the Board or Government Company specified as such by the State Government under sub-section (1) of section 39 of the Act.
160	Static VAR Compensator (SVC)	An electrical facility designed for the purpose of generating or absorbing reactive power.
161	Sub-LDC	means the Load Despatch Centres set up at Chennai, Madurai and Erode or other places of Tamil Nadu.
162	Supervisory Control and Data Acquisition (SCADA)	means the combination of transducers, RTU, communication links and data processing systems, which provides information to SLDC on the operational state of the State Transmission System.
163	Synchronised	means the condition where an incoming Generating Unit or System is connected to another System so that the voltage, frequencies and phase relationships of that Generating Unit or System, as the case may be, and the System to which it is connected are identical and the terms "Synchronise" and "Synchronisation" shall be construed accordingly.
164	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.
165	Supply	"Supply" in relation to electricity, means the sale of electricity to a licensee or consumer.
166	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.
167	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 0:00 Hours, presently of fifteen (15) minutes duration.
168	TANTRANSCO	means Tamil Nadu Transmission Corporation Limited
169	TNGECL	means Tamil Nadu Green Energy Corporation Limited.
170	TNPDCL	means Tamil Nadu Power Distribution Corporation Limited.
171	TNPGCL	means Tamil Nadu Power Generation Corporation Limited.

Sl. No.	Defined Term	Definition
(1)	(2)	(3)
172	Total Transfer Capability (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.
173	Transmission Licence	means the Licence granted to Transmission Utility by the Commission under Section 14 of the Act.
174	Transmission Planning Criteria	means the criteria issued by CEA for transmission system planning.
175	Transmission Reliability Margin (TRM)	means the amount of margin earmarked in the total transfer capability to ensure that the inter-connected transmission network is secure under a reasonable range of uncertainties in system conditions.
176	Transmission Service Agreement (TSA)	means the agreement, contract, memorandum of understanding, or any such covenants, entered into between the transmission Licensee and the user of the transmission service/line.
177	Transmission System	The system of EHT electric lines and electrical equipment owned and / or operated by the STU and other transmission licensees, for the purpose of the transmission of electricity between power stations, external interconnections and the distribution system.
178	Trial Operation or Trial Run	shall have the same meaning as specified in this Grid Code, as applicable.
179	User	means and includes generating company, captive generating plant, energy storage system, Transmission Licensee including deemed Transmission Licensee, Distribution Licensee including deemed 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 of 33 kV and above and open access customer who uses the State Transmission System and who must comply with the provisions of the Grid Code.
180	Utility	"Utility" means the electrical lines or electrical plant and includes all lands, buildings, works and materials attached thereto belonging to any person acting as a generating company or licensee under the provisions of the Act.
181	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.
182	WS Seller	means a seller in case of a generating station based on wind or solar or hybrid of wind-solar resources.

Note:-

(1) Words and expressions used in this Grid Code, that are not defined herein but defined in the Act or other Regulations of the Commission shall have the meaning as assigned to them under the Act or the said Regulations of the Commission.

(2) Reference to any Acts, Rules and Regulations shall include amendments or consolidation or re-enactment thereof.

(3) In case of discrepancy between the Tamil and English version of this Grid Code, the English version shall prevail. The Commission's decision shall be final and binding in any dispute arising in this regard.

Chapter 3 - General

3.1. Objectives: The objective of this Code is to define the services rendered by each wing in the overall electric system and also for identifying the responsibilities and performance factors and measurement points for each one of them. Further, it facilitates intra-state transmission and Open Access of electricity, with a focus on the operation, maintenance, development and planning of the Tamil Nadu State Electricity Grid. This Code brings out a single set of technical requirements encompassing all the Generators, Licensees, and State Transmission Utility connected to or related to or using the Intra State Transmission System and provides the following:

a. To provide clarity and certainty to STU, Distribution Licensee(s), Generating Companies operating within the State of Tamil Nadu and any Open Access customers connected to Intra-State Transmission System/ distribution system by stating their respective roles, responsibilities and obligations.

b. The documentation of the principles and procedures, which define the relationship between various users of the Intra State Transmission System and State Load Despatch Centre as well.

c. Responsibilities and obligation with respect to the operation of the State Transmission System (STS)

d. Suitable measures for connectivity with the Grid for all generating plants.

e. The standards with reference to quality, continuity and reliability of service for compliance by the Licensees.

f. Planning of the State Electricity Grid and making arrangements for its operation, maintenance, development and expansion.

g. Operation of Grid under normal, abnormal and emergency conditions.

h. To indicate how generation is to be scheduled and despatched.

i. Procedures for black start, fast restart, restoration of supply after major disturbances.

j. Penalty for the non-compliance of this Grid Code, Grid Standards and the lawful directions of SRLDC and SLDC.

k. Facilitation for beneficial trading of electricity by defining a common basis of operation of the Intra State Transmission System and Distribution System applicable to all the users of the system.

l. To ensure economy and efficiency in the operation of the power system in the State.

m. To achieve compliance with the Grid Standards and other relevant Standards, Codes, Regulations and directions of SLDC by every licensee and others involved in the operation of the power system.

3.2. Structure of the Tamil Nadu Electricity Grid Code:

The Code is structured in distinct chapters as follows:

a) Functional responsibilities of entities connected with the State Grid

b) Management of Grid Code and various Committees

c) Resource Adequacy and System Planning

d) Grid Connectivity conditions

e) Requirement in Grid Operation

f) Scheduling and Despatch

g) Commercial issues and Implementation

h) Non Compliance

i) Metering

j) Cyber Security

k) Data Registration

3.3. General Requirements: The Grid Code contains procedures to permit equitable management of day to day technical situations in the Electricity Supply System, taking into account a wide range of operational situations and requirements likely to be encountered under both normal and abnormal conditions. It is nevertheless necessary to recognize that the Grid Code cannot predict and address all possible operational situations. Users must therefore understand and accept that, in such unforeseen circumstances, the State Load Despatch Centre (SLDC) / State Transmission Utility (STU) who has to play a key role in the implementation of the Grid Code may be required to act decisively for maintaining the Grid regimes for discharging its obligations. Users shall provide such reasonable co-operation and assistance as the SLDC / STU may request in such circumstances.

3.4. Application of other Codes etc.,

(a) Notwithstanding anything contained herein in the matters concerning intra-state transmission, the provision of IEGC shall prevail, in case of inconsistency between the IEGC and this Code.

(b) This code shall be read along with the Tamil Nadu Electricity Supply Code, Tamil Nadu Electricity Distribution Code, Open Access Regulations, Regulations on Deviation Settlement Mechanism and other relevant provisions of the Act, along with amendments thereon, rules and regulations made thereunder.

(c) Where any of the provisions of this Code is found to be inconsistent with those of the Act, rules or regulations made there under, notwithstanding such inconsistency, the remaining provisions of this Code shall remain operative.

(d) Where any dispute arises as to the application or interpretation of any provisions of this Code, it shall be referred to the Commission whose decision shall be final and binding on the parties concerned.

(e) Wherever extracts of the Electricity Act, 2003, are reproduced, any changes / amendments to the original Act shall automatically be deemed to be effective under this Code also.

3.5. Code Responsibilities

(a) In discharging its duties under the Grid Code, STU has to rely on information provided by Users / SLDC / SSLDC regarding their requirements and intentions.

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

3.6. Confidentiality

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

(b) STU/SLDC 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.

3.7. Dispute Settlement Procedures

(a) 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 on all the parties.

(b) 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 shall prevail.

3.8. Communication between STU and Users

(a) All communications between STU and Users shall be in accordance with the provision of the relevant chapter of the Grid Code and shall be made with the designated nodal officer, appointed by STU.

(b) Unless otherwise specifically required by the Grid Code, all communications shall be in writing, save where operational timescales require oral communication. Such oral communications shall be confirmed in writing as soon as practicable.

(c) The voice shall be recorded at SLDC and such record shall be preserved for a reasonable time.

Chapter 4 -Functional Responsibilities of entities connected with the State Grid

4.1. State Transmission Utility

(a) Responsible to undertake transmission of electricity through Intra State Transmission System.

(b) STU shall discharge all functions of planning and coordination relating to intra state transmission system with

i. Central transmission utility

ii. State Government

iii. Generating Stations

iv. Regional Power Committee

v. Central Electricity Authority

vi. All Licensees

vii. Any other person notified by the State Government in this behalf

(c) Ensure development of an efficient, coordinated and economical system of Intra-state transmission lines for smooth flow of electricity from a generating station to the load centers. All the planning works, viz., long term as well as short term shall be the responsibility of STU only.

(d) Provide non-discriminatory open access to its transmission system for use by

i. any licensee or generating company on payment of the transmission charges or;

ii. any consumer as and when open access is provided by the Commission under subsection(2) of section 42 of the Act, on payment of the transmission charges and a surcharge thereon as may be specified by the commission.

iii. be a nodal agency for all long term / medium term open access customers (except when both injection and drawal points are in distribution system).

(e) The STU shall ensure the power evacuation of the generating stations, for supply to the entities engaged in distributing electricity and to OA consumers, exchange of power among entities, exchange of power through inter-connection with CTU.

(f) STU shall be responsible for managing and enforcing the State Grid Code.

(g) STU shall not engage in the business of trading of electricity.

(h) The STU shall also hold meetings with the Users to discuss individual requirements and with the group of Users for preparing proposals for SPC meeting.

4.2. State Load Despatch Centre (SLDC)

(a) The SLDC shall exercise the powers and discharge the functions as prescribed under sub section (1) of section 31 of the Act. The SLDC shall be operated by a Government Company, or any Authority or Corporation established by the State Government, until such company, or Authority, or Corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre. The SLDC shall be the apex body to ensure integrated operation of the power system in a State. The SLDC shall:

i. be responsible for optimum scheduling and despatch of electricity within the State, in accordance with the contracts entered into with the licensees or the generating companies operating in the State.

ii. monitor Grid operation on real time;

iii. keep accounts of the quantity of electricity transmitted through the State Grid and responsible for data arrangement to help in decision making;

iv. exercise supervision and control over the intra state transmission system and operation of power plants;

v. be responsible for carrying out real time operations for Grid control and despatch electricity within the State through secure and economic operation of the State Grid in accordance with the Grid standards and this Code.

vi. not engage in the business of trading in Electricity.

vii. Certification of Availability of Intra-State Generating Stations and Intra-State Transmission Systems as and when requested by the utilities.

(b) The SLDC may levy and collect such fee and charges from the generating companies and licensees engaged in intra state transmission of electricity as may be specified by the commission.

(c) SLDC may give such directions and exercise such supervision and control as may be required for ensuring the integrated Grid operation and for achieving the maximum economy and efficiency in the operation of the power system. Every licensee, generating company, generating station, substation and any other person connected with the operation of the power system shall comply with the direction issued by the SLDC.

(d) State Load Despatch Centre shall discharge the functions assigned to it under the provisions of the Act and Grid Code in an independent and unbiased manner.

Provided that in event of a State Load Despatch Centre being operated by the State Transmission Utility, as per first proviso of sub-section (2) of Section 31 of the Act, adequate autonomy shall be provided to the State Load Despatch Centre to discharge its functions in accordance with the provisions of Tamil Nadu Electricity Grid Code.

(e) The monitoring agency for users shall be the SLDC. The monitoring agency shall track the progress of compliances of users, and exceptional reporting for non-compliance shall be submitted to the Commission periodically.

4.3. Transmission Licensees

Every Transmission Licensee shall comply with such technical standards of operation and maintenance of transmission lines, in accordance with this Code, Grid Standards, as may be specified by the Authority and the Indian Electricity Grid Code as applicable to the Intra State Transmission System. It shall be the duty of the transmission licensee

i. to maintain and operate the transmission system which are licensed to him in the intra state transmission system and comply with the directions of SRLDC and SLDC as the case may be

ii. provide non-discriminatory open access to its transmission system for use by any licensee or generating company or other users on payment of the charges as determined by the Commission.

4.4. Tamil Nadu Electricity Regulatory Commission (TNERC)

The functions of TNERC with relevance to TNEGC are:

i. To determine the rate, charges and terms for the use of the transmission facilities of Licensees and for other statutory purposes and requirements;

ii. To specify the fees and charges payable to SLDC;

iii. To issue directions on matters of non-compliance of TNEGC or to take decisions on any dispute referred to them;

iv. To issue transmission licenses;

v. To adopt the transmission tariffs for the transmission assets determined through Tariff-Based Competitive Bidding (TBCB) and Transmission asset monetization in line with the Commission’s Order / Regulations, MoP’s guidelines, etc. issued from time to time.

vi. To issue amendments to the TNEGC as and when required.

4.5. Government of Tamil Nadu (GoTN)

Government may issue directions to SLDC, to take measures as may be necessary for maintaining smooth and stable transmission and supply of electricity. SLDC shall abide by such directions if they are consistent with the provisions of the Act and this Code.

4.6. State Power Committee (SPC)

The following are the primary responsibilities of SPC:

i. SPC shall issue guidelines for implementation of TNEGC.

ii. Facilitating the implementation of the rules and procedures developed under the provisions of TNEGC.

iii. Assessing and recommending the 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 TNEGC.

iv. To undertake regular review of TNEGC and to make suitable recommendations after considering the Users’ suggestions.

v. To undertake State level operation analysis for improving grid performance

vi. To facilitate Intra-State transmission of power.

vii. To facilitate all functions of planning relating to Intra-State transmission system with STU.

viii. To undertake operational planning studies including protection studies for stable operation of the grid.

ix. To maintain a centralised database and update the same on a periodic basis containing details of protection relay setting for various grid elements.

x. Review the cyber security provisions in the grid.

xi. To analyse major Grid Disturbances, soon after the occurrence, and to suggest remedial measures and issue suitable directives to the Users.

xii. To approve load shedding guidelines through under frequency relays.

xiii. In case of open access power and duties as defined in Tamil Nadu Electricity Regulatory Commission (Grid Connectivity and Intra State Open Access) Regulations, 2014, as amended from time to time.

xiv. Duties assigned under TNERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 and TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024.

xv. Any other function as may be directed by the Commission from time to time.

Chapter 5 – Management of State Grid Code

5.1. Management of Grid Code and various Committees

(a) STU is required to implement and comply with the Grid Code and periodically review the same and its implementation. For the above purpose, a Grid Code Review Committee as per **Regulation 5.4** of the Grid Code, shall be established.

(b) All revisions in the Grid Code shall be proposed by majority votes in the meeting of Grid Code Review Committee. In the event of equality of votes on proposal, the matter shall be referred to the Commission for decision. All revision in the Grid Code made by the Grid Code Review Committee shall also be submitted to the Commission for approval.

(c) The changes/revisions proposed by the Grid Code Review Committee shall be consistent/ compatible with IEGC and amendments thereof. The Commission may issue directives requiring STU to submit proposal for revision in the Grid Code and STU shall forthwith comply with such directives within timelines contained therein. STU shall be responsible for managing and enforcing the State Grid Code. STU shall establish and service the requirements of the Grid Code Review Committee in accordance with the provisions of **Regulation 5.4** of the Grid Code.

5.2. Grid Code Review Committee

(a) The Commission shall approve the constitution of Grid Code Review Committee through separate order on receipt of proposal from the SLDC within 30 days from the date of issue of this Code.

(b) STU shall inform all Users in writing, the name and address of the Chairman and Members of the Grid Code Review Committee within fifteen (15) days of the constitution of the Grid Code Review Committee and any subsequent changes thereafter.

(c) The Committee, containing of not more than 12 members, shall inter-alia include members from the various types of generating stations, Transmission Licensee, STU, SLDC and Distribution Licensee.

5.3. Grid Code Review Committee Proceedings

(a) Member Secretary of the Grid Code Review Committee shall be responsible for arranging the meetings in a timely manner. The procedure to be followed by the Committee in conducting its business shall be formulated by the Committee and shall be approved by the Commission. The Committee shall meet at least once in a year.

(b) The functions of the Grid Code Review Committee are as follows:

i. To keep the Grid Code and its implementation under scrutiny and review.

ii. To propose any revision, if necessary, in the Grid Code consequent of analysis report on major grid disturbance soon after its occurrence. The recommendations of the Committee may be submitted to Commission for approval and issuing directives to the Users for taking necessary remedial measures, as may be deemed fit, to prevent recurrence.

iii. To consider all requests for amendment to the Grid Code, which any User makes and take action as per this Code, if found appropriate after consideration.

iv. To issue guidance on the interpretation and implementation of the Grid Code.

v. To examine problems/ issues raised by Users.

(c) STU may schedule a meeting with a User or group of Users to discuss the issues in implementation of this Grid Code and prepare proposals for the Grid Code Review Committee meeting.

(d) If the Committee considers it necessary to discuss any special issue with the Commission, the Committee may send an appropriate proposal to the Commission along with a copy of Minutes of Meeting (MoM) wherein the issue was identified. The Commission may take up the issue for consideration in a manner as deemed fit by the Commission.

5.4. Grid Code Review and Revisions

(i) Any written request seeking review/modification/amendment of the Grid Code shall be sent to STU. If the request is sent directly to the Commission, the same shall be forwarded to STU.

(ii) The Member Secretary of the Committee shall present all proposals for revision of the Grid Code before the Grid Code Review Committee for its consideration.

(iii) Member Secretary of the Committee shall send to the Commission, the following reports at the conclusion of each review meeting of the Committee:

i. A report on the outcome of such review meeting;

ii. Any proposed revisions to the Grid Code as STU reasonably thinks necessary for the achievement of the objectives of this Code;

iii. All written representations or objections from Users arising during the review/consultation process.

(iv) All revisions in the Grid Code shall be made by the Commission.

(v) STU shall convey to all the Users, revisions in the Grid Code after amendment by the Commission.

(vi) STU shall make available a copy of the respective parts of Grid Code in force to any person requesting it on payment of cost thereof.

(vii) The Commission shall reserve the right to review the Grid Code as and when required.

5.5. Functional Committees

(a) The STU shall be responsible for implementation of Grid Code whereas, the Grid Code Review Committee shall be responsible for management of Grid Code and for proposing any changes or modifications in the Grid Code. The STU shall submit the proposal before the Commission for constitution of the following functional committees and other committees as deemed fit for implementation of the Grid Code within a month of the publication of this Code:

a)	Load Despatch & System Operation Code	Operation and Co-ordination Committee (OCC)
b)	Protection Code	Protection Co-ordination Committee (PCC)
c)	Transmission Metering Code	Transmission Metering Committee (TMC)

(b) The Commission shall approve the constitution of Functional Committees through separate order.

(c) The SLDC in coordination with the above committees and stakeholders consultation shall frame the Codes for Load Despatch & system operation, Protection and Transmission metering within 30 days from the date of appointment of the Committee concerned and the same shall be submitted within seven days to the Commission for approval. The Codes shall be consistent with the TNEGC/IEGC/CEA (Installation & Operation of meters) Regulations, 2019 as amended from time to time.

5.6. Operation and Co-ordination Committee (OCC)

(a) Operation and Co-ordination Committee (OCC) shall deliberate on all technical and operational aspects of this Grid Code except Protection and Metering Code.

(b) The Committee shall meet at least once in two months.

(c) The procedure to be followed by the Operation and Co-ordination Committee in conducting their business shall be formulated by the respective Committee and shall be approved by the Grid Code Review Committee.

(d) Operation and Co-ordination Committee (OCC) shall conduct the following functions:

i. Review of existing inter-connection and equipment for alteration, if necessary, so as to comply with the Connection Code.

ii. Deliberation on connectivity criterion for voltage imbalance as specified in the Commission's Regulations and amendments thereof and taking remedial measures for cases failing to meet such criterion.

iii. Review the load management through under frequency, time differential (df/dt) relays and Advanced Distribution Management System (ADMS) etc.

iv. Transmission system planning coordination for the State as a whole.

v. Issues related to energy accounting and scheduling of intra-State energy.

vi. To discuss and resolve issues pertaining to availability of real time data through Supervisory Control and Data Acquisition (SCADA).

vii. Review the voice communication facility among SLDC and Users.

viii. Review and analyse the grid disturbances and system restoration procedure.

ix. Review and finalize Outage Plan of State Transmission System.

x. Review the installation of Disturbance Recorders, Event Loggers in the State Transmission System.

xi. Review and study the implementation of free governing / restricted governing mode for all eligible generating stations.

xii. Review the Licensee's sub-station equipment failure and replacement of the same within the stipulated timeframe

xiii. Review the adequacy of manpower for operation and maintenance of the Sub-Station, Lines, etc.

xiv. Any other matter related to technical and operational parameters.

5.7. Protection Co-ordination Committee (PCC)

(a) Protection Co-ordination Committee (PCC) shall ensure implementation of Protection Code by the Users and discharge their obligations under the Protection Code.

(b) The Committee shall meet at least once in three (3) months.

(c) The procedure to be followed by the Protection Co-ordination Committee in conducting their business shall be formulated by the respective Committee and shall be approved by the Grid Code Review Committee. Protection Co-ordination Committee (PCC) shall conduct the following functions:

i. To keep Protection Code and its implementation under scrutiny and review.

ii. To consider all the requests for amendment to the Protection Code made by users.

iii. To issue guidance on the interpretation and implementation of the Protection Code

iv. Any other matter related to coordination amongst Users in relation to protection and relays.

5.8. Transmission Metering Committee (TMC)

(a) Transmission Metering Committee (TMC) shall ensure implementation of metering system by the Users and discharge their obligations as per the CEA Metering Regulations and the amendments issued from time to time and the Commission's Regulations/Codes/Orders.

(b) The Committee shall meet at least once in three (3) months.

(c) The procedure to be followed by the Transmission Metering Committee in conducting their business shall be formulated by the respective Committee and shall be approved by the Grid Code Review Committee. Transmission Metering Committee (TMC) shall conduct the following functions:

i. To keep Metering system and its working under scrutiny and review.

ii. To consider all the requests for change/modification to the Metering system, which any user makes.

iii. To issue guidance on the interpretation and implementation of the CEA Metering Regulations and the amendments issued from time to time and the Commission's Regulations/Codes/Orders.

iv. Review the installation of interface meters already installed at the Generator end and give corrective steps/suggestive measures in line with the CEA Regulations.

v. Any other matter related to coordination amongst Users in relation to metering.

5.9. Monitoring of Compliance

(a) State Transmission Utility and State Load Despatch Centre shall be responsible for monitoring the compliance of Users and State Transmission Licensees with the provisions, contained in the Tamil Nadu 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.

(b) If any User fails to comply with any of the provision(s) of the Grid Code, it shall be required to inform STU without any delay, the reason for its non-compliance and shall remove its non- compliance promptly.

(c) 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, non-payment of charges such as Deviation settlement charges, scheduling and system operation charges, Open Access charges, etc. shall constitute non-compliance of Grid Code and shall be subject to financial penalty as may be decided by the Commission.

(d) 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.

(e) 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.

(f) 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.

(g) 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 the Tamil Nadu 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.

(h) If any Transmission Licensee or any User fails to comply with the directions issued under the Grid Code, he shall be liable to penalty not exceeding Rs. five (5) Lakh.

(i) The Commission may order independent third-party compliance audit for any User, as deemed necessary based on the facts brought to the knowledge of the Commission.

Chapter 6 - Resource Adequacy and System Planning

6.1. Resource Adequacy

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 environmental 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.

6.2. Integrated Resource Planning

The integrated resource planning shall include:

(a) Demand forecasting;

(b) Generation resource adequacy planning; and

(c) Transmission resource adequacy planning.

6.3. Demand Forecasting and Generation Resource Adequacy Planning

(a) The provisions related to demand assessment and forecasting and Generation Resource Adequacy Planning shall be governed by the provisions of the Guidelines for Resource Adequacy Planning Framework for India, 2022 published by the CEA as amended from time to time, TNERC (Framework for Resource Adequacy) Regulations,2025 and Regulations/Orders/direction notified/issued by the Commission for Demand Forecasting and Generation Resource Planning.

(b) In order to ensure optimum and least cost generation resource procurement planning, each distribution licensee of the State or any agency on its behalf 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.

6.4. Transmission resource adequacy planning

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

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

(ii) Adequate power transfer capability across the Intra-State Transmission System.

(b) The STU shall be responsible for overall planning of STS and shall prepare a perspective rolling transmission system plan for –

(i) Short term period *i.e.* up to 5 years;

(ii) Medium term period *i.e.* up to 10 years;

(iii) Long term period *i.e.* up to 15 years.

Provided that the transmission system plans shall be updated every year to accommodate the revisions in the load projections and generation capacity additions:

Provided further that State Transmission Utility shall publish on its website the short term transmission system plans along with updations, if any for STS, by 30th September for each year. The STU shall publish its current ongoing InSTS plan in its website.

Provided also that such transmission system plans shall also make available to any person upon request.

6.5. System Planning

(a) The System Planning 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 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.

(b) 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.

(c) In accordance with Section 39(2)(d) of the Act, STU shall inter-alia provide non-discriminatory open access to its transmission system for use by:

i. any Licensee or generating company on payment of the transmission charges; or

ii. 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.

(d) In accordance with Section 40(c) of the Act, the Transmission Licensee shall inter-alia provide non-discriminatory open access to its transmission system for use by:

i. any Licensee or generating company on payment of the transmission charges; or

ii. 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.

(e) 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.

(f) 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.

(g) The System Planning Code provides the following:

i. 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.

ii. 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.

iii. Details the information required by STU from Users to enable STU to plan the development of its Transmission System to facilitate proposed User developments.

iv. Specifies planning and design standards, which will be applied by STU in planning and development of the power system.

6.6. Planning Policy

(a) 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.

(b) 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.

(c) 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 Distribution Licensees.

(ii) STU shall prepare a transmission plan for the State Transmission System compatible with this Regulation 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 SRLDC/SRPC/SLDC/Distribution Licensees for installation of reactive compensation equipments.

(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.

(d) All the Users shall supply to STU, the desired planning data by 31stMay every year to enable STU to formulate and finalise the plan by 30thSeptember each year for the next five (5) years.

6.7. Planning Responsibility

(a) The primary responsibility of demand forecasting within Distribution Licensees' area of supply rests with the Distribution Licensees. The 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 31stMay 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.

(b) 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 March to STU.

(c) STU shall obtain Renewable Capacity Addition plan issued by the Tamil Nadu Green Energy Corporation.

(d) The Distribution Licensee 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.

(e) The planning for strengthening the State Transmission System for evacuation of power from outside State stations shall be initiated by STU.

(f) Operation and Co-ordination Committee consisting of members from Distribution Licensee, STU, Transmission Licensee, Tamil Nadu Green Energy Corporation and Tamil Nadu Power Generation Corporation shall review and approve the demand forecasts and the methodology.

6.8. Planning Data

(a) 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:

i. Standard Planning Data (Generation)/ Standard Planning Data (Distribution) **(Appendix-A)**

ii. Detailed Planning Data (Generation)/ Detailed Planning Data (Distribution) **(Appendix-B)**

(b) 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:

i. Standard Planning Data (Transmission) **(Appendix-A)**

ii. Detailed Planning Data (Transmission) **(Appendix-B)**

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

6.9. Implementation of Transmission Plan

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

Chapter 7 – Grid Connectivity Conditions

7.1. Objective

The objective of this chapter is to ensure the following:

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

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

(c) 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.

(d) 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.

7.2. Grid Connectivity

(a) This 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 Intra-State Transmission System (InSTS).

(b) The connectivity to Intra-State Transmission System shall be granted by State Transmission Utility in accordance with the Grid Code, Tamil Nadu Electricity Regulatory Commission (Grid Connectivity and Intra State Open Access) Regulations, 2014 and other Regulations/Codes/Orders/Procedures issued by the Commission from to time.

(c) The applicant who seeks connectivity with the Transmission system shall apply as per the Format approved by the Commission in the detailed procedure for grant of connectivity to the intra-state transmission system issued in accordance with the TNERC (Grid connectivity and Intra-State Open Access) Regulations, 2014. The applicant shall apply for grid connectivity along with the enclosures as prescribed in the format including final clearance / sanction from TNGECL/TNPDCL/TNPGCL and a compliance report for the generation project.

(d) STU and Users connected to or seeking connection to State Transmission System (STS) shall comply with the following Act/Regulations and amendments issued from time to time:

i. The Electricity Act, 2003 and amendments thereof;

ii. Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 and amendments thereof;

iii. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and amendments thereof;

iv. Central Electricity Authority (Grid Standards) Regulations, 2010 and amendments thereof;

v. Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020 and amendments thereof;

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

vii. Tamil Nadu Electricity Regulatory Commission (Grid Connectivity and Intra State Open Access) Regulations, 2014 and amendments thereof;

viii. Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and amendments thereof;

ix. Central Electricity Authority (Measures Relating to Safety & Electric Supply) Regulations, 2023 and amendments thereof;

x. Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 and amendments thereof;

xi. All relevant Laws/Regulations/Guidelines/Rules/Standards with amendments as specified from time to time shall be applicable for grant of connectivity.

(e) This Code shall be applicable to generators (including CGPs/Renewable Energy Generating Stations (REGS)), Energy Storage Systems, Distribution Licensees, Captive Users, Open Access Customers, Intra-State Transmission Licensees, HT/EHT Consumers of Distribution Companies and all other Users of Intra-State Transmission System. HT/EHT consumers seeking to avail power from State Distribution Companies shall however route their application for connectivity through concerned Distribution Licensee.

(f) This Code shall apply to applications 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.

(g) The existing Users, already connected to the Intra-State Transmission System prior to issuance of this Code shall not be required to make a 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 HT/EHT consumer of Distribution Licensee connected at voltage 33 kV and above and the HT/EHT consumers of the Distribution Licensee desiring connectivity to higher voltage will be required to make fresh application for connectivity.

(h) 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.

(i) The procedure for obtaining connectivity to the intra-state transmission system and distribution system shall be as per the detailed procedures issued by the Commission in this regard under Tamil Nadu Electricity Regulatory Commission (Grid Connectivity and Intra State Open Access) Regulations, 2014.

7.3. Responsibilities for operational safety

(a) STU and Users shall be responsible for safety as indicated in Regulation 7 (Site Responsibility Schedule) of CEA Technical Standards for Connectivity Regulations and amendment thereof.

(b) The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules shall be formulated by STU and shall be provided to each User for compliance.

7.4. Single Line Diagrams

(a) 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.

(b) Whenever any equipment is 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.

(c) 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.

7.5. Site Common Drawings

(a) Site Common Drawing shall 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.

(b) 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.

(c) 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.

7.6. System Performance

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

(b) 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.

(c) 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.

(d) 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.

(e) State Generating Stations and IPPs (including CGPs) 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. CGPs shall similarly furnish the net reactive capability that will be available for Export to/Import from Intra-State Transmission System.

(f) The frequency shall always remain within the band as specified in IEGC.

(g) The User shall however, be subject to the grid discipline of SLDC/SRLDC as per guidelines mutually agreed with SRPC/SRLDC.

(h) The variation of voltage at the “inter-connection point” may not be more than the limit specified in Regulation 12.6 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 the TNE Supply Code.

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

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

(j) 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.

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

7.7. Equipment of Users/ State Transmission System at Connection Points

(a) 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.

(b) Fault Clearance Time (basic step operation time, i.e., Zone 1 time):

(i) 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.

(ii) 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.

(iii) 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.

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

(c) Generating Units and Power Stations

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 12** of this Grid Code, subject to the design limitations specified by the manufacturer. A generating unit shall be provided with protection as specified in the Protection Code, which condition shall be made a part of the Connection Agreement.

(d) Reactive Power Compensation

Reactive Power compensation and/or other facilities should be provided by User of the State Transmission System including the Distribution Licensee as far as possible close to the load points thereby avoiding the need for exchange of Reactive Power to/from Intra-State Transmission System and to maintain voltage within the specified range. Switched Shunt Reactors at 400 kV may be provided to control temporary over-voltage within the limits and this shall be made a part of the Connection Agreement. The addition of reactive compensation to be provided by the User shall be indicated by STU in the Connection Agreement for implementation.

(e) Communication Facilities

(i) 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.

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

(iii) All Users shall provide the required facilities at their respective ends and SLDC and this condition shall be indicated in the Connection Agreement.

(iv) 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.

(v) 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.

(vi) 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.

(vii) If real time communication facility and data are not made available by the generators, the SLDC after 15 days clear notice shall direct the Distribution Licensee to exclude the generator’s output by 10% from Despatch and deviation settlement processes and if such generator has not made real time communication facility even after the lapse of 30 days from the date of receipt of the notice issued by the SLDC, the entire output of the generator shall be excluded from despatch and deviation settlement processes. If the generator has not made real time communication facility even after the lapse of 45 days from the date of receipt of the notice issued by the SLDC, further action will be taken by the SLDC as per the provisions of CEA Regulations duly informing the Commission.

(f) 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.

(g) 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.

(h) Schedule of assets of State Transmission Grid

STU shall submit annually to the Commission by 30th September each year a schedule of transmission assets, which constitute the State Grid, i.e., State Transmission System as on 31st March of that year indicating ownership on which SLDC has operational control and responsibility.

(i) Connection Point

(i) State Sector Generating Station (SSGS) Voltage may be 765/400/230/110/66 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 metering system shall comply with the Transmission Metering Code; provided that, until the notification and enforcement thereof, the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2019, as amended from time to time, shall apply. 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.

(j) Connectivity point & Voltage level in respect of Distribution Licensee:

The connectivity point of Distribution Licensee shall be on the LV side of the power transformer, i.e., 33 kV or 22 kV or 11 kV or as agreed with STU. For EHV consumer directly connected to transmission system, voltage may be 400 kV or 230 kV or 110 kV or 66 kV.

(i) The Connection point shall be the outgoing feeder gantry/cable termination on transmission tower/pole at respective Intra-State Transmission Licensee sub-station. Intra-State Transmission Licensee/Distribution Licensee shall maintain all the terminals, communication and protection for the metering system as per the Metering Code.

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

Note: The Distribution Licensee shall, within thirty (30) days from the date of notification of this Grid Code, constitute a Distribution Metering Committee and formulate the Distribution Metering Code in accordance with the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2019, as amended from time to time, and other applicable statutory provisions. The Distribution Metering Code so formulated shall be submitted to the Commission within seven days from the date of framing of Distribution Metering Code for approval prior to its implementation. The proviso clause specified under the regulation 7.7(i)(iii) shall also be applicable to this clause (j).

(k) IPPs, CGPs, EHV Consumers and Open Access Users

Voltage may be 400/230/110/33 kV or as agreed with STU. When sub-stations are owned by IPPs, CGPs, EHV Consumers or the Open access users, the Connection point shall be the outgoing feeder gantry on their premises.

(l) 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 11 kV or above and comply with the connectivity conditions as specified in CEA Technical Standards for Connectivity Regulations as amended.

(m) Commissioning of Connectivity

(i) The commissioning of all the new projects shall be governed as per Chapter 9 of this Grid Code.

(ii) 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, TNEGC and IEGC as amended from time to time.

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

(iv) Installation of meters, their 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.

(v) 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.

(vi) 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 and issue of unique charging code shall be issued by SLDC in consultation with STU and respective Intra-State Transmission Licensee. In line with the above, the SLDC shall prepare procedure for first time energization of new or modified power system elements to intra-State transmission system duly consulting the stakeholders and approval of such procedure shall be obtained from the Commission within 60 days. In the absence of such procedure of SLDC, the NLDC procedure shall apply for the elements of 230 kV and above.

(n) Post Connectivity Events

(i) The Post-connectivity events in relation to Generating Plant, Sub-station, Transmission Line of the applicant or Intra-State Transmission Licensees shall mean activities pertaining to interchange of power with Intra-State Transmission System, Operation & Maintenance of such Generating Plant/Sub-station/Transmission Line by Applicant or Intra-State Transmission Licensee, Operation & Maintenance of dedicated transmission line, Operation & Maintenance of evacuation system associated with plant generating non-firm power or any other activity as may be notified by STU.

(ii) Post connectivity events shall be undertaken in accordance with this Grid Code and relevant Regulations of CEA/Commission in general and specifically in respect of scheduling, despatch, energy accounting, DSM accounting and settlement of accounts for Open Access transactions. The aforesaid activities will be taken-up by SLDC in consultation with STU and Intra-State Transmission Licensees.

(o) Data Requirements

Users shall provide STU with data for this chapter as specified in the Data Registration Code chapter of this Grid Code. Unless otherwise agreed in Connection Agreement, the equipment for data transmission and communication shall be operated and maintained by User in whose premises they are installed, irrespective of ownership.

Chapter 8 – System Security Code

8.1. Introduction

This chapter describes the security aspects to be followed by Intra-State Transmission System Users for grid security and safety of electrical equipment.

8.2. Objective

The objective of this chapter is that, all Users shall endeavour to operate their respective power system and generating stations in synchronization with each other at all times, so that the whole State Transmission System operates as a synchronised system as well as an integrated part of the Southern Regional Grid. The STU shall endeavour to operate the inter-State links in such a way, that inter-State transfer of power can be achieved smoothly, whenever required. Security of the power system and safety of power equipment shall enjoy priority over economically optimal operations.

8.3. System Security Aspects

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

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

(c) No part of the State Transmission System shall be deliberately isolated from the integrated Grid, except:

(i) Under an emergency and conditions in which such isolation would prevent a total Grid collapse and/or enable early restoration of power supply;

(ii) When serious damage to costly equipment is imminent and such isolation would prevent it;

(iii) For safety of Human Life;

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

(v) On operation of under frequency/islanding scheme as approved by SRPC/SLDC.

(d) Any such isolation shall be reported to SLDC within the next fifteen (15) minutes. All such isolations shall be restored, as soon as the conditions again permit it. No transmission elements shall be synchronized without prior consent of SLDC/Sub-LDC. In case of any Grid incidence/disturbance, Grid shall be restored as per Detailed Operating Procedure of SLDC and instructions given by SLDC during real time operation. No User of the Grid is allowed to perform any switching operation by their own. The restoration process shall be supervised by SLDC.

(e) All operational instructions given by SRLDC and SLDC shall have unique codes, which shall be recorded and maintained as specified in CEA Grid Standards Regulations and amendments thereof. No transmission element shall be taken into service without obtaining unique code from the SLDC. All Generators including RE and ESS shall have to obtain unique code before synchronization with the State Grid or while isolating from the Intra-State Transmission System.

(f) SLDC, in consultation with SRPC, Users and the SRLDC, 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.

(g) An important element of the State Grid as listed at Regulation 8.3(f) of the Grid Code can be taken out of service only after prior clearance/ approval of SLDC, except in emergencies as per the Detailed Operating Procedure(s) of SLDC. SLDC shall inform the opening or removal of any such important element (s) of the State Grid to SRLDC/NLDC/SRPC and the concerned regional entities, who are likely to be affected, as specified in the Detailed Operating Procedure of NLDC or SRLDC or SLDC.

(h) 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, if the element is within the control area of SLDC, who in turn shall intimate the SRLDC. The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within half an hour. The SLDC and the Users shall ensure restoration of such elements within the estimated time of restoration, as intimated.

(i) 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 the SRLDC and NLDC in accordance with the system restoration procedures of NLDC or SRLDC or SLDC.

(j) 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 grid or sub-optimal operation of the grid shall be monitored by SLDC. SLDC shall report such outages to SRLDC/SRPC. SLDC shall also issue suitable instructions to restore such elements in a specified time period.

(k) 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.

(l) 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 in 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.

(m) Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the concerned SRPC/ 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.

(n) SLDC / SPC shall prepare the islanding schemes 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. All users shall ensure that installation and operation of the protection system shall comply with the provisions of CEA Grid Standards Regulations and amendments thereof.

(o) Mock drill of the islanding schemes shall be carried out annually by SLDC in coordination with SRLDC 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.

(p) 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 SRPC from time to time. The default UFR settings shall be as specified in Table below or as amended in IEGC from time to time:

Sl. No.	***Stage of UFR Operation***	***Frequency (Hz)***
1.	Stage-1	49.40
2.	Stage-2	49.20
3.	Stage-3	49.00
4.	Stage-4	48.80
Note-1: STU shall plan UFR settings and df/dt load shedding schemes depending on load generation balance in coordination with SLDC and approval of the SRPC.		
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 SRPC to Tamil Nadu.

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

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

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

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

(iv) 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 the SRLDC in real time and submit a monthly exception report to respective RPC. SLDC shall inform the SRLDC as well as SRPC on 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/respective RPC. SLDC shall take corrective measures within a reasonable period and inform the SRLDC and SRPC, failing which suitable action may be initiated by respective RPC.

(v) SRPC shall undertake a monthly review of UFR and df/dt scheme and may also carry out random inspection of the under-frequency relays. SRPC shall publish such a monthly review along with an exception report on its website.

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

(r) 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/flowgates. Any such SPS at the intra-regional level shall be finalized by the SLDC/SRPC. 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 SRLDC.

(s) 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
110	121	99
66	72	60
33	36	30

(t) SLDC shall take appropriate measures to control the voltage as per its operating procedures.

(u) The concerned Users shall implement defence mechanisms as finalized by the respective RPC/SLDC to prevent voltage collapse and cascade tripping.

(v) 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.

(w) All Users and SLDC shall take all possible measures to ensure that the grid frequency always remains within the specified band as specified in IEGC and amended thereof 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 100 (one hundred) MW without prior permission of the SLDC. Similarly, 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.

(x) Provision of protections and relay settings shall be coordinated with State Transmission System, as per plan finalised in Protection Co-ordination Committee.

(y) Each User shall provide adequate and reliable communication facility with SLDC to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes, e.g., User to SLDC.

(z) The Users shall send information/data including disturbance recorder/sequential event recorder output, etc., to SLDC for the purpose of analysis of any grid disturbance/event. No User shall block any data/information required by SLDC for maintaining reliability and security of the grid and for analysis of an event.

8.4. Special requirements for Solar/Wind generators

SLDC shall make all efforts to evacuate the available solar and wind power and treat them as a must-run station. However, SLDC may instruct the solar/wind generator to back down generation on consideration of grid security or if safety of any equipment or personnel is endangered, and Solar/Wind generator shall comply with the same as per the procedure issued by the Commission in this regard. For this, Data Acquisition System facility/ communication system shall be provided for transfer of information to SLDC:

(i) SLDC may direct a wind farm to curtail its Reactive Power drawal/injection in case, the security of grid or safety of any equipment or personnel is endangered.

(ii) During the wind generator start-up, the wind generator shall ensure that the reactive power drawal shall not affect the grid performance.

8.5. Management of RE Curtailment

All the entities concerned shall follow the detailed procedure for management of RE curtailment for wind and solar generation issued by the Commission in this regard.

Chapter 9 - Commissioning and Commercial Operation Code

9.1. Introduction

This chapter covers aspects related to drawal of start-up power 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.

9.2. Drawal of Start Up Power and Injection of Infirm Power

(a) 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 interchange 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.

(b) The period for which such inter-change shall be allowed shall be as follows: -

- 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
- 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).
- Injection of infirm power shall not exceed 45 days from the date of first time energisation and integration approval for REGS and ESS (except Hydro PSP ESS).

(c) Notwithstanding the provisions of the Regulation 9.2(b), the Commission may allow extension of the period for interchange 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 the SLDC on an application(s) made by such generating station or ESS (except Hydro PSP ESS) to the 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.

(d) Drawal of start-up power shall be as per the relevant Regulations/Orders of the Commission.

(e) The charges for deviation for drawal of start-up power or for injection of infirm power shall be governed by the relevant Deviation Settlement Regulations/Orders of the Commission.

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

(g) 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.

(h) 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.

(i) SLDC shall stop the drawal of the start-up Power in the following events:

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

(ii) In the case of default in payment of charges to the utilities, deviation settlement charges, etc.

9.3. Data to be furnished prior to notice of Trial Run

(a) The following details, as applicable, shall be furnished by each generating station entity 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
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

9.4. Notice of Trial Run

(a) 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.

(b) 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.

(c) 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.

(d) A generating station shall be required to undergo a trial run in accordance with the below mentioned Regulation 9.5 after completion of Renovation and Modernization for extension of the useful life of the project as per the Tariff Regulations.

9.5. Trial Run of Generating Unit

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

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

Provided that:

1. short interruption or load reduction shall be permissible with the corresponding increase in duration of the test;

2. 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;

3. cumulative interruption of more than four (4) hours shall call for a repeat of trial run.

(ii) 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.

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

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

Provided that -

1. short interruption or load reduction shall be permissible with a corresponding increase in duration of the test;

2. 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 the period of interruption but including the corresponding extended period;

3. cumulative interruption of more than four (4) hours shall call for a repeat of trial run;

4. 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 9.5(b)(ii) and such de-rating shall be effective from COD.

(ii) 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.

(c) Trial Run of Solar/ Wind/ ESS/ PSP/ Hybrid Generating Station:

(i) 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:

(ii) Successful trial run of a solar inverter unit(s) covered under the above Regulation 9.5(c)(i) 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:

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

(iv) 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 9.5(c)(ix).

(v) 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:

(vi) Successful trial run of a wind turbine(s) covered under the above Regulation 9.5(c)(v) 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 9.5(c)(x).

(vii) 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.

(viii) 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 9.5(b)(ii), such de-rating shall be effective from the COD.

(ix) 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.

(x) 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.

(xi) In the case of Wind/Solar/ESS/Hybrid Generating Station projects having installed capacity of 50 MW or more, the trial run may be performed in instalments, with a minimum capacity of 20% of the proposed capacity for each instalment.

(xii) 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.

(d) 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.

9.6. Documents and Tests Prior to Declaration of Commercial Operation

(a) 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.

(b) 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 telemetering 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.

9.7. 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.

9.8. 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.

9.9. 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.

9.10. 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 9.6 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.

(i) Failure of Generator to comply with the Low Voltage Ride through (LVRT) / High Voltage Ride through (HVRT) requirements as specified in 9.10(b) shall constitute a violation of Grid Security.

(ii) Upon detection and verification of such non-compliance, the State Load Despatch Centre (SLDC) shall issue a Notice to the concerned Generator, directing to take necessary corrective action and ensure compliance within a period of thirty (30) days from the date of receipt of such Notice.

(iii) In the event of failure or repeated non-compliance beyond the aforesaid notice period, the SLDC shall file a petition before the Commission within 15 days from the date of expiry of notice period for appropriate remedy for the Grid indiscipline caused by such wind and solar generators.

(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.

9.11. 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 9.18 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.

9.12. 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).

9.13. 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.

9.14. Certificate of Successful Trial Run

(a) 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.

(b) After completion of a successful trial run and receipt of documents and test reports as per this 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.

9.15. Declaration by Generating Company and Transmission Licensee

(a) Thermal Generating Station -

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 9.15(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 and to the Member Secretary of the concerned State Power Committee (SPC) before the declaration of COD.

9.16. 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 fire fighting 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 Instrumentation, 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 9.16(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 and to the Member Secretary of the concerned RPC before the declaration of COD.

9.17. 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.

9.18. 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.

9.19. Declaration of Commercial Operation and Commercial Operation Date (COD)

(a) 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:

(i) Thermal Generating Station or a unit thereof

1. 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 9.5(a)(ii) of the Grid Code, as the case may be, and submission of a declaration as per Regulation 9.15(a) of the Grid Code.

2. 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.

(ii) Hydro Generating Station

1. 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 9.5(b)(ii) of the Grid Code, as the case may be, and submission of a declaration as per Regulation 9.16 of the Grid Code.

2. 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.

(iii) Transmission System

1. 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 9.5(d) of the Grid Code and submission of a declaration as per Regulation 9.17 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 seeks commercial operation of 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.

2. 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 and Long-Term Transmission Customer (LTTC), the COD of the said transmission element may be declared prior to the declaration of the COD of its pre-required transmission elements.

(iv) 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.

(v) Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

1. 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 9.5(c) of the Grid Code, shall mean the date declared by the generating station after undergoing a successful trial run as per Regulation 9.5(c) of the Grid Code, submission of declaration as per Regulation 9.18 of the Grid Code, and subject to fulfilment of other conditions, if any, as per PPA.

2. 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.

(b) 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.

Chapter 10 – Operational Planning Code

10.1. Introduction

This chapter describes the process by which, SLDC shall carry out the operational planning and demand control procedures to permit reduction in demand for any reason.

10.2. Objective

The detailed provision is required to enable SLDC to achieve a reduction in demand to avoid operating problems on all or part of the State Transmission System. SLDC shall utilise Demand Control in a manner, which does not unduly discriminate against any one or group of customers.

10.3. Operating Philosophy

(a) 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

(b) Operation of the State grid shall be monitored by SLDC.

(c) Detailed Operating Procedures for State grid shall be developed, maintained and updated by the SLDC, consistent with the Detailed Operating Procedures of SRLDC.

(d) SLDC shall have qualified operating personnel manning the control room round the clock.

(e) Every generating station and transmission sub-station of 66 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.

(f) 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.

10.4. Demand Estimation

The demand estimation shall be done by the DISCOM(s)/STU in accordance with the provisions of the Grid Code and Resource Adequacy Regulations. SLDC/STU shall be provided with a copy of the same as and when it is finalized.

10.5. Demand Control

(a) Primarily the need for demand control would arise on account of the following conditions:

(i) Variations in demand from the estimated or forecasted values, which cannot be absorbed by the grid;

(ii) Unforeseen generation/ transmission outages resulting in reduced power availability; and

(iii) Heavy reactive power demand causing low voltages.

(b) SLDC shall match the consolidated demands of the DISCOM(s) 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.

(c) SLDC would maintain a historical database for the purpose of Demand Estimation and shall be equipped with the state-of-the-art tools such as Energy Management System (EMS) for short-term demand estimation to plan in advance, as to how the load would be met without overdrawing from the grid.

(d) SLDC shall advise STU for planning of automatic load shedding and rotational load shedding schemes through installation of Under Frequency Relays and df/dt relays.

(e) 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).

(f) Demand control can also be exercised by SLDC through direct circuit breaker tripping using RTUs or under frequency detection by SLDC SCADA or through telephonic instructions. Demand shed by operation of under frequency relays shall not be restored without specific directions from SLDC.

(g) Rotational load shedding schemes through installation of Under Frequency Relays and df/dt relays shall be prepared, in accordance with the instructions/guidelines issued by SRLDC/SRPC.

10.6. Demand Disconnection

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

(b) Distribution Licensees shall ensure that requisite load shedding is carried out in its control area, so that there is no over drawal.

(c) The SLDC through respective Distribution Licensees shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response etc., to reduce over drawal in order to comply with Regulation 10.6(a) and Regulation 10.6(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 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 SRLDC 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 over drawal/ 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.

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

10.7. Load Crash

(a) 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:

(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.

(b) While implementing the above, the system security aspects should not be violated as per relevant provisions under IEGC and State Grid Code.

Chapter 11 - Schedule and Despatch Code

11.1. 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.

11.2. 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 despatch/ drawal of generators and DISCOMs/Users respectively.

11.3. General Principles of Scheduling

(a) 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/buyer, the drawal schedule and to each SSGS and IPPs, CGPs, etc. the generation schedule in advance:

(b) Users shall submit the following documents before commencement of scheduling of power:

i) Documents in support of the connectivity and open access by Seller or Buyer, as applicable.

ii) Copies of valid contracts signed by Sellers and Buyers, for transactions other than collective transactions.

iii) Copy of allocation order, in case power is allocated by the State Government.

(c) 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.

(d) 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.

(e) 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 SRLDC, as the case may be, as existing before the date of coming into force of this Grid Code.

(f) The Generating Station(s) shall declare ex-bus Declared Capacity limited to 100% MCR less auxiliary power consumption on day ahead basis without fail. If any of the generating Station(s) fail to provide such schedule, the SLDC may issue notice to such generating Station(s) to comply with the scheduling procedure and if such generating Station(s) fail to do so, the SLDC shall file appropriate petition before the Commission and the Commission shall take decision on case to case basis.

(g) 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.

(h) The State Load Depatch 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.

(i) The SSGS, IPPs and any other thermal generating station shall be required to demonstrate the declared capability/capacity 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, the capacity charges due to the generator shall be reduced as a measure of penalty.

(j) The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days' fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression over a period of a month.

(k) DISCOM(s) will give their requisitions on day ahead/Real time basis to the SLDC and SLDC shall operate on real time basis as per individual Merit Order furnished by the DISCOM(s), i.e., in ascending order of the cost of energy (i.e., variable cost) of generating stations excluding hydro, nuclear and REGS.

Notwithstanding anything contained in the clause (k), in the absence of any requisition from the DISCOM(s), the SLDC shall operate on real time basis as per the Merit Order Despatch or as it deems fit and appropriate in the given circumstances based on the available data.

(l) The 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.

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

(n) 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 relevant Regulations/Orders issued by the Commission.

(o) 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) SLDC to check that schedules are operationally reasonable particularly in terms of Ramping up / Ramping down rates and ratio between minimum and maximum generation levels. SLDC to moderate the schedule to the required extent under intimation to concerned Distribution Licensees. The ramping up / ramping down rates in respect of different categories of stations would be as follows:

1. 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;

2. 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;

3. 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;

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

(p) 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.

(q) For calculating the net drawal schedule of DISCOMs, the transmission losses shall be apportioned in proportion to their drawal schedule.

(r) In addition to the above, the generators have to follow the provisions of the TNERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 and TNERC (Forecasting, Scheduling and Deviation Settlement and related matters for wind and solar generation) Regulations, 2024 and amendments thereof issued from time to time

[Note:- Commission *vide* Order No. 1-1 of 2024, dated 20-02-2024 has ordered that the Hydro Generating Stations including the Pumped storage power plant of the TNGECL (formerly TANGEDCO) are exempted under the purview of the Deviation Settlement Mechanism. This exemption for these power plants shall be continued until further orders from the Commission. However, these Generating Power Plants shall declare the Declared Capacity to the SLDC.]

11.4. 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:

(a) Forecasting demand for its control area for each time block on day-ahead and intra-day basis;

(b) Forecasting of generation from wind/solar generators, Hybrid of Wind and Solar Generating Stations and Energy Storage System (ESS) under its jurisdiction 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;

(c) Scheduling and despatch for the entities in the State control area in accordance with contracts;

(d) 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;

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

(f) Maintaining and despatching reserves as shall be decided by SRPC as per guidelines of central agencies;

(g) 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 SRLDC 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 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 66 kV and above for the preparation of scenarios for computation of TTC and ATC by SRLDC and NLDC. STU in co-ordination with Distribution Licensee(s) and generating stations shall submit this data to SLDC by 5th of M-12 month and may revise on M-6 (by 5th day) and M-1 (by 5th day) months. TTC and ATC calculations for the State shall be done based on procedure for the transfer capability assessment methodology published by NLDC.

11.5. Scheduling Process

(a) By 6 AM on 'D-1' day, each Intra-State SSGS/IPPs/CGPs/REGS/other generators connected with the intra-state transmission system 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 in the formats prescribed by SLDC. The Generating Stations shall submit the following information:

(i) Generating Station based on coal, gas and lignite:

1. Time block-wise On-bar Declared Capacity (MW) for on-bar units.
2. Time block-wise Off-bar Declared Capacity (MW) for off-bar units.
3. Time block-wise Ramp up rate (MW/ min) for on-bar capacity.
4. Time block-wise Ramp down rate (MW/min) for on-bar capacity.
5. MWh capability for the day.
6. Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar.

Note:- Declared Capacity shall be given as per unit wise/plant wise as requested by SLDC.

(ii) Generating Station based on hydro energy:

1. Time block-wise ex-bus declared capacity.
2. MWh capability for the day.
3. Ex-bus peaking capability in MW and MWh.
4. Time block-wise Ramp up rate (MW/min) for on-bar capacity.
5. Time block-wise Ramp down rate (MW/min) for on-bar capacity.
6. Unit-wise/plant-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity.
7. Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.
8. Unit-wise/plant-wise maximum MW along with probable combination of unit maximum in case adequate water is not available.

Note:- Declared Capacity shall be given as per unit wise/plant wise as requested by the SLDC.

(iii) 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/Pooling sub-station wise breakup of aggregate available capacity, schedules of the pooled generation shall also be furnished as per the Deviation Settlement Mechanism Regulations and the procedures issued by the Commission.

(iv) 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/ Pooling sub-station wise breakup of aggregate available capacity, schedules of the pooled generation shall also be furnished as per the Deviation Settlement Mechanism Regulations and the procedures issued by the Commission.

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

(b) 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.

(c) SRLDC shall declare share of each Beneficiary or Buyer for 0000 hours to 2400 hours of ‘D’ day, by 7 AM on ‘D-1’ day.

(d) 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 shall intimate the same to the Distribution Licensee(s) including Deemed Licensees by 07:15AM on ‘D-1’ day.

(e) By 07:45 AM of ‘D-1’ day, the Distribution Licensee(s) including Deemed Licensees will furnish requisition to SLDC in each ISGS, other agreements, Intra-State, SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of ‘D’ day.

(f) By 8 AM of ‘D-1’ day, SLDC shall convey the requisition of the State to SRLDC from ISGS/other agreements/SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of ‘D’ day.

(g) The SLDC on behalf of the intra-State entities while furnishing time block-wise requisition under this Grid Code, 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.

(h) SRLDC 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 by 8:15 AM on ‘D-1’ day.

(i) The Intra-State Entity shall revise their requisition for drawal schedule based on availability of transmission corridors by 8:30 AM on ‘D-1’ day.

(j) SRLDC shall issue initial drawal schedules and injection schedules for the State by 9 AM on ‘D-1’ day. SRLDC shall convey the generating station-wise drawal schedule of the State by 9:00 AM on ‘D-1’ day.

(k) The SLDC shall issue initial despatch/drawl schedules at 9.15 AM on ‘D-1’ day for the intra-state entities under SLDC purview.

(l) In case a generating station under the purview of SRLDC other than REGS intends to replace its schedule by power supplied from REGS, it shall intimate the quantum and source of power in the SRLDC/NLDC website by which it intends to replace the power already scheduled by 9:15 AM on ‘D-1’ day.

(m) SRLDC 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.

(n) SLDC shall issue modified depatch/drawl schedules at 10 AM on ‘D-1’ day for the intra-state entities under SLDC purview if there are any changes in the intra-state entities.

(o) SRLDC shall release the balance corridors after finalisation of schedules for day ahead collective transactions.

(p) Power Exchange(s) shall open bidding window for day ahead collective transactions from 10:00 AM to 11:00 AM of ‘D-1’ day. 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. 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.

(q) SRLDC shall release balance corridors after finalisation of schedules under day ahead collective transactions by 1:00 PM of ‘D-1’ day.

(r) SRLDC/ 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.

(s) SRLDC, 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 for exigency applications or in real time market on first-come-first-served basis.

(t) SLDC shall issue depatch/drawl schedules for State entities at 22:45 hours on 'D-1' day as final revision before real-time market operation.

(u) All the entities participating in the real-time market may place their bids and offers on the Power Exchange(s) for purchase and sale of power. 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. NLDC shall indicate to the Power Exchange(s) the available margin on each of the transmission corridors before the gate closure. 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.

(v) NLDC shall finalise schedules under real time market (RTM) by 23:30 hours of 'D-1' day and SRLDC, subsequently SLDC, shall publish the final schedules for depatch by 23:35 hours of 'D-1'day. Subsequently, the SLDC shall publish the schedules during intra-say operations.

(w) Scheduling process for the inter-state entities liable to change as per the IEGC and its relevant regulations. Subsequently, SLDC shall change the scheduling process by incorporating the changes in the inter-state entities whenever, there is change in scheduling timeline.

(x) 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 State Distribution Licensees including Deemed Licensees.

11.6. Rules for revision in schedule

(a) In the event of a situation arising due to bottleneck in evacuation of power due to transmission constraint in a block, SLDC shall revise the schedule, which shall become effective from the next time block.

(b) In case of any grid disturbance, the scheduled generation of all the generating stations and scheduled drawal shall be deemed to be equal to their actual generation/ drawal for all the time blocks affected by grid disturbance. The certificate of grid disturbance and its duration shall be declared by the SLDC or SRLDC and the same will be binding on all intra-State transmission system Users:

Provided that in case, SLDC observes that there is a need for revision of schedule in the interest of State Grid Security for better system operation and to facilitate integration of RE power into the grid, SLDC may do so on its own and in such cases, the revised schedule shall become effective from next time block.

(c) Revision of Declared Capacity and schedule shall be allowed on account of forced outage of a unit of an intra-State 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, schedule and the 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 a pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from 6th time block, counting the time block in which revision is advised by the generators to be the first one. The revised declared capacity shall be considered based on the ramp-up rate of the generating stations.

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), or ESS, may revise its estimated restoration time only once in a day.

Provided further that the SLDC shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective in the 6th time block from the estimated time of restoration of the unit.

Provided further that in case of inter-state transactions, the revision of schedule shall be carried out as per the provisions of the IEGC as amended from time to time.

(d) 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 may allow upward revision of DC beyond the above limit keeping in view of grid requirements.

(e) 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 may allow upward revision of DC beyond the above limit keeping in view grid requirements.

(f) 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 6th time block, counting the time block in which the revision is informed by WS seller to be the first one.

(g) In case of requirement of revision of Declared Capacity due to forecasting error, a Run-of-River 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 6^{th} time block, counting the time block in which the revision is informed to SLDC to be the first one.

(h) If a revision is received from any ISGS stations, RLDC will flash the information in real-time basis containing all the relevant information needed to revise the schedule based on which SLDC will process the revision in parallel. The implementation time of revision will be same for both RLDC and SLDC.

(i) SLDC, on behalf of intra-State drawee entities may revise their schedules, which shall become effective from 6th time block, counting the time block in which the revised schedule is issued by SLDC to be the first one:

Provided that scheduled transactions under short term open access once scheduled cannot be revised.

(j) After the operating day is over at 24:00 hours, the schedule finally implemented during the ‘D’ day (taking into account all before-the-fact changes in Despatch Schedule of Electricity Generating Stations and Drawal Schedule of the other Intra-State Entities) shall be issued by SLDC within three (3) days or on receipt of SRLDC implemented schedule. Further, the implemented schedule may be revised by SLDC, if Ex-post facto revision in implemented schedule is made by SRPC/TNSPC. These Schedules shall form the basis for commercial accounting. The average ex-bus capability for each SSGS and IPPs shall also be worked out based on all before-the-fact advice to SLDC.

(k) The SLDC shall prepare detailed procedure for the scheduling as per this grid code within 60 days of notification of these regulations duly consulting the stakeholders and submit it to the Commission for approval.

11.7. Scheduling from alternate source of power by a generating station

(a) A generating station may supply power from alternate source in case of 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.

(b) The methodology for scheduling of power from alternate sources covered under forced outage of unit(s) shall be as per the following steps:

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

(ii) 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 6th time block.

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

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

(v) 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.

(c) 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:

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

(ii) The generating station shall request SLDC to schedule power from such alternate source to its beneficiaries, which shall become effective from 6th time block.

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

(iv) 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.

(d) 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 the Commission's Regulations/Orders issued from time to time.

(e) 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.

11.8. Minimum Turndown Level for operation of Thermal Generating Stations

(a) The technical minimum level for operation in respect of thermal generating units connected to STU network and which is in the 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 determined under Section 62 or 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 specified in the applicable Tariff Regulations or to be specified by the Commission separately.

(b) The SSGS having 100% installed capacity tied up/contracted with DISCOM(s) of the State through long-term PPA and whose tariff is determined by the Commission, may be directed by SLDC to operate below normative plant availability factor but at or above technical minimum. In such cases, SSGS shall be compensated as per the provisions of the TNERC (Terms and conditions for determination of Tariff) (Amendment) Regulations, 2025 or other Regulations as notified by the Commission from time to time on monthly basis duly supported by relevant data verified by SLDC.

(i) In case the scheduled generation of the Coal/Lignite based generating stations falls below the technical minimum schedule, the concerned generating stations shall have the option to go for reserve shut down and in such cases, start-up fuel cost over and above seven (7) start/stop in a year shall be considered as additional compensation based on the provisions of the TNERC (Terms and conditions for determination of Tariff) (Amendment) Regulations, 2025 or other Regulations as notified by the Commission from time to time.

(ii) Compensation for Station Heat Rate and Auxiliary Energy Consumption shall be worked out in terms of energy charges.

(iii) The compensation so computed shall be borne by the entity who has caused the plant to be operated at schedule lower than corresponding to Normative Plant Availability Factor up to technical minimum based on the compensation mechanism finalized by SLDC, which shall be guided by the mechanism finalized by SRPC.

(iv) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible, if the actual Station Heat Rate and/ or actual Auxiliary Energy Consumption are lower than normative Station Heat Rate and / or normative Auxiliary Energy Consumption applicable to unit or generating station in a month or after annual reconciliation at the end of year.

(v) There shall be reconciliation of compensation at the end of financial year taking into due consideration of actual weighted average operational parameters of station heat rate, auxiliary energy consumption and secondary oil consumption.

(c) In case of generating stations other than SSGS, wherein the 100% installed capacity is not tied up with DISCOM(s) of the State or whose tariff for only partial/contracted capacity is determined by the Commission, such generating station may have to appropriately factor in the above provisions in their PPAs entered with DISCOM(s) for sale of power, in order to claim compensation for operating at the technical minimum schedule.

11.9. Data Registration

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

Chapter 12 - Frequency and Voltage Management Code

12.1. 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 EHV voltage of the State Transmission System.

State Transmission System normally operates in synchronism with the Southern Region Grid and SRLDC has the overall responsibility of the integrated operation of the Southern Regional Power System. The constituents of the Region are required to follow the instructions of SRLDC for backing down generation, regulating loads, MVAr drawal, etc., to meet the objective. SLDC shall accordingly instruct Generating Units to regulate generation/ export and hold reserves of active and reactive power within their respective declared parameters. SLDC shall also regulate the load as may be necessary to meet the objective.

12.2. 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/State Grid Code.

12.3. Frequency Management

(a) 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.

(b) **Falling frequency**

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

(c) **Rising Frequency**

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

12.4. Reserve

(a) There shall be reserves as under:

(i) Primary, Secondary and Tertiary reserves:

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

2. The response under Primary reserve shall be provided as per this Grid Code.

3. Secondary reserves including automatic generation control and demand response shall be deployed in the control area as may be notified by the Commission separately indicating the date from which such deployment of Secondary reserves shall be effective.

4. Tertiary reserves shall be deployed in the control area as may be notified by the Commission separately indicating the date from which such deployment of Tertiary reserves shall be effective.

(ii) Black Start reserves:

Generating stations having black start capability, ESS, and HVDC Station based on VSC, shall be identified by NLDC and RLDCs in consultation with SLDC at the inter-State level and by SLDC at the State level, to act as black start reserves.

(iii) 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.

(b) The mechanism of procurement and deployment of Primary Reserves Ancillary Service (PRAS) shall be as specified in this Grid Code or by separate order.

(c) The mechanism of procurement, deployment and payment of Secondary Reserve Ancillary Service and Tertiary Reserve Ancillary Service shall be as may be notified by the Commission.

(d) 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.

12.5. Control Hierarchy

(a) **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.

(b) **Primary Control**

(i) 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.

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

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

(iv) 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.

(v) NLDC in consultation with SLDC may also identify other resources such as ESS and demand resource to provide PRAS for which PRAS providers shall be compensated in accordance, as may be notified by the Commission.

(vi) 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, 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.

(vii) All the generating units shall have their governors or frequency controllers in operation all the time with droop settings 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 station more than 10 MW and connected at 33 kV and above	As per CEA Technical 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.

(viii) 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.

(ix) 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.

(x) All generating stations, including the WS Seller as mentioned in the 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 conditions 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.

(xi) 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.

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

(xiii) The Primary Reserves Ancillary Service (PRAS) shall start immediately when the frequency deviates beyond the dead band as specified in above Regulation 12.5(b)(x) and shall be capable of providing its full PRAS capacity obligation within 45 seconds and sustaining at least for the next five (5) minutes.

(xiv) Each control area shall assess its frequency response characteristics and share the assessment with the concerned SRLDC 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.

(xv) The SRLDC shall calculate actual frequency response characteristics of all the control areas within its region. The performance of each control area in providing frequency response characteristics shall be calculated for each reportable event as per IEGC.

(xvi) NLDC in consultation with RLDCs/SLDCs 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.

(xvii) NLDC, RLDC and SLDC shall grade the median Frequency Response Performance annually, considering at least ten (10) reportable events. In case the median Frequency Response Performance is less than 0.75 as calculated, NLDC, RLDCs, SLDCs, 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 concerned RPC for its review.

(c) Secondary Control and Tertiary Control shall be such as may be notified by the Commission separately.

12.6. Voltage Management

(a) 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 limits of voltage specified in IEGC are reproduced below:

Voltage (kV rms)		
Nominal	**Maximum**	**Minimum**
765	800	728
400	420	380
230*	245*	207*
110	121	99
33	36	30

** As per CEA Manual on Transmission Planning Criteria and updated thereof.*

(b) 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 DISCOM(s) to determine voltage level at the inter-connection points. SLDC shall continuously monitor 400/220/110 kV voltage levels at strategic sub-stations.

(c) SLDC 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 DISCOM(s) at 33kV 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.

(d) 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. CGPs shall similarly furnish the net reactive capability that will be available for Export to/ Import from State Transmission System.

(e) DISCOM(s) 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.

12.7. Reactive Power management

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

(b) 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.

(c) The distribution licensees, OA and bulk consumers shall ensure the following:

i. They shall maintain neutral grounding of their installation and shall isolate the installation whose neutral grounding is imperfect; and

ii. They shall switch off capacitor banks if voltage exceed 105% of nominal system voltage and shall switch off shunt reactors if voltage goes below 95% of nominal voltage

(d) 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.

(e) The reactive interchange of Users shall be measured and monitored by SLDC/ SRLDC.

(f) SLDC/SRLDC may direct the Users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at inter-connection points.

(g) 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 NLDC/ SLDC.

(h) 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.

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

(j) 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.

(k) Hydro and gas generating units having this capability shall operate in synchronous condenser mode operation as per instructions of the SRLDC or SLDC. Standalone synchronous condenser units shall operate as per the instructions of SRLDC or SLDC.

(l) Any commercial settlement for reactive power shall be governed as per the regulatory framework specified in **Appendix-J**.

(m) If voltage is outside the limit as specified in Regulation 12.6(a) of the Grid Code and the means of voltage control set out in Regulation 12.7(h) 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.

(n) Notwithstanding the above, SLDC may direct the State entities to curtail VAr drawal/injection in case the security of grid or safety of any equipment is endangered.

(o) In general, the State entities shall endeavour to minimize the VAr drawal at an interchange point when the voltage at that point is below 95% of rated voltage, and shall not return VAr when the voltage is above 105%. Transformer taps at the respective drawal points may be changed to control the VAr interchange only as per the instructions of SLDC.

(p) Switching in/out of 400 kV bus and line reactors in the intra-state transmission grid shall be carried out as per instructions of SRLDC/SLDC. Tap changing of all identified transformers shall be carried out as per SLDC instructions.

(q) 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. For IBRs of capacity 10 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 or the QCA shall act as aggregator for the Reactive Energy Charges for payments to and from the Pool Account at SLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer or QCA or aggregator.

12.8. General

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

Chapter 13 - Monitoring of Generation and Drawal Code

13.1. Introduction

The monitoring of generating stations output and active and reactive reserve capacity is important to evaluate the performance of generation stations. The monitoring of scheduled drawal is important to ensure that STU, Transmission Licensees and DISCOM(s) contribute towards improving system performance and observe grid discipline.

13.2. Objective

The objective of this chapter is to define the responsibilities of generating stations in monitoring of generating unit reliability and performance and DISCOM(s)/Users compliance with the scheduled drawal to assist SLDC in managing voltage and frequency.

13.3. Monitoring Procedure

(i) 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.

(ii) 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.

(iii) 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.

(iv) Generating stations shall provide to SLDC hourly generation summation outputs whenever telemetry data is not available through SCADA/ RTU equipment. Generating stations shall also provide any other logged readings that SLDC requires, for monitoring and reporting purposes.

13.4. Generating Unit Trippings

(i) 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.

(ii) 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.

13.5. Monitoring of Drawal

(i) SLDC shall continuously monitor actual MW drawal by DISCOM(s) against that scheduled by use of SCADA equipment. STU shall request SRLDC and adjacent States as appropriate to provide any additional data, if required to enable this monitoring to be carried out.

(ii) 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.

13.6. Data Requirement

Users shall submit data to SLDC as listed in Data Registration Code, termed as Monitoring of Generation.

Chapter 14 - Outage Planning Code

14.1. 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.

14.2. 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.

14.3. Annual Outage Planning and Process

(a) Each User shall provide their operational planning data including outage programme as per **Appendix-C** 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 of Users and preparing a draft annual outage Plan for State Transmission System in co-ordination with Outage Plan prepared for the region by SRPC. SLDC is authorised to defer the planned outage in case of any of the following events:

(i) Major grid disturbance;

(ii) System Isolation;

(iii) Black out in the State;

(iii) Any other event in the system that may have an adverse impact on system security by the proposed outage.

(b) Annual outage plan shall be prepared in advance for the financial year by SLDC in consultation with STU and DISCOMs 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.

(c) Generating stations connected to State grid shall furnish their proposed outage programme for the next financial year in writing by 15th 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.

(d) SLDC shall also obtain from STU, the proposed outage programme for transmission lines, equipment and sub-stations, etc., for next financial year by 15thSeptember each year. STU outage programmes shall contain identification of lines/ sub-stations, reason for outage, outage start date and duration of outage.

(e) Scheduled outage of 400 kV transmission elements and other inter-State lines shall be effected only with the approval of SRPC in coordination with SLDC.

(f) The above annual outage plan shall be reviewed by SLDC on bi-monthly basis in 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.

(g) SLDC shall submit Load Generation Balance Report (LGBR) for its control area to SRPC 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.

(h) The RPC 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.

14.4. Schedule for availing of shutdowns

(a) 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.

(b) Each User and STU shall obtain the final approval from SLDC prior to availing an outage.

14.5. Demand and Load Management

(a) The demand and load shall be managed for ensuring grid security.

(b) SLDC, in coordination with STU and Distribution Licensee(s), shall develop Automatic Demand Management scheme with emergency controls at SLDC.

(c) Whenever the power system is in an alert state or emergency state as assessed by SLDC:

(i) the respective Distribution Licensee or bulk consumer under the control area of the State shall abide by the directions of SLDC to secure the system and extreme measures like load shedding may be carried out as a last resort.

(ii) SLDC may direct Distribution Licensees or bulk consumers directly connected to STU, to restrict drawal from the grid or curtail load to ensure the stability of the grid:

Provided that load shedding shall be resorted to after the demand response option has been exhausted.

(iii) The load disconnected, if any, shall be restored as soon as possible on clearance from SLDC, after the system has been normalized.

14.6. Post-Despatch Analysis

(a) Operational analysis

(i) SLDC shall analyse the following:

1. 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;

2. Generation mix in terms of source and station-wise generation;

3. Irregular pattern in any of the system parameters mentioned in Regulation 14.6(a)(i)(1) and Regulation 14.6(a)(i)(2) of the Grid Code and reasons thereof; and

4. Extreme weather events or any other event affecting grid security.

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

(iii) 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.

(iv) SLDC shall also provide such a report to SRPC.

(v) 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.

(b) Event reporting

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

1. 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 SRLDC through voice message.

2. Written flash report shall be submitted to SLDC by the concerned User within the timeline specified in Table below.

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

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

5. 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.

(ii) SLDC shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis, which shall be discussed and finalized at the Protection sub-committee of RPC as per the timeline specified in Table below.

Sl. No.	*Grid Event^ (Classification)*	*Flash report submission deadline (Users/ SLDC)*	*Disturbance record and station event log submission deadline (Users/ SLDC)*	*Detailed report and data submission deadline (Users/ SLDC)*	*Draft report submission deadline (RLDC/ NLDC)*	*Discussion in protection committee meeting and final report submission deadline (RPC)*
1	GI-1/GI-2	8 hours	24 hours	+7 days	+7 days	+60 days
2	Near miss event	8 hours	24 hours	+7 days	+7 days	+60 days
3	GD-1	8 hours	24 hours	+7 days	+7 days	+60 days
4	GD-2/GD- 3	8 hours	24 hours	+7 days	+21 days	+60 days
5	GD-4/GD- 5	8 hours	24 hours	+7 days	+30 days	+60 days

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

(iii) Categorisation of grid incidents and grid disturbance based on severity of trippings.- The categorisation of grid incidents and grid disturbances shall be as follows:-

1. Categorisation of grid incidents in increasing order of severity,-

Category GI-1 - Tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 110 kV;

Category GI-2 - Tripping of one or more power system elements of the grid like a

generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 230 kV and above.

2. Categorization of grid disturbance in increasing order of severity,-

Category GD-1	When less than ten percent of the antecedent generation or load in a State grid is lost.
Category GD-2	When ten percent. to less than twenty percent of the antecedent generation or load in a State grid is lost.
Category GD-3	When twenty percent to less than thirty percent. of the antecedent generation or load in a State grid is lost.
Category GD-4	When thirty percent to less than forty percent of the antecedent generation or load in a State grid is lost.
Category GD-5	When forty percent or more of the antecedent generation or load in a State grid is lost.

Explanation: For the purpose of categorization of grid disturbances, percentage loss of generation or load, whichever is higher shall be considered.

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

(v) 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.

(vi) 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.

(vii) 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.

Chapter 15 - Contingency Planning Code

15.1. 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.

15.2. 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.

15.3. Contingency Planning Procedure

(a) SLDC shall prepare contingency plan to efficiently handle the following two types of contingencies:

(i) Partial system black out in the State due to multiple tripping of the transmission lines emanating from power stations/sub-station; and

(ii) Total black out in the State/Region.

(b) 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 400/230kV sub-station shall be available.

(c) In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of SRLDC 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 SRPC. 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.

15.4. Restoration Procedure

(a) The procedure for restoration of State Transmission System shall be prepared by SLDC for the following contingency (Total system black out, Partial System Blackout and Synchronisation of System Islands and System Split) and shall be in conformity to the System Restoration Procedure of the Southern Region specified under IEGC. SLDC shall review and update the restoration procedure every year.

(b) The restoration process shall take into account the generator capabilities and the operational constraints of Regional and 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.

(c) 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 / SRLDC. 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 concerned SLDC, SRLDC on a quarterly basis.

(d) Simulation studies shall be carried out by each User in coordination with SLDC / SRLDC for preparing, reviewing and updating the restoration procedures considering the following:

(i) Black start capability of the generator;

(ii) Ability of black start generator to build cranking path and sustain island;

(iii) Impact of block load switching in or out;

(iv) Line/transformer charging;

(v) Reduced fault levels; and

(vi) Protection settings under restoration condition.

(e) 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.

(f) 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.

(g) 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.

(h) Any entity extending black start support by way of injection of power as identified in Regulation 15.4(f) of the Grid Code shall be paid for actual injection @ 110 % of the normal rate of charges for deviation.

15.5. Real Time Operation

(a) 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.

(i) 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 is 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.

(ii) Alert state

Power system shall be categorized under alert state 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.

(iii) 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 equipments 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 state, 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.

(iv) 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.

(v) 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.

(b) 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.

(c) Procedure to be followed during an event:

(i) 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 SRLDC;

(ii) any warning in respect of system security issued by NLDC/ SRLDC/ 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.

(d) Operational coordination:

(i) 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.

(ii) 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.

15.6. Special Considerations

(a) During the restoration process, normal standards of voltage and frequency shall not apply.

(b) Distribution Licensees with essential loads will separately identify non-essential components of such loads, which may be kept off during system contingencies. 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.

(c) All Users shall pay special attention in carrying out the procedures so that secondary collapse due to undue haste or inappropriate loading is avoided.

(d) 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.

(e) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

Chapter 16 - Inter-User Boundary Safety Code

16.1. Introduction

This chapter sets down the requirements for maintaining safe working practices associated with inter-user 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.

16.2. Objective

The objective of this chapter is to achieve agreement and consistency on the principles of safety as specified in the CEA safety Regulations as amended from time to time.

16.3. 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 to as Designated Officer(s).

16.4. Procedure

(a) STU shall issue a list of Designated Officers (names, designations and telephone numbers) to all Users who have a direct inter-user boundary with STU. This list shall be updated promptly whenever there is change of name, designation or telephone number.

(b) All Users with a direct inter-user boundary with STU or other User's system shall issue a similar list of their Designated Officer to STU or other User, which shall be updated promptly whenever there is a change to the Designated Officer list.

(c) Whenever work across an inter-user boundary between STU and any other User or between two Users is to be carried out, the Designated Officer of the User (which may be STU), wishing to carry out work shall personally contact the other relevant Designated Officer. If the Permit to Work (PTW) cannot be obtained personally, the designated officers shall contact through telephone and exchange code words to ensure correct identification of both parties.

(d) In case the work extends over more than one shift, the Designated Officer shall ensure that the relief Designated Officer is fully briefed on the nature of the work and the code words in operation.

(e) The Designated Officers shall co-operate to establish and maintain the precautions necessary for the required work to be carried out in a safe manner. Both the established isolation and the established earth shall be locked in position, where such facilities exist, and shall be clearly identified.

(f) Work shall not commence until the Designated Officer of the User, wishing to carry out the work, is satisfied that all the safety precautions have been established. This Designated Officer shall issue agreed safety documentation (PTW) to the working party to allow work to commence. The PTW in respect of specified EHV lines and other inter-connections shall be issued with the consent of SLDC.

(g) When work is completed and safety precautions are no longer required, the Designated Officer who has been responsible for the work being carried out shall make direct contact with the other Designated Officer to return the PTW and removal of those safety precautions. Return of PTW in respect of specified EHV lines and inter-connections shall be informed to SLDC.

(h) The equipment shall only be considered as suitable for return to service when all safety precautions are confirmed as removed, by direct communication using code word contact between the two Designated Officers and return of agreed safety documentation from the working party has taken place.

(i) STU/SLDC shall develop an agreed written procedure for inter-user boundary safety and continually update it.

(j) Any dispute concerning inter-user boundary safety shall be resolved at an appropriate higher level of authority.

16.5. Special Consideration

(a) For inter-user boundary between STU and other Users circuits, all Users shall comply with the agreed safety rules, which must be in accordance with the extant Rules and amendments thereof.

(b) All equipment on inter-user boundary between STU and other Users circuits, which may be used for the purpose of safety co-ordination and establishment of isolation and earthing, shall be permanently and clearly marked with an identification number or name, that number or name being unique in that sub-station. This equipment shall be regularly inspected and maintained in accordance with manufacturer's specification.

(c) Each Designated Officer shall maintain a legibly written safety log, in chronological order, of all operations and messages relating to safety co-ordination sent and received by them. All safety logs shall be retained for a period of not less than five (5) years.

16.6. Boundaries between Systems of Entities

(a) Boundary between a Generating station and the Transmission System

The boundary shall be the line isolator of the feeder, which injects power into the transmission system. The isolator shall be in the jurisdiction of the generating company.

(b) Boundary between the Transmission System and the Distribution system

The boundary shall be the line isolator of the outgoing feeder injecting power into the distribution system. The line isolator shall be in the jurisdiction of the transmission licensee. Alternatively the boundary may be the isolator between the LV side circuit breaker of the Extra High Tension (EHT) Transformer and the 33 / 22 / 11 kV bus–bars at the EHT Sub–Station. The actual boundary shall be decided jointly by the transmission licensee and the distribution licensee.

(c) In respect of case (i) and (ii) above, at particular inter-connections both parties may jointly agree on a different boundary. In such an event the written agreement shall be submitted to the RPC /STU.

(d) Boundaries between Transmission/Distribution Licensee and Captive Generators, Co-generators and HV consumers

The boundary between the transmission/Distribution licensee and Captive Generators, Co-generators and HV consumers is the isolator in the consumer's or Captive Generators or Co-generators system, which is also the point of commencement or injection of supply.

(e) Boundaries between Inter-State Transmission System and Intra State Transmission System

For the Southern Regional Transmission System, the inter-state transmission link to the intra state system shall be in accordance with the mutual agreement between CTU and the STU. In such an event the written agreement shall be submitted to the RPC.

Chapter 17 – Reports

17.1. Periodic reports

(a) Daily and monthly reports covering performance of the State grid shall be prepared by the SLDC and published on SLDC website. The monthly report shall cover the performance of the State grid for the previous month. The monthly report shall contain the following:

(i) Frequency profile.

(ii) Maximum and minimum frequency recorded daily and daily frequency variation index (FVI).

(iii) Voltage profile.

(iv) Voltage profile of selected sub-stations.

(v) Major Generation and Transmission Outages.

(vi) Transmission Constraints.

(vii) Instances of persistent / significant non-compliance of Grid Code.

(viii) Grid Security events, leading to curtailment along with reasons.

(b) **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.

(c) These reports shall also be submitted to the Commission within a week from the due date of issue of the reports.

17.2. Operational Event/Accident Reporting

(a) Introduction

This chapter describes the reporting procedure, of reportable events in writing in the State Transmission System.

(b) 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.

(c) Reportable Incidents

Any of the following events that could affect the State Transmission System requires reporting:

(i) Exceptionally high / low system voltage or frequency.

(ii) Serious equipment problem, i.e., major circuit breaker, transformer or bus-bar etc.

(iii) Loss of Generating Unit.

(iv) Instance of Black Start.

(v) Tripping of Transmission Line, Interconnecting transformer (ICT) and capacitor banks

(vi) Major fire incidents.

(vii) Major failure of protection.

(viii) Equipment and transmission line overload.

(ix) Accidents-fatal and non-fatal.

(x) Load Crash / Loss of Load.

(xi) Violation of Security Standards.

(xii) Grid indiscipline.

(xiii) Non-compliance of SLDC instructions.

(xiv) Excessive drawal deviations.

(xv) 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.

(d) Reporting Procedure/Forms

(i) All reportable incidents occurring in lines and equipment of 66 kV and above 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.

(ii) 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.**

(iii) In 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.

(iv) 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 the source of the reportable incident. This shall not relieve any User from the obligation to report events in accordance with IE Rules.

(v) The format of such a report will be as agreed to by the Grid Code Review Committee, but will typically contain the following information:

1. Location of incident.
2. Date and time of incident.
3. Plant or equipment involved.
4. Details of relay indications with nature of fault implications.
5. Supplies interrupted and duration if applicable.
6. Amount of generation lost if applicable.
7. Brief description of incident.
8. Estimated time to return to service.
9. Name of originator.
10. Possibility of alternate arrangement of supply
11. Single line diagram
12. All relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, Data Acquisition System (DAS), etc.

(e) **Major Failure**

Following a major failure, SLDC and other Users shall co-operate to inquire into 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.

(f) **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.

Chapter 18 - Protection Code

18.1. Introduction

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.

18.2. Objective

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.

18.3. General Principles

(a) There should be a uniform protection protocol for the Users of the State grid:

(i) 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;

(ii) to have a repository of protection system, settings and events at State level;

(iii) specifying timelines for submission of data;

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

(v) to provide for periodic audit of protection system.

(b) STU shall be guided by the advice of SRPC / SRLDC 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.

(c) 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 equipments.

(d) 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.

(e) 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.

18.4. Protection Co-ordination

A Protection Coordination Committee (PCC) shall be constituted as per this Grid Code and shall be responsible for all the protection coordination functions. STU shall be responsible for arranging periodical meetings of the Protection Coordination Committee. STU shall investigate any malfunction of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection malfunction or issue as discussed and agreed to, in the periodical meetings.

18.5. Protection Protocol

(a) All Users connected to the State grid shall provide and maintain effective protection system having the reliability, selectivity, speed and sensitivity to isolate the 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.

(b) Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.

(c) Protection Coordination Committee (PCC) shall develop the protection protocol 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.

(d) 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 Protection Coordination Committee (PCC).

(e) Violation of the protection protocol of the State shall be brought to the notice of Protection Coordination Committee (PCC) by SLDC.

18.6. Protection Settings

(a) Protection Coordination Committee (PCC) shall undertake a 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 Protection Coordination Committee (PCC). The data including base case (peak and off-peak cases) files for carrying out studies shall be provided by SLDC and STU to Protection Coordination Committee (PCC).

(b) All Users connected to the grid shall:

(i) furnish the protection settings implemented for each element to Protection Coordination Committee (PCC) in a format to be prescribed by Protection Coordination Committee (PCC);

(ii) obtain approval of Protection Coordination Committee (PCC) for any revision in settings and implementation of new protection system;

(iii) intimate to Protection Coordination Committee (PCC) about the changes implemented in protection system or protection settings within a fortnight of such changes;

(iv) ensure correct and appropriate settings of protection as specified by Protection Coordination Committee (PCC); and

(v) ensure proper coordinated protection settings.

(c) Protection Coordination Committee (PCC) shall:

(i) maintain a centralized database and update the same on periodic basis in respect of State containing details of relay settings for grid elements connected to 66 kV and above. SLDC shall also maintain such database.

(ii) carry out detailed system studies once in a year, for protection settings and advise 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.

(iii) 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.

(d) The changes in the network and protection settings of grid elements connected to 66 kV and above shall be informed to Protection Coordination Committee (PCC) by SLDC and STU, as the case may be.

18.7. Protection Audit Plan

(a) Generating Stations shall conduct internal audit of their protection systems annually and any shortcomings identified shall be rectified and informed to Protection Coordination Committee (PCC) and SLDC. The audit report along with action plan for rectification of deficiencies detected if any, shall be shared with Protection Coordination Committee (PCC) and SLDC.

(b) All Users except those under Regulation 18.7(a) of the Grid Code and having sub-stations at voltage level 230 kV and above shall conduct internal audit of their protection systems annually and third-party protection audit of each sub-station once in five (5) years. The audit report along with action plan for rectification of deficiencies detected if any, shall be shared with Protection Coordination Committee (PCC) and SLDC.

(c) All Users except those under Regulation 18.7(a) of the Grid Code and having sub-stations at voltage level 66 kV / 110 kV shall conduct internal audit of their protection systems once in three (3) years. The audit report along with action plan for rectification of deficiencies detected if any, shall be shared with Protection Coordination Committee (PCC) and SLDC.

(d) After analysis of any event, Protection Coordination Committee (PCC) 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.

(e) The third-party protection audit report shall contain information sought in the format enclosed as **Appendix–I.** The protection audit reports along with action plan for rectification of deficiencies detected, if any, shall be submitted to Protection Coordination Committee (PCC) and SLDC within a month of submission of third-party audit report. The necessary compliance to such protection audit report shall be followed up regularly in Protection Coordination Committee (PCC) meetings.

(f) Annual audit plan for the next financial year shall be submitted by the Users to Protection Coordination Committee (PCC) and SLDC by 31st October. The Users shall adhere to the annual audit plan and report compliance of the same to Protection Coordination Committee (PCC) and to SLDC for record purposes.

(g) Users shall submit the following protection performance indices of previous month to Protection Coordination Committee (PCC) and SLDC on monthly basis for 66 kV and above system, which shall be reviewed by the Protection Coordination Committee (PCC):

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;

Nu 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.

(h) Each User shall also submit the reasons for performance indices less than unity of individual element-wise protection system to Protection Coordination Committee (PCC) and action plan for corrective measures. The action plan will be followed up regularly by the Protection Coordination Committee (PCC).

(i) In case any User fails to comply with the protection protocol specified by Protection Coordination Committee (PCC) or fails to undertake remedial action identified by the Protection Coordination Committee (PCC) within the specified timelines, Protection Coordination Committee (PCC) / STU may approach the Commission with all relevant details for suitable directions.

18.8. System Protection Scheme (SPS)

(a) 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.

(b) For the operational System Protection Scheme (SPS), SLDC in consultation with Protection Coordination Committee (PCC) 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 Protection Coordination Committee (PCC). The data for such studies shall be provided by STU/SLDC to the Protection Coordination Committee (PCC).

(c) 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 Protection Coordination Committee (PCC) in the format specified by Protection Coordination Committee (PCC).

(d) 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 Protection Coordination Committee (PCC) within a fortnight.

18.9. Recording Instruments

(a) All Users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.

(b) 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 Protection Coordination Committee (PCC).

(c) 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 Protection Coordination Committee (PCC) meeting.

18.10. Calibration and Testing

(a) The protection scheme shall be tested at each 765 kV, 400 kV and 230 kV sub-station by STU once in a year or immediately after any major fault, whichever is earlier. However, in case of 66 kV / 110 kV, the same shall be carried out once in every three years 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. 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.

(b) All equipment owners shall submit a testing plan for the next year to the STU/SLDC/SRPC 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 STU/SLDC/SRPC in advance.

(c) 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 SRLDC or NLDC or SRPC, as the case may be.

(d) The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports in consultation with STU, SLDC, SRPC, NLDC, CEA and CTU.

(e) The overall co-ordination between Users and STU shall be decided in the meeting of Protection Co-ordination Committee. The Protection Co-ordination Committee shall review the testing and calibration as and when needed.

(f) 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. (2) Assessment of Reactive Power Control Capability as per CEA Technical Standards for Connectivity Regulations (3) Model Validation and verification test for the complete Generator and Excitation System model including PSS. (4) Model Validation and verification of Turbine/ Governor and Load Control or Active Power/ Frequency Control Functions. (5) Testing of Governor performance and Automatic Generation Control.	Individual Unit of rating 100MW and above for Coal/ lignite, 50MW and above gas turbine and 25 MW and above for Hydro.
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Active Power Set Point change test. (5) Reactive Power (Voltage / Power Factor / Q) Set Point change test	Applicable as per CEA Technical Standards for Connectivity Regulations.
HVDC/FACTS Devices	(1) Reactive Power Controller (RPC) Capability for HVDC/FACTS (2) Filter bank adequacy assessment based on present grid condition, in consultation with NLDC. (3) Validation of response by FACTS devices as per settings.	To all ISTS HVDC as well as Intra-State HVDC/ FACTS, as applicable

18.11. Capacity Building and Certification

Capacity building, skill up-gradation, 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).

18.12. Data Requirements

Users shall provide STU with data for this chapter as specified in **Appendix-D** of Data Registration Code.

Chapter 19 - Transmission Metering Code and Distribution Metering Code

19.1. Introduction

The Transmission Metering Code and Distribution Metering Code prescribes a uniform policy in respect of electricity metering for State Transmission Utility (STU), Distribution Licensee, Generating Companies and metering of all Users of State Transmission System including Open Access customers as per the Act using State Transmission Utility and any new system interfacing with State Transmission Utility system in the State of Tamil Nadu.

19.2. Objective

The objective of the Code is to define minimum acceptable metering standards for appropriate metering of the system parameters for the purpose of accounting, commercial billing and settlement of electrical energy and also provide information that will help to optimize the system planning.

19.3. Scope

(a) The scope of the Code covers the practices that shall be employed and the facilities that shall be provided for the measurement and recording of various parameters like active/reactive/apparent power/energy, power factor, voltage, frequency, etc.

(b) The Code also specifies the requirement for calibration, testing and commissioning of metering equipment, viz., energy meters with associated accessories, current transformers, and voltage transformers. The Code indicates the technical features of various elements of the metering, data communication, testing and calibration system, the procedure for assessment of consumption in case of defective and stuck-up meters and also lays down the guidelines for resolution of disputes between different parties.

19.4. Reference Standards/ Regulations

(a) All interface meters, consumer meters and energy accounting meters shall comply with the relevant standards of Bureau of Indian Standards (BIS). If BIS Standards are not available for particular equipment or material, International Electro-Technical Commission (IEC) Standards, CBIP Technical Report or any other equivalent standard shall be followed. Whenever an international Standard or IEC Standard is followed, necessary corrections or modifications shall be made, as required for nominal system frequency, nominal system voltage, ambient temperature, humidity, and other conditions prevailing in India before actual adoption of the said Standard.

(b) All the meters of Users and systems interfacing with STU systems shall be installed and operated as per CEA Metering Regulations and amendments thereof.

19.5. Ownership

The ownership of meters shall be in accordance with CEA Metering Regulations and amendments thereof.

19.6. Other Technical Requirements for Metering

(a) Data Display Capabilities - Instantaneous Values:

The meter shall be capable to record and display (on demand) at least the following instantaneous parameters/ information:

(i) Three rms line voltages/currents

(ii) System frequency (Hz)

(iii) Power factor with sign of lag/lead.

(iv) Watt hour- Import/Export

(v) VAr - Lead/Lag

(vi) VA - Import/Export

(vii) Maximum Demand (Import/Export) during the month in Watt & VA with date and time;

(viii) Meter Serial Number

(b) Data Storage Capabilities - Cumulative Values:

The meter shall be capable to record, store and display (on demand) at least following cumulative parameters. At least five (5) registers shall be provided for each parameter, out of which one (1) register shall record energy for 24 hours in a day whereas other four (4) registers shall record Time of Day (TOD) energy during morning peak, morning off-peak, evening peak and evening off-peak durations:

(i) Watt hour - Import/Export

(ii) VAr hour - Lead/Lag while Watt hour - Import

(iii) VAr hour - Lead/Lag while Watt hour - Export

(iv) VA hour – Import/Export

(v) VAr hour during low voltage (V<97%)

(vi) VAr hour during high voltage (V>103%)

(c) Data Logging Capabilities[1] - Integrated Values:

The meter shall have sufficient memory to store any combination of at least ten (10) parameters listed in Regulation 19.6(a) and Regulation 19.6(b) of the Grid Code over minimum forty (40) days at a logging interval of fifteen (15) minutes. The State Transmission Utility shall be able to select these parameters locally through optical port using CMRI and/or remotely through communication port and/or Mobile App. At least following essential parameters shall be logged at an interval of 15 minutes:

(i) Watt hour - Import/ Export

(ii) VAr - Lead/Lag while Watt - Import

(iii) VAr - Lead/Lag while Watt - Export

(iv) VAr hour during low voltage (V<97%)

(v) VAr hour during high voltage (V>103%)

(vi) Average frequency (Hz)

(vii) Average three phase voltage.

(d) Other Parameters[2]:

Each meter shall also store the values of active energy (Import), active energy (Export), reactive energy (lag) and reactive energy (lead) separately during active energy (import) and active energy (export) conditions recorded at 24:00 hours on last day of the month for a period of at least twelve (12) months. The User shall be able to program time and day at which value of energy to be stored in the memory.

(e) Events and Abnormalities Logging Capabilities[3]:

The meter shall be able to log date and time stamped events captured with a resolution of at least one (1) second. Sufficient memory shall be provided to store at least last 100 events in the meter on First-In-First-Out (FIFO) basis as following, but not limited to:

(i) Missing potential (VT supply missing)

(ii) CT/VT Polarity reversal

(iii) Current unbalances (magnitude as well as phase unbalance) in any one of the phases or more than one phase

(iv) Voltage imbalance (magnitude as well as phase imbalance) in any one of the phases or more than one phase

(v) Supply interruptions along with the duration of each interruption

(vi) Tamper information/anomaly occurrence/anomaly restoration.

(vii) Meter internal setup/program change information

[1]In case of operational metering, the number of parameters and their logging intervals shall be decided by the Licensee as per their operational requirements.

[2]This Regulation may not be applicable for operational metering.

[3]In case of advanced metering, the meter needs to store time stamped events with at least 1ms resolution for meeting operational needs.

(f) Real Time Clock (RTC) and Calendar

The meter shall have in-built Quartz crystal based accurate Real Time Clock. The meter shall display real time in 24 hours format (hh:mm:ss). Meter shall also display the date as per Indian calendar in dd-mm-yyyy format. Thirty (30) years calendar with automatic leap year adjustment shall be provided in the meter. The accuracy of the clock and calendar shall be better than one minute per year.

(g) Time Synchronization

All meters shall have facility for time synchronisation locally and/or remotely through a Global Positioning System (GPS) or through the central computer (at CDCC) using the same port used for remote data communication.

(h) Data Retention

The logged data shall be stored in a non-volatile memory of meter with a minimum retention period of ten (10) years without any battery back-up.

(i) Data Concentration and Network Integration

The local network of all meters installed in a sub-station shall be formed using modem/multiplexer/data concentrator/LAN hub switch. This local network shall be integrated with communication network using appropriate standard protocol. Communication network may be based on Radio frequency, Microwave, Public Switched Telephone Network (PSTN), Power Line Carrier Communication (PLCC), Very Small Aperture Terminal (VSAT) network, Optical Fibre Cable (OFC), GSM, Radio or any other means of telemetry.

(j) Pulse Output

High intensity Light Emitting Diodes (LED) shall be provided on front of the meter for test calibration and accuracy check of Wh and VArh measurements.

(k) Display

The meter shall have a minimum of 7 digits Alpha-numeric Liquid Crystal Display (LCD) or Light Emitting Diode (LED) type display with bright back-light and automatic back-light time out feature. A touch key pad or push buttons shall be provided on the meter front for switching ON the display and for changing from one indication to next. Two separate push buttons shall be provided, one for scrolling and other for MD resetting.

(l) Data Security

The metering system should have the following facilities:

(i) Data encryption (coding) capability,

(ii) Mechanical seals and locks, i.e., sealing provision for terminal block, meter cover, MD reset button and all communication ports,

(iii) Message authentication algorithm capability/multi-level password protection,

(iv) Independent security across communication channels.

(m) Self-Diagnostics Feature

The meter shall have self-diagnostics feature to scan the healthiness of internal components and circuitry. On detection of any exception or fault, meter shall display the message immediately.

(n) Communication Ports

The meter shall have at least the following communication ports:

(i) One optically isolated infra-red communication port (optical port) for local communication as per IEC 1107.

(ii) One galvanically isolated Ethernet (LAN) port or RS485 serial port or RS232 serial port for remote communication.

(o) Communication Protocol

For communication by meter with external devices, meter supplier shall implement industry standard open protocol(s) like MODBUS RTU, MODBUS, TCP/IP, IEC 870-5-102, IEEE 1377, DNP 3.0, Device Language Message Specification (DLMS) or any other industry standard protocol. In case of proprietary protocol, the meter supplier shall furnish the protocol software and details of protocol followed by him. Any variation in the standard protocol for optimizing communication resources shall be detailed.

(p) Reprogramming of the meter

Utility shall be able to select the display parameters, logging parameters, timings of TOD registers, billing dates, logging interval or any other parameter locally using CMRI through optical and/or remotely using meter reprogramming software installed at CDCC through communication port(s).

(q) Data Downloading

Utility shall be able to download the logged data locally using CMRI through optical port and/ or remotely using meter interrogation software installed at CDCC through communication port(s). Any interrogation/read operation shall not delete or alter any stored meter data.

(r) Ratio and Phase Angle Correction Feature

The meter shall have facility to correct the ratio error and phase angle error of external CTs and VTs connected to it.

(s) External Auxiliary Supply

(i) The meters shall be capable of powered up with 230 V AC auxiliary supply and 110V or 220V DC supply of sub-station so that metering cores of VT are never loaded. The meter will normally be powered up by AC auxiliary supply and will be switched over automatically to DC supply only when AC auxiliary supply fails.

(ii) If any external supply is not available, self-powered type meter can be provided which derives internal power consumption from VT signal itself. In case of failure of main power supply or VT supply, meters shall be capable of being read locally using CMRI and/or remotely through communication network. Suitable maintenance-free dry battery shall be provided internally for this purpose.

(t) The Interface meters shall be of open protocol conforming to IS 15959 and of point 0.2S accuracy class. The accuracy class of Current transformers (CTs) and voltage transformers (VTs) shall not be inferior to that of associated meters. The meters shall have a non-volatile memory in which following shall be automatically stored:

(i) Average frequency for each successive 15-minutes block, as a two-digit code (00 to 99 for frequency from 49.0 to 51.0 Hz)

(ii) Net Wh transmitted during each successive 15-minutes block, upto the second decimal, with plus/minus sign.

(iii) Cumulative Wh transmittal at each midnight, in six digits including one decimal.

(iv) Cumulative VArh transmittal for voltage high condition, at each midnight, in six digits including one decimal.

(v) Cumulative VArh transmittal for voltage low condition, at each midnight, in six digits including one decimal.

(vi) Date and time blocks of failure of VT supply on any phase, as a star (*) mark.

(vii) The interface meters shall have the provision of recording of energy in 15-minutes time block as well as in 5-minutes time block as configured through software. In addition to the existing provisions of interface meters, the meters shall also have a provision of frequency resolution of 0.01Hz and they must be capable of recording Voltage and Reactive Energy at every 5-minutes and have feature of auto-time synchronization through GPS.

(viii) The respective Transmission Licensee shall be responsible for procurement and installation of Interface Energy Meters and AMR facility. The cost of Interface Energy Meter, providing AMR facility and AMC charges, shall be recovered from the user of the State Grid for whom Interface Energy Meter (s) is installed. Respective Transmission Licensee shall also be responsible for replacement of faulty meters and AMR facility at the cost of respective entity.

(ix) The periodic calibration of Interface Meters to ensure correctness and completeness of data is to be done by the respective Users.

(x) 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 and subsequent amendments thereof.

19.7. Minimum Technical Requirement for Current Transformer (CT)

(a) Single-phase type current transformers shall be used for 3 phase 4 wire and 3 phase 3 wire and 2 phase 2 wire measurement system. The secondary current rating of the CTs shall be 1 ampere or 5 amperes depending upon the total circuit burden.

(b) Either dedicated set of current transformers or dedicated core of current transformers shall be provided for metering and wherever feasible, CTs (or their cores) feeding to main meters and check meters shall be separate. The errors of the current transformers shall be checked in the laboratory or at site. However, if such facilities are not available, CT test certificates issued by Government test house or Government recognized test agency shall be referred to.

(c) The rated burden of CT shall be kept close to the circuit burden as per the requirements of the respective Metering Code to ensure minimum error. Total burden connected to each current transformer shall not exceed the rated burden of CT.

19.8. Minimum Technical Requirement for Voltage Transformers (VT)

(a) Either Electromagnetic Voltage Transformers (EVT) or Capacitive Voltage transformer (CVT) may be used for metering purpose. Generally, term VT is used to cover either EVT or CVT. The secondary voltage per phase shall be 110/√3 volts or 415/√3 volts. The VTs shall be connected to main and check meters and shall preferably be dedicated to the metering. Fuses of proper rating shall be provided at appropriate locations in the VT circuit.

(b) The errors of the VTs shall be checked in the laboratory or at site. However, if such facilities are not available, VT test certificates issued by Government test house or Government recognized test agency shall be referred to.

(c) The burden of VT connected to a circuit shall be close to the burden of the circuit as specified in the respective Metering Code to ensure minimum error and total burden connected to each VT shall not exceed the rated burden of VT. Percentage voltage drop in VT leads shall be within the permissible limits as per relevant standards.

19.9. Location and Application of Metering System

(a) Non-conventional Energy Sources

All the Main meters, Check meters and Standby meters, if required will be installed at location specified in CEA Metering Regulations and subsequent amendments thereof. However, in case of RE generators where pooling of generation is at common pooling station, meters shall be installed at outgoing feeders of pooling stations.

(b) Metering between State Transmission Utility –Distribution Licensee

(i) For measurement of power delivered by State Transmission Utility to Distribution Licensee, Main metering shall be provided on the LV side of EHV Power Transformer, i.e., 33 kV side of 220/33 kV and 110/33kV, and 11kV side of 110/11kV transformers installed in EHV sub-stations. The standby metering shall be provided on the HV side of EHV Power Transformer, i.e., 230/33 kV, 110/33kV and 110/11kV transformers installed in EHV sub-stations. Operational meters shall also be provided on all outgoing 33kV and 11kV feeders for energy audit on feeder and reconciliation of energy with respect to energy measured on LV side of EHV Power Transformer.

(ii) EHV consumers and other Distribution Licensees directly connected with EHV sub-station of respective State Transmission Licensee, shall provide Main and Check meter in their premises and Standby meter at sub-station of respective Transmission Licensee. In case of railway traction, main and check meter shall be provided on traction sub-station (TSS) and standby meter shall be at respective Transmission Licensee’s sub-station.

(c) Metering between two Distribution Licensees

The energy metering shall be provided at such points of the power lines connecting any two Distribution Systems owned by different Distribution Licensees so that the measured energy gives correct measurement of consumption by either Distribution Licensee. If installation of metering at tapped points is not feasible, it shall be provided at both the ends of feeder to which tapped feeder is connected.

(d) Sub-station Auxiliary Consumption Metering

The auxiliary consumption of STU sub-stations shall be recorded on LV side of station auxiliary transformers. If such transformer(s) is feeding other local load (colony quarters, street lights, etc.) apart from sub-station auxiliary load, separate metering shall be provided on individual feeders. Except uni-directional kWh, other data logging/ billing capabilities/energy registers/other features may not be required for this application.

(e) Open Access Customer (OAC)

In case of Generator availing/seeking open access, the metering equipment shall be installed on outgoing feeders emanating from the generating station.

In case of CGP having parallel operation, permission and connected through dedicated feeder with grid but not the consumer of DISCOMs and availing/seeking open access to sell power, the metering equipment shall be installed in Transmission Licensee’s premises. If the CGP is connected through tapped feeder, the metering equipment shall be installed at CGP end.

In case of EHV/HV consumer having contract demand/standby support with DISCOMs and availing/seeking open access, metering equipment shall be installed in the premises of Open Access Consumer.

In case of EHV/HV consumer with CGP having contract demand/standby support with DISCOMs and availing/seeking open access, metering equipment shall be installed in the premises of Open Access Consumer.

In case of any Distribution Licensee availing/seeking open access, metering equipment shall be installed at each supply point interfacing with transmission network.

(f) In addition to provisions of Regulations 19.9(a) to 19.9(e), the location and application of metering system shall be as per CEA Metering Regulations as amended.

19.10. Data Collection Systems and Data Downloading

All concerned Intra-State entities (in whose premises the Special Energy Meters are installed) shall provide Automatic Meter Reading (AMR) facility for transmitting ABT meter data to SLDC remotely. If the weekly data of Special Energy Meter is not received through AMR system installed at SLDC, the same may be downloaded and transmitted to the SLDC by the owner of the ABT meter or entities who have been authorized to take energy meter reading.

19.11. Testing Arrangements

(a) The test terminal blocks shall be provided on all meters to facilitate testing of meters. Meter testing shall be carried out as per relevant IS with electronic reference standard meter of accuracy class as given therein. For site testing, meter testing equipment with one class higher accuracy than meter under test may be used as per relevant IS.

(b) Separate test terminal blocks for testing of main and check meters shall be provided so that when one meter is under testing, the other meter continues to record actual energy during testing period. Where only one/main meter exists, an additional meter shall be put in circuit during the testing period of the main meter so that while the main meter is under testing, the other meter can record energy during the period of meter under testing.

19.12. System for Joint Inspection, Testing and Calibration

(a) The metering system located at metering points between Generating Companies, State Transmission Utility and Distribution Licensees shall be regularly inspected, tested and calibrated jointly by both the agencies involved for despatch and receipt of energy at least once in 5 years or whenever the energy and other quantity recorded by the meter are abnormal or inconsistent with electrically adjacent meters or as mutually agreed. Since the static tri-vector meters are calibrated through software at the manufacturers' works, only accuracy of the meters and functioning shall be verified during joint inspection and certified jointly by both the agencies. In case of any doubt or defect, the meter shall be replaced then and there or calibrated. In later case, error correction as determined will be applied to the meter reading for the purpose of billing contingency referred as in Regulation 19.16 of the Grid Code and comprising their readings. To cover for loss of time, spare meters shall always be kept available with the agency to whom the meter/metering point belongs. After testing, the meter shall be properly sealed and a joint report shall be prepared giving details of testing work carried out, details of old seals removed and new seals affixed, test results, further action to be taken, if any, etc. The User in whose premises the meter is located shall be responsible for proper security, protection of the metering equipment and sealing arrangement.

(b) Joint inspection shall also be carried out as and when difference in meter readings (so corrected) exceeds the sum of maximum error as per accuracy class of main and check meter. The meters shall be jointly tested/calibrated on all loads and power factors as per relevant standards through static phantom load.

19.13. Meter Sealing Provision

(a) Metering system shall be jointly sealed by the authorized representatives of the concerned parties as per the procedure agreed upon.

(b) No seal, applied pursuant to this Metering Code, shall be broken or removed except in the presence of or with the prior consent of the agency affixing the seal or on whose behalf the seal has been affixed unless it is necessary to do so in circumstances where

(i) both main and check meters are malfunctioning or there occurs a fire or similar hazard and such removal is essential and such consent cannot be obtained immediately

(ii) such action is required for the purpose of attending to the meter failure. In such circumstances, verbal consent shall be given immediately, and it must be confirmed in writing forthwith.

(c) Each party shall control the issue of its own seals and sealing pliers and shall keep proper register/record of all such pliers and the authorized persons to whom these are issued.

(d) Sealing of the metering system shall be carried out in such a manner so as not to hamper downloading of the data from the meter using CMRI or a remote meter reading system.

19.14. Access to Equipment and Data

Each constituent of the agency (Utility) on request with advance notice, shall grant full right to install metering equipment for other agency's employees, agents/duly authorized representative for inspecting, testing, calibrating, sealing, replacing the damaged equipment, collecting the data, joint reading recording, and other functions necessary and as mutually agreed.

19.15. Operation and Maintenance of the Metering System

(a) The maintenance of the meters shall be the exclusive responsibility of the owner of the meters.

(b) The operation and maintenance of the metering system includes proper installation, regular maintenance of the metering system, checking of errors of the CTs, VTs and meters, proper laying of cables and protection thereof, cleaning of connections/ joints, checking of voltage drop in the CT/VT leads, condition of meter box and enclosure, condition of seals, regular/daily reading meters and regular data retrieved through CMRI and DPS, attending any breakdown/fault on the metering system, etc.

19.16. Procedure for Assessment of Consumption in case of Defective and/or stuck-up Meter

(a) Whenever a meter goes defective, the consumption recorded by the check meter shall be referred for a period agreed mutually. The details of the malfunctioning along with date, time and snap-shot parameters along with load survey shall be retrieved from the main meter. The exact nature of the mal-functioning shall be brought out after analysing the data so retrieved and the consumption/losses recorded by the main meter shall be assessed accordingly.

(b) If main as well as check metering systems become defective, the assessment of energy consumption for the outage period shall be done as per the provisions of the TNE Supply Code or as mutually agreed by the concerned parties or at the level of Transmission Metering Committee.

19.17. Mechanism for Dispute Resolution

Any disputes relating to inter-utility metering between State Transmission Utility and any Generating Company/ Distribution Licensees/Transmission Licensees/Users shall be settled in accordance with procedures prescribed under relevant Power Purchase Agreements (PPA)/Connection Agreement or relevant Agreement, as the case may be. In case of unresolved dispute, the matter may be referred to the Commission.

19.18. Implementation of Transmission Metering Code and Distribution Metering Code

(a) For existing metering system not complying with this Codes, State Transmission Utility and Distribution Licensee shall submit a time-bound action plan to the Commission for replacement of the metering equipment in a phased manner keeping in view the emerging and future requirements like development of open power market, Act requirements, other tariff structures (two-part tariff etc.), Quality of Supply monitoring, remote monitoring/control, etc.

(b) For any new procurement of metering system, this code shall be applicable immediately.

19.19. Dynamic Code

(a) To have a dynamic Code is very valuable aspect because there is continuous and very fast up gradation in the technology of metering and communication, therefore the Code needs to be reviewed periodically as decided by the Commission.

(b) If any of the provisions of the prevailing Metering Code of this TN State Grid Code is inconsistent with any of the provisions of CEA Metering Regulations as amended from time to time, the provisions of Regulations made by CEA shall prevail.

Chapter 20 - Cyber Security Code

20.1. General

(a) 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, up-gradation of system requirements and keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements.

(b) All Users, SLDC, STU and other important third party agencies such as QCAs, Forecasting service providers, etc. as considered by the STU/SLDC 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.

20.2. 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.

20.3. Mechanism of Reporting

(a) All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000, as amended from time to time, and CEA (Cyber Security in Power Sector) Guidelines, 2021, in case of any cyber- attack.

(b) SLDC and the Commission shall also be informed by such entities in case of any instance of cyber-attack.

20.4. Cyber Security Coordination Forum

(a) The sectoral CERT (Computer Emergency Response Team) for wings of power sector, as notified by Government of India, from time to time, shall form a Cyber Security Coordination Forum with members from all concerned utilities and other statutory agencies to coordinate and deliberate on the cyber security challenges and gaps at appropriate level. A sub-committee of the same shall be formed at the regional level.

(b) The sectoral CERT shall lay down rules of procedure for carrying out their activities.

Chapter 21 - Data Registration Code

21.1. 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 define the times, when such data is to be provided by Users.

21.2. 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.

21.3. Responsibility

(a) All Users are responsible for submitting up-to-date data to STU/ SLDC in accordance with the provisions of the Grid Code.

(b) All Users shall provide STU and SLDC with the name, address and telephone number of the person responsible for sending data.

(c) STU shall inform all Users and SLDC, the name, address and telephone number of the person responsible for receiving data.

(d) STU shall provide up-to-date data to Users as provided in the relevant schedule of the Grid Code.

(e) Responsibility for the correctness of data rests with the concerned User providing the data.

21.4. 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.

21.5. 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.

21.6. Methods of submitting Data

(a) 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.

(b) 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.

21.7. Special Considerations

(a) STU and SLDC and any other User may at any time make reasonable request for extra data as necessary.

(b) STU shall supply data, required/requested by SLDC for system operation, from data bank to SLDC.

Chapter 22 – Miscellaneous

22.1. 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.

22.2. 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.

22.3. Repeal and Savings

(a) Save as otherwise provided in this Grid Code, the “Tamil Nadu Electricity Grid Code” notified by the Commission vide Notification No.TNERC/GC/13/1, dated 19.10.2005 along with all amendments thereto shall stand repealed from the date of commencement of this Code.

(b) Notwithstanding anything contained contrary to any other regulations of the Commission for the time being in force, the procedure for scheduling and Despatch of power shall be as per this Code only.

(c) 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 or to prevent abuse of the process of law.

(d) 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.

(e) 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.

22.4. 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.

22.5. 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)

Chennai-600 032,
17th February 2026.

S. JOHN SUNDARARAJ,
Secretary (in-charge),
Tamil Nadu Electricity Regulatory Commission.

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 - 6 RESOURCE ADEQUACY AND SYSTEM PLANNING CODE

CHAPTER - 7 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, 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 Rating (MVA) Speed (RPM) Terminal voltage (kV) Rated Power Factor Reactive Power Capability (MVAr) in the range 0.95 of leading and 0.85 lagging Short Circuit Ratio Direct axis (saturated) transient reactance (% on MVA rating) Direct axis (saturated) sub-transient reactance (% on MVA rating)

		Auxiliary Power Requirement MW and MVAr Capability curve
iv	Generator Transformer	Type Rated capacity (MVA) Voltage Ratio (HV/LV) Tap change Range (+ % to - %) 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 Whether catchment receiving discharges from other reservoir or power plant. Full reservoir level Minimum draw down level. Tail race level Design Head Reservoir level versus energy potential curve Restraint, if any, in water discharges 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 b. Minimum 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 Rating (MVA) Speed (RPM) Terminal voltage (kV) Rated Power Factor Reactive Power Capability (MVAr) in the range 0.95 of leading and 0.85 of lagging MW & MVAr capability curve of generating unit Short Circuit Ratio Direct axis transient (saturated) reactance (% on rated MVA) Direct axis sub-transient (saturated) reactance (% on rated MVA) Auxiliary Power Requirement (MW)
iv	Generator - Transformer	a. Type b. Rated Capacity (MVA) c. Voltage Ratio HV/LV d. Tap change Range (+% to -%) 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). a. Resistance/km b. Inductance/km 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 Tamil Nadu 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 – 6 RESOURCE ADEQUACY ANDSYSTEM PLANNING CODE

CHAPTER – 7 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.		**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, Alternators,
		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.		**PROTECTION AND METERING**
	i.	Full description including settings for all relays and protection systems on the
		Generating Unit, Generator unit Transformer, Auxiliary Transformer
		motor of major equipments listed, but not limited to, under Sec. 3.
	ii.	Full description including settings for all relays installed on all outgoing feeders from
		Power Station switchyard, Tie circuit breakers, and incoming circuit
	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.
	v.	Full description of operational and commercial metering schemes.
B.1.1.		**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. (a) Lightning Arresters - (b)Technical data (c) Communication – (d) Details of Communications equipment installed at points of connections. (e) Basic Insulation Level (kV) i. Bus bar. ii. Switchgear. iii. Transformer Bushings 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: a. Hot b. Warm c. Cold
v.	Maximum Generating Unit loading rates for the following conditions: a. Hot b. Warm c. Cold
vi.	Minimum load without oil support (MW).

B.1.1.8 GENERAL STATUS

i	Detailed Project report.
ii	Status Report (a) Land (b) Coal (c) Water (d) Environmental clearance (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. a) Turbines (HP) b) Generators (MVA) c) Generator Transformers (MVA) 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. a) Salient features b) Type of Reservoir i. Multipurpose ii. For Power c) Operating Table with i. Area capacity curves and 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.

(e) 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).
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. (a) Topographical survey (b) Geological survey (c) Land (d) Environmental Clearance (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. (a) Topographical survey (b) Geological survey (c) Land (d) Environmental Clearance (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 Exciters)
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 Communication - Details of communication equipment installed at points of connections. Basic Insulation Level (kV) - i. Bus bar. ii. Switchgear. iii. Transformer bushings. 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 for 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 for synchronizing.
iv	Time required for synchronizing a Generating Unit for the following conditions: a. Hot b. Warm c. Cold
v	Maximum Generating Unit loading rates for the following conditions: a. Hot b. Warm c. Cold

vi	Minimum load without oil support (MW).

B.1.3.8 GENERAL STATUS

i	Detailed Project report
ii	Status Report (a) Land (b) Gas/Liquid Fuel (c) Water (d) Environmental clearance (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 the 33kV bus at the 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: i. Transformers. ii. Circuits. iii. Circuit breakers. 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. (a) Operating voltage (kV). (b) Positive Phase sequence reactance (pu on 100 MVA) X1 (c) Positive Phase sequence resistance (pu on 100 MVA) R1 (d) Positive Phase sequence susceptance (pu on 100 MVA) B1 (e) Zero Phase sequence reactance (pu on 100 MVA) X0 (f) Zero Phase sequence resistance (pu on 100 MVA) R0 (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-load/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 14 - 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.	15th November of current year
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.	25th of current month
Hourly demand estimates for the day ahead.	10.00 Hours every day.

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.	Soon after Connection is made

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.	15th November each year
MW, which will not be available as a result of Outage.	15th November each year
Preferred start date and start-time or range of start dates and start times and period of Outage.	15th November each year
If outages are required to meet statutory requirements, then the latest-date by which Outage must be taken.	15th November each year

C.1.3.2 YEAR AHEAD SRPC OUTAGE PROGRAMME

(Affecting Transmission System)

Items	Due date / Time
MW, which will not be available as a result of an Outage from Imports through external Connections.	1st November each year
Start-date and start-time and period of Outage.	1st November each year

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	30th November each year
Start-date and start-time and period of Outage.	30th November each year

C.1.3.4 YEAR AHEAD DISCOMs OUTAGE PROGRAMME

Items	Due date / Time
Loads in MW not available from any Connection point.	15th November each year
Identification of Connection point.	15th November each year
Period of suspension of Drawal with start-date and start-time.	15th November each year

C.1.3.5 STU's OVERALL OUTAGE PROGRAMME

Item	Due date/Time
Report on proposed Outage programme to SRPC	15th February each year
Release of finally agreed Outage plan	15th February each year

C- 2. GENERATION SCHEDULING DATA

REFER TO CHAPTER -11: SCHEDULE AND DESPATCH CODE

C-3 CAPABILITY DATA

REFER TO:

CHAPTER 12-FREQUENCY AND VOLTAGE MANAGEMENT CODE

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 RESPONSE TO FREQUENCY CHANGE

REFER TO:

CHAPTER 12-FREQUENCY AND VOLTAGE MANAGEMENT CODE

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 13 - MONITORING OF GENERATION AND DRAWAL CODE

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 15 - CONTINGENCY PLANNING CODE

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 the **Connection**

Appendix D: Protection Data

REFER TO:

CHAPTER 18 – PROTECTION CODE

Item	Due date / Time
For SSGS 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 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 19 - TRANSMISSION METERING CODE

Item	Due date / Time
For SSGS 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 **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 6 - 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 the Commission.

Planning Criterion

(a) The planning criterion is based on the security philosophy on which ISTS and InSTS 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 InSTS 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 110 kV D/C line or,
- Outage of a 230kV 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 Bi-pole line, or,
- Outage of a 765kV S/C line.

(ii) The above contingencies shall be considered assuming as pre-contingency system depletion (Planned Outage) of another 230kV 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 / InSTS 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 7 – Grid connectivity conditions

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 17 - Reports

Operational Event / Incidence reporting

FLASH REPORT : SLDC/STU/USERS/TRANSMISSION LICENSEE/GENERATORS			
Agency Name/Month-Year/GD or GI- Number			
Name of Incident:			
1. Date and Time:			
2. Antecedent Conditions			
I. Frequency of the 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: Third Party Protection System Checking & Validation Template For A Sub-Station

1. INTRODUCTION

(i) The audit reports, along with action plan for rectification of deficiencies found, if any, shall be submitted to PCC 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 trippings (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 output available for last 6 trippings (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, PCC 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 Over current/ 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) Bus-bar Protection Relay

a. Bus-bar and redundant relay make and model

b. Type of Bus-bar 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-J: Reactive Power Compensation

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 state 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 state entities, VAr exchanges with Intra State Transmission System shall be priced as follows:

(i) The State entity pays for VAr drawal when voltage is below 97%

(ii) The State entity gets paid for VAr return when voltage is below 97%.

(iii) The State entity gets paid for VAr drawal when voltage is above103%.

(iv) The State entity pays for VAr return when voltage is above 103%.

Where all voltage measurements are at the interface point with ISTS / InSTS.

(b) The Reactive Energy Charges shall be fixed by the Commission vide separate order / notification from time to time.

(c) The SLDC shall issue monthly statement for Reactive Energy Charges to all intra-state entities and shall finalize methodology & procedure for carrying out reactive energy accounting of intra state entities within 60 days of notification of these regulations duly consulting the stakeholders and submit to the Commission for approval.

Appendix-K: Summary of the procedures to be formulated by the SLDC

The SLDC shall formulate the following procedures duly consulting the stakeholders concerned and submit the same to the Commission for approval within 60 days from the date of issue of this Code:

1. Procedure for functioning of Grid Code Review Committee as per the Regulation 5.3(a) of this Code;

2. Procedure for first time energization as per the Regulation 7.7(m)(vi) of this Code;

3. Detailed operating procedure of SLDC (Regulation 10.3(c)) including operating procedures under grid disturbance/emergencies (Regulation 8.3(d)), restoration procedure (Regulation 15.4(a)), Procedure for carrying out Reactive Energy Accounting (Appendix-J of this Code), etc.;

4. Detailed procedure for Scheduling and Despatch;

5. Procedures for functioning of various Committees to be formulated under this Code;

6. Any other procedures essentially required for day-to-day operation.

EXPLANATORY STATEMENT

The Tamil Nadu Electricity Regulatory Commission (hereinafter referred to as "the Commission") notified the Tamil Nadu Electricity Grid Code (TNEGC) vide Notification No. TNERC/GC/13/1 dated 19.10.2005, which came into effect from 14.12.2005.

The Central Electricity Regulatory Commission (CERC), upon notifying the Indian Electricity Grid Code (IEGC), 2023, revised the IEGC, 2010 and introduced provisions including, inter alia, declaration of the date of commercial operation of generating stations, mandatory trial runs for generators, system planning for 765 kV circuits, compensation mechanisms for under-utilized thermal power plants, and enhanced flexibility in revising capacity schedules.

In alignment therewith, it is proposed to incorporate the aforesaid provisions into the State Grid Code, along with an expanded operating frequency band of 49.90 Hz to 50.05 Hz.

The installation of LVRT / HVRT protection systems in Wind and solar generators has been stipulated in this regulation as mandated in the IEGC / CEA (Technical standards of connectivity to the Grid) Regulations as amended from time to time.

The Central Electricity Authority (CEA) vide its letter dated 28.04.2025 advised all State Electricity Regulatory Commissions (SERCs) and Joint Electricity Regulatory Commissions (JERCs) to forthwith review and amend their respective State Grid Codes in consonance with the IEGC, 2023.

Further, the Ministry of Power, Government of India, vide its letter dated 24.12.2025, directed the SERCs to align their State Grid Codes with the IEGC, 2023.Pursuant to the above directions and in exercise of the powers conferred under Sections 61, 86(1)(e), and other enabling provisions of the Electricity Act, 2003, the Commission hereby repeals the Tamil Nadu Electricity Grid Code, 2005, and notifies the Tamil Nadu Electricity Grid Code, 2026 (hereinafter referred to as "the Grid Code") to ensure efficient supervision, grid control, and operation of the intra-State power system.

The Grid Code incorporates the provisions of the IEGC, 2023, subject to the following minor deviations tailored to State-specific requirements:

1. Revisions to Declared Capacity and schedules shall take effect from the 6th time block, as against the 7th or 8th time block stipulated in the IEGC, 2023;

2. In the event of bottlenecks in power evacuation arising from outages, failures, or limitations in the transmission system or other constraints and in the interest of better system operation by SLDC, revisions to dispatch and drawal schedules shall take effect from the next time block, as against the 7th or 8th time block under the IEGC, 2023, to optimize system operation and facilitate more integration of renewable energy into the grid;

3. The definition of the term "Hot Start" stands modified in accordance with the CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022, for enhanced clarity;

4. The definition of the term "Drawee Entity" has been incorporated into the Grid Code for greater precision;

5. Voltage operating limits for 220 kV and 110 kV systems shall follow Tamil Nadu-specific bands (e.g., ±10% for 220 kV), as against IEGC uniform limits, to accommodate regional transmission constraints and high renewable energy penetration in southern districts; and

6. Renewable energy generators shall submit day-ahead forecasts with ±15% tolerance (extendable to ±20% during monsoons), diverging from IEGC's ±12% band, to better reflect Tamil Nadu's variable solar/wind profile and TNERC RE integration mandates.

Accordingly, this Grid Code is framed to give effect to the Government of India's policy of "One Nation, One Grid", with a view to enable integrated, coordinated and efficient operation of the power system, to ensure grid security, system reliability, operational discipline and system stability and to provide safe, secure and reliable operation of the State Grid in conformity with national grid operation principles, including all allied operational, protection and safety aspects.

(By Order of the Commission)

Chennai-600 032,
17th February 2026.

S. JOHN SUNDARARAJ,
Secretary (in-charge),
Tamil Nadu Electricity Regulatory Commission.

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