MADHYA PRADESH ELECTRICITY REGULATORY COMMISSION
BHOPAL

Dated: 13.03.2024

NOTIFICATION

No. MPERC/2024/672 - In exercise of powers under Section 86(1)(h) of the Electricity Act 2003, the Madhya Pradesh Electricity Regulatory Commission hereby, specifies the Madhya Pradesh Electricity Grid Code (Revision- III), 2024.

Madhya Pradesh Electricity Grid Code (Revision-III), 2024 {RG-14 (III) of 2024}

PART I
GENERAL CODE
CHAPTER I
GENERAL

1. Short Title, Commencement and Applicability

(1) This Code shall be called **"The Madhya Pradesh Electricity Grid Code (Revision-III), 2024" {RG-14 (III) of 2024}**.

(2) This Code shall come into force from the date of its publication in the Official Gazette of the Government of Madhya Pradesh.

(3) The Madhya Pradesh Electricity Grid Code shall extend to the whole State of Madhya Pradesh and shall apply to State Load Despatch Centre of Madhya Pradesh, every User who is connected to and / or uses the Intra-State Transmission System, State Transmission Utility (STU) and all Intra-State Transmission Licensees.

1.1 Objectives

The Grid Code governs the boundary between STU and Users as well as establishes guidelines for operation of facilities for those who are connected and will use the Intra-State Transmission System. It lays down both the information requirements and procedures governing the relationship between STU and Users. The principal objectives of the Madhya Pradesh Electricity Grid Code are:

- To provide clarity and certainty to STU, MPPGCL, IPP/CGP/REGS within the State of Madhya Pradesh, Distribution Licensees and any Open Access customers connected to Intra-State Transmission System by stating their respective roles, responsibilities and obligations with respect to the operation of the State Transmission System.
- To improve the grid stability and set minimum standards of system performance.
- To document the common knowledge or normal practice in writing for ease of reference and help in compliance.
- To specify the performance characteristics for generating plants.
- To improve co-operation by providing a mechanism for clear and consistent disclosure of all information.
- To indicate how generation is to be scheduled and dispatched.

1.2 Structure of Madhya Pradesh Electricity Grid Code

The Madhya Pradesh Electricity Grid Code has been divided into the following parts:

I. Management of Code

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

II. Planning Code

Planning Code includes:

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

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

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

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

(e) **Commissioning and Commercial Operation Code** covers aspects related to drawal of start-up power from the grid and injection of infirm power into the grid, trial run operation, documents and tests required to be furnished before declaration of Date of Commercial Operation (COD) and requirements for declaration of COD.

III. Load Despatch & System Operation Code

Load Despatch & System Operation Code includes:

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

(b) **Schedule and Despatch Code** specifies 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.

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

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

(e) **Outage Planning Code** specifies the procedures relating to co-ordination among Users, STU, Generating Stations, and Distribution Licensees in case of outages.

(f) **Contingency Planning Code** describes the steps to be followed during the recovery process by all Users in the event of total or partial blackout of State Transmission System or Regional Transmission System.

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

IV. Protection Code

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

V. Metering Code

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

VI. Cyber Security Code

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

VII. Data Registration Code

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

1.3 Scope

1.3.1 Madhya Pradesh Electricity Grid Code (MPEGC) 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.

1.3.2 The Grid Code shall be complied with by STU in its capacity as 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, in the course of generation, transmission and distribution of electricity.

1.4 Implementation and Operation of the Grid Code

1.4.1 The connectivity criteria and other provisions of the Grid Code shall be applicable to the Connections and equipment procured/provided for new works/ replacements from the date from which the Grid Code is made effective.

1.4.2 The existing connections and equipment shall continue to operate till such time the Operation and Co-ordination Committee (OCC) considers necessary alterations. However, operational aspects of the Grid Code shall have no such relaxation and shall apply with immediate effect.

1.4.3 All Users are required to comply with the Grid Code, which shall be enforced by STU.

Users must provide STU reasonable rights of access, service and facilities necessary to discharge its responsibilities in the Users' premises and to comply with instructions as issued by STU reasonably required to implement and enforce the Grid Code.

1.4.4 The operation of the Grid Code will be reviewed regularly by the Grid Code Review Committee in accordance with the provisions of the relevant chapter of the Grid Code.

1.5 General Requirements

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

1.5.2 Users must therefore, understand and accept that STU in such unforeseen circumstances may be required to act decisively to discharge its obligations under its Grid Code. SSGS, IPPs, REGS and DISCOMs shall provide such reasonable co-operation and assistance as STU may request in such circumstances.

1.6 Code Responsibilities

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

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

1.7 Confidentiality

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

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

1.8 Dispute Settlement Procedures

1.8.1 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.

1.8.2 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.

1.9 Communication between STU and Users

1.9.1 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.

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

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

1.10 Availability of Madhya Pradesh Electricity Grid Code

In addition to Commission website, the notified copy of Madhya Pradesh Electricity Grid Code shall also be placed on the website of State Load Despatch Centre (SLDC) and State Transmission Utility (STU) for Users reference.

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CHAPTER 2

DEFINITIONS

2. Definitions

In this Grid Code, unless the context otherwise requires:

Sr. No.	Defined Term	Definition
1	Act	The Electricity Act 2003 (Central Act No. 36 of 2003).
2	Alert State	means the state in which the operational parameters of the power system are within their respective operational limits, but a single n-1 contingency leads to violation of system security.
3	Ancillary Services	shall have the same meaning as defined in Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022 and amendments thereof.
4	Apparatus	means Electrical apparatus and includes all machines, fittings, accessories and appliances in which conductors are used.
5	Appendix	An Appendix to a chapter of the Grid Code.
6	Area Control Error (ACE)	shall have the same meaning as defined in IEGC, 2023 and amendments thereof.
7	Area of Supply	shall have the same meaning as defined in 'The Conditions of distribution licence for distribution licensee (including deemed licensee), 2004' and amendments thereof.
8	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.
9	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.
10	Auxiliary Energy Consumption	shall have the same meaning as defined in MPERC (Terms and Conditions for determination of Generation Tariff) Regulations and amendments thereof.
11	Available Capacity	shall have the same meaning as defined in MPERC (Forecasting, Scheduling, Deviation Settlement Mechanism and related matters of Wind and Solar generating stations) Regulations, 2018 and amendments thereof.
12	Available Transfer Capability (ATC)	means the transfer capability of the inter-control area transmission system available for scheduling

Sr. No.	Defined Term	Definition
		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.
13	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/ WRLDC.
14	Beneficiary	means a person who has a share in a Generating Station.
15	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.
16	Blackout	means a condition at a specific time where a part or all the operations of the power system have got suspended.
17	Black Start	means a process of recovery from total or partial blackout of the State Transmission System.
18	Breakdown	means an occurrence relating to equipment of supply system which prevents its normal functioning.
19	BSC	means Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and amendments thereof.
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.

Sr. No.	Defined Term	Definition
26	CEA Flexible Operation Regulations	means Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 and amendments thereof.
27	CEA Grid Standards Regulations	means Central Electricity Authority (Grid Standards) Regulations, 2010 and amendments thereof.
28	CEA Manual of transmission planning criteria	means Central Electricity Authority (Manual of transmission planning criteria), 2023 and amendments thereof.
29	CEA Metering Regulations	means Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 and amendments thereof.
30	CEA Safety Regulations	means Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023 and amendments thereof.
31	CEA Technical Standards for Communication Regulations	means Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020 and amendments thereof.
32	CEA Technical Standards for Connectivity Regulations	means Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and amendments thereof.
33	CEA Technical Standards for Construction Regulations	means Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and amendments thereof.
34	CERC	Central Electricity Regulatory Commission
35	CERC Communication System Regulations	means CERC (Communication System for Inter-State Transmission of Electricity) Regulations, 2017 and amendments thereof.
36	Central Generating Station	shall mean generating stations owned by the companies owned or controlled by the Central Government.
37	Central Transmission Utility (CTU)	shall mean utility notified by the Government of India under sub-section (1) of Section 38 of the Act
38	Chapter	A Chapter or part of this Grid Code, which is, identified as covering a specific topic.
39	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).

Sr. No.	Defined Term	Definition
40	Collective Transaction	shall have the same meaning as assigned to it in Central Electricity Regulatory Commission (Power Market) Regulations, 2021 and amendments thereof.
41	Commission/ MPERC	shall mean Madhya Pradesh Electricity Regulatory Commission.
42	Congestion	means a situation where the demand for transmission capacity or power flow on any transmission corridor exceeds its Available Transfer Capability.
43	Connection Agreement	means an agreement between STU and a User setting out the terms relating to the Connection to and/or use of the State Transmission System.
44	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.
45	Connection point	means a point at which a Plant and/or Apparatus connects to the Transmission/ Distribution System.
46	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.
47	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.
48	Consumer	shall have the same meaning as defined in the Act.
49	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.
50	Control Centre	includes NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOMs LDC whichever applicable, including main and backup Centres, as applicable.
51	Data Acquisition System (DAS)	means a system for recording the sequence of operation in time, of the relays or equipment as well as

Sr. No.	Defined Term	Definition
		the measurement of pre-selected system parameters.
52	Date of Commercial Operation (COD)	shall have the same meaning as specified in Chapter-7 of the Grid Code.
53	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.
54	Demand	means the demand for active power in MW and reactive power in MVAr.
55	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.
56	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.
57	Deviation Charges	shall have the same meaning as defined in Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and amendments thereof.
58	Deviation Settlement Mechanism (DSM) Regulations	shall have the same meaning as defined in Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and amendments thereof.
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 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.

Sr. No.	Defined Term	Definition
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	EHV or Extra High Voltage	Nominal voltage levels of 132 kV and above.
65	EHV Consumer	means a person to whom electricity is provided and who has a dedicated supply at 132 kV or above.
66	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.
67	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.
68	Entitlement	means the share of a DISCOMs (in MW and MWh) in the installed Capacity / output Capability of a Generating Station.
69	Event	means an unscheduled or unplanned occurrence in the grid including faults, incidents and breakdowns.
70	Event Logging	means a device for recording the chronological sequence of operations of the relays and other equipment.
71	Ex-Power Plant	means net MW or MWh output of a generating station, after deducting auxiliary consumption and transformation losses.
72	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.
73	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.
74	Forced Outage	means an outage of a generating unit or a transmission facility due to a fault or any other reasons, which have

Sr. No.	Defined Term	Definition
		not been planned.
75	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.
76	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).
77	Frequency Response Obligation (FRO)	means the minimum frequency response a control area has to provide in the event of any frequency deviation.
78	Frequency Response Performance (FRP)	means the ratio of actual frequency response with frequency response obligation.
79	Generating Company	shall have the same meaning as defined in sub- section (28) of Section 2 of the Act.
80	Generating Station	shall have the same meaning as defined in sub- section (30) of Section 2 of the Act.
81	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.
82	Generator	means a person or agency who generates electricity and who is subjected to Grid Code either pursuant to

Sr. No.	Defined Term	Definition
		any agreement with STU or otherwise.
83	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.
84	Grid Code / Code	means MP Electricity Grid Code, 2024 issued by the Commission in accordance with the terms of section 86 (1) (h) of the Act.
85	Grid Code Review Committee (GCRC)	means the Committee set up under Chapter-3 (Management of the Grid Code) of this Grid Code.
86	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.
87	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.
88	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.
89	High Voltage (HV)	means the voltage higher than 650 volts but not exceeding 33,000 volts under normal conditions.
90	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).
91	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).
92	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.
93	Indian Standard (IS)	means the standard established and published by the

Sr. No.	Defined Term	Definition
		Bureau of Indian Standards (BIS) and subsequent updations.
94	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.
95	Infirm Power	shall have the same meaning as defined in MPERC Generation Tariff Regulations and amendments thereof.
96	Inter-State Transmission System (ISTS)	shall have the same meaning as defined in sub- section (36) of Section 2 of the Act
97	Inter Connecting Transformer (ICT)	means the transformer connecting EHV lines of different voltage levels.
98	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.
99	Intra-State Transmission System (InSTS)	shall have the same meaning as defined in sub- section (37) of Section 2 of the Act.
100	LDC	means Load Despatch Centre
101	Licensee	shall have the same meaning as defined in the Act.
102	Load	means the active, reactive or apparent power consumed by a utility/installation of consumer.
103	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.
104	Maximum Continuous Rating (MCR)	means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters.
105	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.
106	MPPGCL	means Madhya Pradesh Power Generating Company Limited.
107	MPPMCL	means Madhya Pradesh Power Management Company

Sr. No.	Defined Term	Definition
		Limited.
108	MPPTCL	means Madhya Pradesh Power Transmission Company Limited.
109	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.
110	National Load Despatch Centre (NLDC)	means the centre established under sub-section (1) of Section 26 of the Act.
111	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
112	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
113	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.
114	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.
115	Open Access	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Terms and Conditions for Intra-State Open Access in Madhya Pradesh) Regulations, 2021 and amendments thereof.
116	Open Access Customer (OAC)	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Terms and Conditions for Intra-State Open Access in Madhya Pradesh) Regulations, 2021 and amendments thereof.
117	Operating range	means the operating range of frequency and voltage as specified in Chapter-10 of this Grid Code.
118	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

Sr. No.	Defined Term	Definition
		circuit level, inertia.
119	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.
120	Peak Period	means that period in a day when electrical demand is at its highest.
121	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.
122	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.
123	Pool Account	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Forecasting, Scheduling, Deviation Settlement Mechanism and related matters of Wind and Solar generating stations) Regulations and amendments thereof.
124	Pooling Station	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Forecasting, Scheduling, Deviation Settlement Mechanism and related matters of Wind and Solar generating stations) Regulations and amendments thereof.
125	Power System	shall have the same meaning as defined in sub- section (50) of Section 2 of the Act
126	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.
127	Qualified Coordinating Agency (QCA)	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Forecasting, Scheduling, Deviation Settlement

Sr. No.	Defined Term	Definition
		Mechanism and related matters of Wind and Solar generating stations) Regulations and amendments thereof.
128	Ramp Rate	means rate of change of a generating station output expressed in % MW per minute.
129	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.
130	Reference contingency	means the maximum positive power deviation occurring instantaneously between generation and demand and considered for estimation of reserves.
131	Regional Load Despatch Centre (RLDC)	means the Centre established under sub-section (1) of Section 27 of the Act.
132	Regional Power Committee (RPC)	shall have the same meaning as defined in the Act.
133	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.
134	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.
135	Restorative State	means a condition in which control action is being taken to reconnect the system elements and to restore system load.
136	Renewable Hybrid Energy Project/ Renewable Hybrid Generating Station (RHGS)	shall have the same meaning as defined in Madhya Pradesh Electricity Regulatory Commission (Co-generation and Generation of Electricity from Renewable Sources of Energy) Regulations and amendments thereof.
137	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.
138	Secondary Reserve	means the maximum quantum of power, which can be activated through secondary control signal by which injection or drawal or consumption of an Secondary Reserve Ancillary Service provider is adjusted in

Sr. No.	Defined Term	Definition
		accordance with CERC (Ancillary Services) Regulations, 2022 and amendments thereof.
139	Seller	means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with the appropriate Regulations.
140	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.
141	State	means the State of Madhya Pradesh.
142	State Load Despatch Centre (SLDC)	means the centre established under sub section (1) of Section 31 of the Act to ensure integrated operation of the power system in the State.
143	State Sector Generating Station (SSGS)	means power station within the State including Pench hydel Power Station (operated by MPPGCL), except Inter-State Generating Stations (ISGS) and Independent Power producer generating stations (IPPs)/Captive Generating Plant (CGP)/REGS located within the State of MP in which State has its share.
144	State Transmission System (STS)	means the system of EHV electric lines 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.
145	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.
146	Sub-LDC	means the Load Despatch Centres set up at Bhopal and Indore.
147	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.
148	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

Sr. No.	Defined Term	Definition
		construed accordingly.
149	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.
150	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.
151	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.
152	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.
153	Transmission Licence	means the Licence granted to Transmission Utility by the Commission under Section 14 of the Act.
154	Transmission Planning Criteria	means the criteria issued by CEA for transmission system planning.
155	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.
156	Trial Operation or Trial Run	shall have the same meaning as specified in this Grid Code, as applicable.
157	TSA	means Transmission Service Agreement.
158	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.

Sr. No.	Defined Term	Definition
159	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.
160	Western Region / Region	means region comprising States and Union Territory of Gujarat, Madhya Pradesh, Chhattisgarh, Goa, Maharashtra, Dadra & Nagar Haveli, Daman & Diu.
161	WRLDC	means Western Regional Load Despatch Centre.
162	WRPC	means Western Regional Power Committee.
163	Wind-Solar Seller (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.

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CHAPTER 3

MANAGEMENT OF THE GRID CODE

3. Management of the Grid Code

3.1 Introduction

3.1.1 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 3.4** of the Grid Code, shall be established.

3.1.2 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.

3.1.3 The changes/revisions proposed by the Grid Code Review Committee shall be consistent/ compatible with IEGC and amendments thereof.

3.1.4 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.

3.2 Objective

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

3.3 Responsibilities

3.3.1 STU shall be responsible for managing and enforcing the State Grid Code.

3.3.2 STU shall establish and service the requirements of the Grid Code Review Committee in accordance with the provisions of **Regulation 3.5** of the Grid Code.

3.3.3 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 Madhya Pradesh Electricity Grid Code.

3.4 Grid Code Review Committee

3.4.1 The Commission shall approve the constitution of Grid Code Review Committee through separate order.

3.4.2 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.

3.5 Grid Code Review Committee Proceedings

3.5.1 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.

3.5.2 The functions of the Grid Code Review Committee are as follows:

(a) To keep the Grid Code and its implementation under scrutiny and review.

(b) 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 reoccurrence.

(c) To consider all requests for amendment to the Grid Code, which any User makes and take action as per **Regulation 3.5.2(b)** above, if found appropriate after consideration.

(d) To issue guidance on the interpretation and implementation of the Grid Code.

(e) To examine problems/ issues raised by Users.

3.5.3 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.

3.5.4 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 .

3.6 Grid Code Review and Revisions

3.6.1 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.

3.6.2 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.

3.6.3 Member Secretary of the Committee shall send to the Commission, the following reports at

the conclusion of each review meeting of the Committee:

(a) A report on the outcome of such review meeting;

(b) Any proposed revisions to the Grid Code as STU reasonably thinks necessary for the achievement of the objectives of this Code;

(c) All written representations or objections from Users arising during the review/ consultation process.

3.6.4 All revisions in the Grid Code shall be made by the Commission.

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

3.6.6 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.

3.6.7 The Commission shall reserve the right to review the Grid Code as and when required.

3.7 Functional Committees

3.7.1 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)	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)

3.7.2 The Commission shall approve the constitution of Functional Committees through separate order.

3.7.3 **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 **Regulation 6.1 of Performance Standards** of Madhya Pradesh Electricity Regulatory Commission (Distribution Performance Standards) (Revision-II) Regulations, 2012 [No. RG-8(II) of 2012] and amendments thereof and taking remedial measure 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 system for all eligible generating stations.

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

3.7.4 **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.

(d) 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.

3.7.5 **Transmission Metering Committee (TMC)**

(a) Transmission Metering Committee (TMC) shall ensure implementation of Metering Code by the Users and discharge their obligations under the Metering Code.

(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.

(d) Transmission Metering Committee (TMC) shall conduct the following functions:

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

ii. To consider all the requests for amendment to the Metering Code, which any user makes.

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

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

3.8 Monitoring of Compliance

3.8.1 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 Madhya Pradesh Electricity Grid Code and with the procedures developed under such provisions:

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

3.8.2 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.

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

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

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

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

3.8.7 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 Madhya Pradesh Electricity Grid Code, it shall be referred to the Commission by SLDC for decision:

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

3.8.8 If any Transmission Licensee or any User fails to comply with the directions issued under **Regulation 3.8.6** of the Grid Code, he shall be liable to penalty not exceeding Rs. five (5) Lakh.

3.8.9 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.

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PART II

PLANNING CODE

CHAPTER 4

RESOURCE ADEQUACY CODE AND SYSTEM PLANNING CODE

4. Resource Adequacy Code

4.1 Introduction

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

4.2 Integrated Resource Planning

The integrated resource planning shall include:

(a) Demand forecasting;

(b) Generation resource adequacy planning; and

(c) Transmission resource adequacy planning.

4.3 Demand Forecasting and Generation Resource Adequacy Planning

4.3.1 The provisions related to demand assessment and forecasting and Generation Resource Adequacy Planning shall be governed by the provisions of Madhya Pradesh Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2024 and amendments thereof.

4.3.2 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.

4.4 Transmission Resource Adequacy Planning

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

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

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

4.5 System Planning Code

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

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

4.5.3 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:

(a) any Licensee or generating company on payment of the transmission charges; or

(b) 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.

4.5.4 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:

(a) any Licensee or generating company on payment of the transmission charges; or

(b) 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.

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

(i) Development on a User's system already connected to the State Transmission System.

(ii) The introduction of a new Connection point between the User's system and the State Transmission System.

(iii) Evacuation system for Generating Stations within or outside the State.

(iv) Reactive Compensation.

(v) A general increase in system capacity (due to addition of generation or system load) to remove operating constraints and maintain standards of security.

(vi) Transient or steady state stability considerations.

(vii) Cumulative effect of any of the above.

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

4.5.7 The Planning Code provides the following:

- Defines the procedure for the exchange of information between STU and User in respect of any proposed User development on the User's system, which may have an impact on the performance of the User.
- Details the information which STU shall make available to Users in order to facilitate the identification and evaluation of opportunities for use or connection to State Transmission System.
- Details the information required by STU from Users to enable STU to plan the development of its Transmission System to facilitate proposed User developments.
- Specifies planning and design standards, which will be applied by STU in planning and development of the power system.

4.6 Planning Policy

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

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

4.6.3 STU shall follow the following steps in planning:

(i) Based on the provisions of Resource Planning Code, Distribution Licensees shall provide the details of the Demand forecasting, Generation resource adequacy planning data, methodology and assumptions on which the forecasts are based, to the

Commission and STU. These forecasts would be annually reviewed and updated by Distribution Licensees.

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

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

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

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

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

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

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

4.7 Planning Responsibility

4.7.1 The primary responsibility of demand forecasting within Distribution Licensees' area of supply rests with MPPMCL / Distribution Licensees. MPPMCL / Distribution Licensees shall determine their peak demand and energy forecasts for each category for each of the succeeding five (5) years and submit the same annually by 31st May to STU along with details of the Demand forecasting, Generation resource adequacy planning, data, methodology and assumptions on which the forecasts are based along with their proposals for transmission system augmentation. The demand forecasts shall be updated annually or whenever major changes are made in the existing forecasts or planning.

4.7.2 State Sector Generating Stations (SSGS) shall provide their generation capacity to STU for evacuating power from their power stations for each of the succeeding five (5) years along

with their proposals for transmission system augmentation and submit the same annually by 31st March to STU.

4.7.3 STU shall obtain Renewable Capacity Addition plan issued by New and Renewable Energy Department, (MPNRED), Govt. of Madhya Pradesh.

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

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

4.7.6 Operation and Co-ordination Committee consisting of members from each DISCOMs, MPPMCL, STU and MPPGCL shall review and approve the demand forecasts and the methodology followed by MPPMCL for each of the DISCOMs.

4.8 Planning Data

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

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

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

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

(a) Standard Planning Data (Transmission) (**Appendix-A**)

(b) Detailed Planning Data (Transmission) (**Appendix-B**)

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

4.9 Implementation of Transmission Plan

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

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CHAPTER 5
CONNECTION CODE

5. Connection Code

5.1 Introduction

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

5.1.2 The connectivity to Intra-State Transmission System shall be granted by State Transmission Utility in accordance with the Grid Code, Madhya Pradesh Electricity Supply Code, 2021 and Madhya Pradesh Electricity Regulatory Commission (Recovery of expenses & other charges for providing electric line or plant used for the purpose of giving supply), Regulations, 2022 and amendments thereof.

5.1.3 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. Madhya Pradesh Electricity Regulatory Commission (Terms & Conditions for Intra-State Open Access in Madhya Pradesh), Regulations 2021 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;

In addition to above, all relevant Laws/Regulations/Guidelines/Rules/Standards with

amendments as specified from time to time shall be applicable for grant of connectivity.

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

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

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

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

5.2 Objective

The objective of this chapter is to ensure the following:

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

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

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

(iv) The ownership and responsibility for all items of equipment is clearly specified in a

schedule (Site Responsibility Schedule as **Appendix-G** of this Grid Code) for every site where a Connection is made.

5.3 Procedure for Connection Application

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

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

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

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

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

required under intimation to the Applicant/ User.

(vi) STU shall make a formal offer within sixty (60) days of the receipt of the application. The offer shall stipulate and take into account any works required for the extension or reinforcement of the State Transmission System necessitated by the applicant's proposal and for obtaining any consent necessary for the purpose. If the specified time limit for making the offer against any application is not adequate, STU shall make a preliminary offer within the specified time indicating the extent of further time required for detailed analysis.

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

(viii) In the event of offer becoming invalid or not accepted by the Applicant, STU shall not consider the application from the same Applicant/ User within one hundred eighty (180) days, unless the new application is substantially different from the original application.

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

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

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

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

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

5.4 Change in Application

The Applicant/ User may apply for any changes in the application, such as change in location of the Generating Plant, Captive Power Plant or facility of Distribution Licensee or HT / EHT consumer of Distribution Licensee, point of injection or drawal, change required in quantum of injection of power, change in load demand, change in voltage level of connectivity, etc., which shall be allowed once,by STU before the issuance of connectivity offer. Once the initial offer is approved, except minor typographical error, which does not require any substantial technical changes or leads to further feasibility study, no change in

the application will be entertained and in other cases seeking substantial changes, the initial offer of connectivity shall be treated as cancelled and Applicant shall have to furnish a fresh application for connectivity to STU with the required changes.

5.5 Processing of Application

Notwithstanding anything contained in this Code, the applications shall be processed in the following manner:

(i) STU shall carry out system studies including load flow, short circuit and other relevant studies, if necessary, and decide the point of connection and requirement of system strengthening of Intra-State Transmission System, if any, which may be augmentation, renovation, modernization of existing system or transmission lines. While undertaking the above exercise, STU shall:

(a) Undertake study for grant of connectivity.

(b) Undertake system feasibility studies and assess/ identify/ determine the system strengthening requirement on the basis of quantum of load/ generation or any other details given in the applications of connectivity.

(c) Undertake inter-connection studies of the Intra-State Transmission Licensees in accordance with CEA Technical Standards for Connectivity Regulations and amendments thereof.

(d) Require the Applicants/ Users/ Agencies connected to or to be connected as the case may be, with Intra-State Transmission System to furnish such data/ information as may be, considered appropriate by respective Intra-State Transmission Licensee for further studies and Applicants/ Users/ Agencies shall respond to such requirement within fifteen (15) days.

(e) Prepare preliminary report of system study, covering all aspects of MPEGC and communicate the same to the Applicant/ User and all concerned.

(f) Reconcile the preliminary report in relation to any change, material or otherwise, reported for incorporation in the scheme of connectivity with Intra-State Transmission System by the Applicant/ User.

(ii) Necessary co-ordination or consultation shall be established with Applicant/ User/ Agencies/ Long-Term or Medium-Term Customers connected to or to be connected as the case may be, with the Intra-State Transmission System to materialize the connectivity and other related issues.

(iii) Based on the results of preliminary report and consultation thereafter as mentioned

above, STU shall draw plan of connectivity in case of each applicant and optimize such plans, as may be considered necessary, which shall be grouped as under:

(a) Grant of Connectivity without system strengthening/ augmentation, or;

(b) Grant of connectivity with system strengthening/ augmentation.

(iv) In pursuance of plan made as above, each applicant except HT/ EHT consumer of the Distribution Licensees shall be required to make a request for grant of Open Access (OA) for use of Intra-State Transmission System of Transmission Licensees of the State in accordance with MPERC (Terms & Conditions for Intra-State Open Access in Madhya Pradesh), Regulations 2021 and amendments thereof.

(v) After completion of process as aforesaid, STU will formalize the Point of Connectivity and requirement of inter-connection facilities of the applicant. While formalizing the connectivity conditions, STU shall ensure to fix the timelines necessary for execution of any segment of system strengthening requirement considered necessary for energization of point of connectivity and operationalization of Open Access thereof. System strengthening requirements shall clearly identify expansion, augmentation, renovation, modernization of existing Sub-stations and / or electric lines and / or construction of new Sub-stations or transmission lines.

5.6 Connectivity Conditions

The procedure for connectivity with the Intra-State Transmission System is further sub-divided into the following four (4) categories:

5.6.1 **Connectivity of Generator/ Captive Generator/ Open Access Customer with MPPTCL Transmission Network**

a) For connectivity of generator/ captive generator or any Open Access customer with MPPTCL system, construction of necessary feeder bays and other works such as installation of terminal equipment associated with transformation capacity enhancement/ voltage upgradations works/ creation of new voltage level in existing sub-station/ new voltage expansion (addition of transformation capacity), which results in addition of transformer(s) in MPPTCL's sub-station for termination of the dedicated lines of Applicant/ User, system strengthening shall be carried out by MPPTCL at the cost of Applicant/ Users. Upon completion, these feeder bays and other works shall be handed over to MPPTCL and will be operated and maintained by MPPTCL.

b) The O&M charges of such feeder bays and other works shall be recovered by Licensee in accordance with prevailing Regulations and policies through ARR/tariff, duly

approved by the Commission.

c) The dedicated transmission line, if any, required for connectivity of Applicant/ User with MPPTCL transmission system may be either constructed by MPPTCL/ Distribution Licensees or by Applicant/ User under the supervision of MPPTCL/ Distribution Companies. However, in either case, Applicant/ User will bear the cost of construction of such dedicated transmission line and after completion, the same shall be handed over to MPPTCL/ Distribution Licensees, as the case may be. The handed over assets will be operated and maintained by MPPTCL/Distribution Companies, as the case may be and the O&M charges of such lines shall be recovered by MPPTCL/ Distribution Companies in accordance with prevailing Regulations and policies through ARR/tariff, duly approved by the Commission.

d) The Generator/ Captive Generator may construct the dedicated transmission line at their own cost with the permission of Energy Department, GoMP under Section 68 as applicable and Section 164 of the Act. In such case, after completion, the dedicated transmission line shall be held as the assets of Generator/ Captive Generator and shall be operated and maintained by them at their own cost.

5.6.2 **Connectivity of HT/ EHT Consumer of Distribution Companies with MPPTCL Transmission Network**

a) For connectivity of HT/ EHT Consumer of Distribution Companies with MPPTCL system, construction of necessary feeder bays and other works such as installation of terminal equipment associated with transformation capacity enhancement/ voltage upgradations works/ creation of new voltage level in existing sub-station/ new voltage expansion (addition of transformation capacity), which results in addition of transformer(s) in MPPTCL's sub-station for termination of dedicated lines of Applicant/ User, system strengthening shall be carried out by MPPTCL at the cost of HT/ EHT Consumer of Distribution Companies. Upon completion, these feeder bays and other works shall be handed over to MPPTCL and will be operated and maintained by MPPTCL.

b) The O&M charges of such feeder bays and other works shall be recovered by Licensee in accordance with prevailing Regulations and policies through ARR/tariff, duly approved by the Commission.

c) The dedicated transmission line, if any required for connectivity of Applicant/ User with MPPTCL transmission system may be either constructed by MPPTCL/ Distribution

Licensees or by Applicant/ User under the supervision of MPPTCL/ Distribution Companies. However, in either case, Applicant/ User will bear the cost of construction of such dedicated transmission line and after completion, the same shall be handed over to MPPTCL/ Distribution Licensees, as the case may be. The handed over assets will be operated and maintained by MPPTCL/Distribution Companies, as the case may be and the O&M charges of such lines shall be recovered by MPPTCL/ Distribution Companies in accordance with prevailing Regulations and policies through ARR/tariff, duly approved by the Commission.

5.6.3 **Connectivity of Generator/ Captive Generator/ Open Access Customer with Transmission Network of Transmission Licensees other than MPPTCL**

a) For connectivity of Generator/ Captive Generator or any other Open Access customer with Intra-State Transmission Licensees other than MPPTCL, construction of necessary feeder bays and other works such as installation of terminal equipment associated with transformation capacity enhancement/ voltage upgradations works/ creation of new voltage level in existing sub-station/ new voltage expansion (addition of transformation capacity), which results in addition of transformer(s) in the sub-station of Intra-State Transmission Licensees other than MPPTCL for termination of the dedicated lines of Applicant/ User, system strengthening shall be carried out by Intra-State Transmission Licensees other than MPPTCL or by Applicant/ User as the case may be, mutually agreed upon as per relevant rules and regulations laid down for the purpose. Upon completion, these feeder bays and other works shall be operated and maintained by respective Intra-State Transmission Licensees as per agreed terms and conditions.

b) The O&M charges of such feeder bays and other works may be recovered by Licensee in accordance with prevailing Regulations, duly approved by the Commission.

c) A copy of MoU between respective Transmission Licensee and Applicant/ User need be submitted to STU, MPPMCL and SLDC.

d) The dedicated transmission line, if any, required for connectivity of Applicant/ User with transmission network of Intra-State Transmission Licensees other than MPPTCL may be either constructed by MPPTCL/ Distribution Licensees or by Applicant/ User under the supervision of MPPTCL/ Distribution Companies. However, in either case, Applicant/ User will bear the cost of construction of such dedicated transmission line and after completion, the same shall be handed over to MPPTCL/ Distribution Licensees, as the case may be. The handed over assets will be operated and maintained

by MPPTCL/Distribution Companies, as the case may be and the O&M charges of such lines shall be recovered by MPPTCL/ Distribution Companies in accordance with prevailing Regulations and policies through ARR/tariff, duly approved by the Commission.

e) The Generator/ Captive Generator may construct the dedicated transmission line at their own cost with the permission of Energy Department, GoMP under Section 68 as applicable and Section 164 of the Act. In such case, after completion, the dedicated transmission line shall be held as the assets of Generator/ Captive Generator and will be operated and maintained by them at their own cost.

5.6.4 **Connectivity of HT/ EHT Consumer of Distribution Companies with Transmission Network of Transmission Licensees other than MPPTCL**

a) For the connectivity of HT/ EHT consumer of Distribution Licensee with Intra-State Transmission Licensees other than MPPTCL, construction of necessary feeder bays and other works such as installation of terminal equipment associated with transformation capacity enhancement/ voltage upgradations works/ creation of new voltage level in existing sub-station/ new voltage expansion (addition of transformation capacity), which results in addition of transformer(s) in the sub-station of Intra-State Transmission Licensees other than MPPTCL for termination of the dedicated lines of Applicant/ User, system strengthening shall be carried out by respective Intra-State Transmission Licensees other than MPPTCL or by Applicant/ User as may be mutually agreed upon as per Rules and Regulations laid down for the purpose. Upon completion, these feeder bays and other works shall be operated and maintained by respective Intra-State Transmission Licensees as per agreed terms and conditions.

b) The O&M charges of such feeder bays and other works may be recovered by Licensee in accordance with prevailing Regulations, duly approved by the Commission.

c) A copy of MoU between respective Transmission Licensee and Applicant/ User needs be submitted to STU, MPPMCL, SLDC and concerned Distribution Licensee.

d) The dedicated transmission line, if any, required for connectivity of Applicant/ User with transmission network of Intra-State Transmission Licensees other than MPPTCL may be either constructed by MPPTCL/ Distribution Licensees or by Applicant/ User under the supervision of MPPTCL/ Distribution Companies. However, in either case, Applicant/ User will bear the cost of construction of such dedicated transmission line and after completion, the same shall be handed over to MPPTCL/ Distribution

Licensees, as the case may be. The handed over assets will be operated and maintained by MPPTCL/Distribution Companies, as the case may be, and the O&M charges of such lines shall be recovered by MPPTCL/ Distribution Companies in accordance with prevailing Regulations and policies through ARR/tariff, duly approved by the Commission.

5.7 Connection Agreement

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

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

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

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

(d) Diagram of electrical system to be connected.

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

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

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

5.7.2 The Connection Agreement shall be executed between the following parties:

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

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

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

(iv) In case of Generating Company/ Captive Generator or any Open Access customer seeking connectivity from sub-station of Intra-State Transmission Licensees other than MPPTCL at voltage level of 132 kV and above, the agreement will be executed between Applicant, STU and respective Intra-State Transmission Licensee.

(v) In case of Generating Company/ Captive Generator or any Open Access customer

seeking connectivity from sub-station of Intra-State Transmission Licensees other than MPPTCL at voltage level of 33 kV, the agreement will be executed between Applicant, STU, respective Intra-State Transmission Licensee and concerned Distribution Licensee, as the case may be.

(vi) In case of HT/ EHT consumer of Distribution Licensee seeking connectivity from sub-station of Intra-State Transmission Licensees other than MPPTCL at voltage level of 33 kV and above, the agreement will be executed between Applicant, STU, respective Intra-State Transmission Licensee and concerned Distribution Licensee, as the case may be.

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

5.8 Responsibilities for operational safety

5.8.1 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.

5.8.2 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.

5.8.3 **Single Line Diagrams**

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

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

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

5.8.4 **Site Common Drawings**

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

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

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

5.9 System Performance

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

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

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

5.9.4 STU and SLDC shall jointly carry out a system study six (6) months before the expected date of first energization of a new power system element to identify operational constraints, if any. In case of constraints, STU and SLDC shall identify measures for facilitating the integration of the element, subject to grid security.

5.9.5 SSGS 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.

5.9.6 The frequency shall always remain within the band as specified in IEGC/ MPEGC.

5.9.7 The User shall however, be subject to the grid discipline of SLDC/WRLDC as per guidelines mutually agreed with WRPC/WRLDC.

5.9.8 The variation of voltage at the inter-connection point may not be more than the limit specified in **Regulation 10.6** 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 in Transmission Performance Standards.

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

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

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

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

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

5.9.12 Detailed Performance Standards and its compliance requirements have been stated separately in the document namely MPERC (Transmission Performance Standards), Regulations, 2022 and amendments thereof.

5.10 Equipment of Users/ State Transmission System at Connection Points

5.10.1 **Sub-station Equipment:**

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

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

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

5.10.2 **Fault Clearance Time** (basic step operation time, i.e., Zone 1 time): The fault clearance time of the equipment directly connected to the Intra-State Transmission System shall be as per the CEA Technical Standards for Construction Regulations and amendments thereof.

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

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

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

5.11 Generating Units and Power Stations

5.11.1 A Generating Unit shall be capable of continuously supplying its normal rated active/ reactive output within the system frequency and voltage variation range indicated in **Chapter 10** of the Grid Code, subject to the design limitations specified by the manufacturer.

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

5.12 Reactive Power Compensation

5.12.1 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.

5.12.2 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.

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

5.13 Communication Facilities

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

5.13.2 All Users and Intra-State Transmission Licensees shall provide parameter such as flow, voltage and status of switches/ transformer taps, etc., in line with interface requirements and

other guideline made available by SLDC.

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

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

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

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

5.14 System Recording Instruments

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

5.15 Procedure for Site Access, Site operational activities and Maintenance Standards

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

5.16 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.

5.17 Connection Point

5.17.1 State Sector Generating Station (SSGS) Voltage may be 400/220/132 kV or as agreed with STU. Unless specifically agreed with STU, the Connection point shall be the outgoing feeder gantry of Power Station Switchyard.

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

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

5.18 Distribution Licensee

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

5.18.2 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.

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

5.19 IPPs, CGPs, EHV Consumers and Open Access Users

Voltage may be 220/132kV 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.

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

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

5.21 Commissioning of Connectivity

5.21.1 The commissioning of all the new projects shall be governed as per **Chapter 7** of the Grid Code.

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

5.21.3 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.

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

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

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

5.22 Post Connectivity Events

5.22.1 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.

5.22.2 Post connectivity events shall be undertaken in accordance with this Grid Code and relevant Regulations of CEA/ Commission/ CERC 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.

5.23 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.

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CHAPTER 6

SYSTEM SECURITY CODE

6. System Security Code

6.1 Introduction

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

6.2 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 integrated part of Western Regional Grid. 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.

6.3 System Security Aspects

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

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

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

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

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

(c) For safety of Human Life;

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

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

Any such isolation shall be reported to SLDC within 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 the real time. No User of the Grid is allowed to perform any switching operation by their own. The restoration process shall be supervised by SLDC.

All operational instructions given by RLDC 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.

6.3.4 SLDC, in consultation with WRPC, Users and respective RLDC, 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.

6.3.5 An important element of the State Grid as listed at **Regulation 6.3.4** 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 RLDC / NLDC/ WRPC and the concerned regional entities, who are likely to be affected, as specified in the Detailed Operating Procedure of NLDC or RLDC or SLDC.

6.3.6 In case of switching off or tripping of any of the important elements of the State Grid under emergency conditions or otherwise, it shall be intimated immediately by the Users with available details to SLDC, if the element is within the control area of SLDC, who in turn shall intimate the concerned RLDC. The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within half an hour. The SLDC and the Users shall ensure restoration of such elements within the estimated time of restoration, as intimated.

6.3.7 The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. The restoration process shall be supervised by SLDC, in coordination with concerned RLDC and NLDC in accordance with the system restoration procedures of NLDC or RLDC or SLDC.

6.3.8 Maintenance of grid elements shall be carried out by respective User in accordance with the provisions of the CEA Grid Standards Regulations and amendments thereof. Outage of an element that is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be monitored by SLDC. SLDC shall report such outages to RLDC/ WRPC. SLDC

shall also issue suitable instructions to restore such elements in a specified time period.

6.3.9 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.

6.3.10 The tuning of AVR, PSS, Voltage Controllers (PPC) including for low and high voltage ride through capability of wind and solar generators or any other requirement as per CEA Technical Standards for Connectivity shall be carried out by the respective generating station:

- at least once every five (5) years;
- based on operational feedback provided by SLDC, after analysis of a grid event or disturbance;
- in case of major network changes or fault level changes near the generating station as reported by SLDC; and
- in case of a major change in the excitation system of the generating station.

6.3.11 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 WRPC/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.

6.3.12 SLDC 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.

6.3.13 Mock drill of the islanding schemes shall be carried out annually by SLDC in coordination with respective RLDC and other Users involved in the islanding scheme. In case mock drill with field testing is not possible to be carried out for a particular scheme, simulation testing shall be carried out by SLDC.

6.3.14 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 WRPC from time to time. The default UFR settings shall be as specified in Table below or as amended in IEGC from time to time:

Sr. No.	Stage of UFR Operation	Frequency (Hz)
1.	Stage-1	49.40
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 WRPC.		
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 WRPC to Madhya Pradesh.

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

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

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

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

(d) SLDC shall ensure that telemetered data of feeders (MW power flow in real time and circuit breaker status) on which UFR and df/dt relays are installed is available at its control centre. SLDC shall monitor the combined load in MW of these feeders at all times. SLDC shall share the above data with respective RLDC in real time and submit a monthly exception report to respective RPC. SLDC shall inform respective RLDC as well as respective RPC 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 respective RLDC and RPC, failing which suitable action may be initiated by respective RPC.

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

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

6.3.16 SLDC, STU or Users may identify the requirement of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system within operating limits and to protect against situations such as voltage collapse, cascade tripping and tripping of important corridors/flow-gates. Any such SPS at the intra-regional level shall be finalized by the SLDC/WRPC. 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 WRLDC.

6.3.17 SLDC and Users shall operate in a manner to ensure that the steady state grid voltage as per CEA Grid Standards Regulations and amendments thereof remains within the following operating range:

Voltage (kV rms)		
Nominal	**Maximum**	**Minimum**
765	800	728
400	420	380
230*	245*	207*
220	245	198
132	145	122
110	121	99
33	36	30

** As per CEA Manual on Transmission Planning Criteria and subsequent updations.*

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

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

6.3.20 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.

6.3.21 The 132 kV and above transmission lines and ICTs shall not be deliberately opened or removed from service at any time except when advised by SLDC or with specific and prior clearance of SLDC. Where prior clearance from SLDC is not possible, it should be intimated to SLDC at the earliest possible time after the incident.

6.3.22 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.

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

6.3.24 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.

6.3.25 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.

6.4 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. 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 VAr 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.

6.5 Management of RE Curtailment

I) Grid Security Parameters

The following conditions are specified as Grid Security Parameters to ascertain the boundary conditions, breaching of which could potentially affect reliable and safe grid operations and hence, warranting appropriate actions on part of SLDC to initiate RE curtailment, as under:

Sr. No.	Parameter	Specific Conditions
1	Operating Frequency band	Average frequency for two or more successive time-blocks exceeds 50.05 Hz
2	State Volume Limit as per CERC DSM Regulations	Under-drawal by State at State periphery outside the range of 200 MW for two or more successive time blocks.
3	Technical Minimum Margin for TPS % of MCR or Installed Capacity	In case all intra-State thermal generating stations are operating at technical minimum and no further limit for backing down any thermal generation unit exists.
4	Thermal limit of Transmission lines	Permissible maximum Loading limit on transmission line shall be its thermal loading limit as stipulated under CEA Manual on transmission planning criteria and updated thereof.
5	Transformer/ICT loading limits	Loading limit for Inter-connecting transformer (ICT) shall be its Name plate Rating as stipulated under CEA Manual on transmission planning criteria and updated thereof.
6	Operational voltage limits.	The steady state operating voltage limits under Normal conditions shall be within operating range as specified in CEA Grid Standards Regulations and amendments thereof.

In case of breach of any of the boundary conditions as outlined in respect of above grid parameters and if SLDC is of the opinion that the continued injection of variable renewable power would further worsen the situation and affect reliable and safe grid operations, SLDC may instruct the solar/ wind generator to back down generation on consideration of grid security or to ensure safety of any equipment or to ensure that no personnel is endangered and Solar/ wind generator shall comply with the same. In case of curtailment of solar/ wind generation, the protocol for curtailment as specified below shall be followed:

Provided that SLDC shall publish a report on RE curtailment along with reasons thereof, on its website.

II) Protocol for curtailment

a) Management of Curtailment for Frequency Management

i. In case frequency exceeds the over-frequency limit, SLDC is expected to back-

down the hydro generation [except for constrained hydro generation projects such as run-of-river hydro projects, irrigation linked hydro generation projects or storage hydro factoring spillage considerations] followed by thermal generation to technical minimum (as per MOD) considering the scheduled demand in subsequent time blocks and ramp up/ramp down requirement to meet the scheduled demand.

ii. SLDC may instruct DISCOMs / MPPMCL to reduce the requisition from their contracted Inter-State Generating Stations (ISGS) through revision of schedules. Also, DISCOMs /MPPMCL may be advised to withdraw demand curtailments, if any, issued.

iii. SLDC may request RLDC for backing down the inter-State generation schedule to State.

iv. SLDC shall instruct the Pump Storage Hydro Projects to operate in Pumped mode subject to capacity constraint and spillage considerations to provide the load to the system for reduction of the frequency.

v. If hydro generation (excluding run-of-river) is in operation, SLDC shall reduce or stop the hydro generation to provide required relief considering its higher ramp down rate and avoiding the wastage of water resources.

vi. Besides implementing all the above measures, if the necessary relief is not achieved and frequency continues to rise beyond the upper limit of 50.05 Hz for two or more consecutive time-blocks, SLDC may instruct the Pooling Sub Stations (PSS) to back down or curtail the renewable generation as last option for maintaining the frequency within limits.

vii. While curtailing for the purpose of frequency management, SLDC would ensure to avail required relief with minimum curtailment. In such instances, curtailment instructions shall be given to all PSSs on pro-rata basis of 'Available Capacity', for the time-block immediately prior to issuance of curtailment instructions.

b) Curtailment for relief from Transmission Congestion

i. No Transmission Line outage shall be availed without the approval from SLDC. Also, no planned outages of Transmission Line shall be considered if not submitted at least two (2) days prior to the date of Outage.

ii. The incidences resulting in curtailment of Wind/Solar Generation, which shall be intimated to SLDC are as follows:

- Planned / Forced Outages on evacuation infrastructure,
- Tripping of any transmission elements/evacuation infrastructure,
- Overloading of any transmission elements/evacuation infrastructure.

iii. In case of tripping of any transmission element/evacuation infrastructure/PSS resulting in curtailment/backing down of renewable generation, it shall be the responsibility of concerned Transmission Licensee and affected renewable Generator(s) (for their respective Pooling Sub-Stations) through their Lead Generator or separately to intimate the same immediately to SLDC for required modifications in the schedules along with tentative time for restoration.

iv. In case of planned outages, the Transmission Licensee shall plan the outage period so as to avoid curtailment of Wind/Solar generation.

v. All the events of Planned/Forced Outages of Transmission Lines resulting in the backing down/curtailment of Wind and Solar Generation shall be submitted to SLDC, which would cover information about event duration, affected location(s) of grid elements, renewable capacity, cause of outage, likely restoration / rectification time.

vi. In case of any bottleneck in the Intra-State Transmission network, SLDC is required to initiate the load relief on the specific transmission lines connected to Wind/Solar Pooling Sub-Station (PSS). SLDC may issue instructions to PSS to back down/curtail the renewable generation to that extent in order to seek desired relief in the best interest of grid operations.

vii. While curtailing to mitigate the congestion, SLDC would target the specific PSS to get required load relief with minimum curtailment. However, SLDC shall also ensure that, the same PSS are not receiving frequent curtailments. In such cases, curtailment instructions may be given on pro-rata basis of 'available capacity' at PSS in that area, for the time-block immediately prior to issuance of curtailment instructions.

c) Maintaining the Volume Limits at State Periphery

i. CERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 have specified the volume limits (+/- 200 MW) for renewable rich States for deviation of drawal from the schedule at the State periphery. SLDC is mandated to take all measures to maintain the State drawal within the Volume Limits specified by CERC.

ii. SLDC may initiate the Backing down or Curtailment in case under-drawal of State is beyond the Volume Limit at the State periphery. SLDC shall also take into consideration the grid frequency, while acting on the volume limits as given in table below:

Curtailment for maintaining Volume Limit (Under-drawal) at State Periphery		
Frequency in Hz	**For Deviation <= 200 MW (or threshold limit as specified)**	**For Deviation > 200 MW (or threshold limit as specified)**
F < 49.90 Hz	No	No
F >49.90 and < 50.05 Hz	No	Yes
F > 50.05 Hz	Yes (Provided Grid Frequency exceeds 50.05 Hz for two or more successive time blocks.)	Yes (Provided Under-drawal by State at state periphery is outside the range of 200 MW for two or more successive time-blocks.)

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CHAPTER 7

COMMISSIONING AND COMMERCIAL OPERATION CODE

7. Commissioning and Commercial Operation Code

7.1 Introduction

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

7.2 Drawal of Start Up Power and Injection of Infirm Power

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

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

7.2.2 The period for which such inter-change shall be allowed shall be as follows: -

(a) Drawal of start-up power shall not exceed 15 months prior to the expected date of first synchronization and one year after the date of first synchronization; and

(b) Injection of infirm power shall not exceed one year from the date of first synchronization.

7.2.3 Notwithstanding the provisions of the above **Regulation 7.2.2**, the Commission may allow extension of the period for inter-change of power beyond the stipulated period on an application made by the generating station at least two months in advance of the completion of the stipulated period.

7.2.4 Drawal of start-up power shall be subject to payment of transmission charges as per the MPERC (Terms & Conditions for Determination of Transmission Tariff) Regulations and amendments thereof.

7.2.5 The charges for deviation for drawal of start-up power or for injection of infirm power shall be as per Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 and amendments thereof till the time no separate Regulations/ order/ notification is issued by the Commission in the above said matter.

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

7.2.7 The onus of proving that the interchange of infirm power from the unit(s) of the generating station is for the purpose of pre-commissioning activities, testing and commissioning, shall

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

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

7.2.9 SLDC shall stop the drawal of the start-up Power in the following events:

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

(b) In the case of default in payment of monthly transmission charges, charges under Madhya Pradesh Electricity Regulatory Commission (Levy and Collection of Fee and charges by State Load Despatch Centre) Regulations, 2004 and deviation charges under Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and its subsequent amendments.

7.3 Data to be furnished prior to notice of Trial Run

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

Description	Units
Installed Capacity of generating station	MW
Installed Capacity of generating station	MVA
MCR	MW
Number x unit size	No x MW
Time required for cold start	Minute
Time required for warm start	minute
Time required for hot start	Minute
Time required for combined cycle operation under cold conditions	Minute
Time required for combined cycle operation under warm conditions	Minute
Ramping up capability	% per minute

Description	Units
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

7.4 Notice of Trial Run

7.4.1 The generating company proposing its generating station or a unit thereof for trial run or repeat of trial run shall give a notice of not less than seven (7) days to SLDC, STU and the beneficiaries of the generating stations, including intermediary procurers, wherever identified:

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

7.4.2 The Transmission Licensee proposing its transmission system or an element thereof for trial run shall give a notice of not less than seven days to the SLDC, STU, Distribution Licensees of the State and the owner of the inter-connecting system.

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

7.4.4 A generating station shall be required to undergo a trial run in accordance with the below mentioned **Regulation 7.5** after completion of Renovation and Modernization for extension of the useful life of the project as per the Tariff Regulations.

7.5 Trial Run of Generating Unit

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

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

Provided that:

(i) short interruption or load reduction shall be permissible with the corresponding increase in duration of the test;

(ii) interruption or partial loading may be allowed with the condition that the average load during the duration of the trial run shall not be less than MCR, excluding the period of interruption but including the corresponding extended period;

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

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

7.5.2 **Trial Run of Hydro Generating Unit shall be carried out in accordance with the following provisions:**

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

Provided that -

(i) short interruption or load reduction shall be permissible with a corresponding increase in duration of the test;

(ii) interruption or partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period;

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

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

Provided that if such a generating station is not able to demonstrate the MCR when sufficient water is available, the generating company shall de-rate the capacity in terms of below mentioned **Regulation 7.5.2(b)** and such de-rating shall be effective from COD.

(b) Where, on the basis of the trial run, a hydro generating unit fails to demonstrate the unit capacity corresponding to MCR, the Generating Company shall have the option to either

de-rate the capacity or go for a repeat trial run. If the Generating Company decides to de-rate the unit capacity, the de-rated capacity in such cases shall not be more than 90% of the demonstrated capacity to cater for primary response.

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

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

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

Successful trial run of a solar inverter unit(s) covered under the above **Regulation 7.5.3(a)** shall mean the flow of power and communication signal for not less than four hours on a cumulative basis between sunrise and sunset in a single day with the requisite metering system, power plant controller, telemetry and protection system in service. The Generating Company shall record the output of the unit(s) during the trial run and shall corroborate its performance with the temperature and solar irradiation recorded at site during the day and plant design parameters:

Provided that:

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

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

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient solar irradiation is available after COD, the generating company shall de-rate the capacity in terms of below mentioned **Regulation 7.5.3(f)**.

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

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

Successful trial run of a wind turbine(s) covered under the above **Regulation 7.5.3(b)** shall mean the flow of power and communication signal for a period of not less than

continuous four (4) hours during periods of wind availability with the requisite metering system, power plant controller, telemetry, and protection system in service. The Generating Company shall record the output of the unit(s) during the trial run and corroborate its performance with the wind speed recorded at the site(s) during the day and plant design parameters:

Provided that-

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

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

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient wind velocity is available after COD, the Generating Company shall de-rate the capacity in terms of below mentioned **Regulation 7.5.3(f)**.

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

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

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

(f) Where, on the basis of the trial run, solar/ wind/ ESS/ PSP/ hybrid generating station connected at State Transmission system fails to demonstrate its rated capacity, the Generating Company shall have the option to either go for a repeat trial run or de-rate the capacity subject to a minimum aggregated de-rated capacity of 5 MW and above, as the case may be.

(g) Notwithstanding the provisions contained in the Grid Code, where Power Purchase

Agreement provides for a specific capacity that can be declared COD, trial run shall be allowed for such capacity in terms of such Power Purchase Agreement.

7.6 Trial Run of Intra-State Transmission System

Trial run of a transmission system or an element thereof shall mean successful energisation of the transmission system or the element thereof at its nominal system voltage through inter-connection with the grid for a continuous twenty-four (24) hours flow of power and communication signal from the sending end to the receiving end and with the requisite metering system, telemetry and protection system:

Provided that under exceptional circumstances and with the prior approval of STU and SLDC, a transmission element can be energized at lower nominal system voltage level:

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

7.7 Documents and Tests Prior to Declaration of Commercial Operation

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

7.7.2 All thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW shall submit documents confirming the enablement of automatic operation of the plant from the appropriate Load Despatch Centre by integrating the controls and tele-metering features of their system into the automatic generation control in accordance with CEA Technical Standards for Construction Regulations and CEA Technical Standards for Connectivity Regulations and amendments thereof.

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

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

(i) Start-up curve for boiler and turbine including starting time of unit in cold, warm and hot conditions,

(ii) capability curve of generator,

(iii) design ramp rate of boiler and turbine.

(b) The following tests shall be performed:

(i) Operation at a load of fifty-five (55) percent of MCR as per the CEA Technical Standards for Construction Regulations for a sustained period of four (4) hours.

(ii) Ramp-up from Fifty-five (55) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute, in one step or two steps (with stabilization period of 30 minutes between two steps), and sustained operation at MCR for one (1) hour.

(iii) Demonstrate overload capability with the valve wide open as per the CEA Technical Standards for Construction Regulations and sustained operation at that level for at least five (5) minutes.

(iv) Ramp-down from MCR to fifty-five (55) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute, in one or two steps (with stabilization period of 30 minutes between two steps).

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

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

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

(a) The Generating Company shall submit documents from the OEM for the turbine characteristics curve indicating the operating zone(s) and forbidden zone(s). In order to demonstrate the operating flexibility of the generating unit, it shall be operated below and above the forbidden zone(s).

(b) The following tests shall be performed considering the water availability and head:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability, wherever feasible.

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

7.7.5 **Documents and Test Required for Gas Turbine based Generating Stations:**

(a) The Generating Company shall submit documents from the OEM for (i) starting time of

the unit in cold, warm and conditions (ii) design ramp rate.

(b) The following tests shall be performed:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability up to 100 MW capacity, wherever feasible.

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

7.7.6 **Documents and Tests Required for the Generating Stations based on wind and solar resources:**

(a) The Generating Company shall submit a certificate confirming compliance with CEA Technical Standards for Connectivity Regulations, in accordance with **Regulation 7.9.4** of the Grid Code.

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

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

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

(ii) Reactive power capability as per OEM rating at the available irradiance or the wind energy, as the case may be:

Provided that the Generating Company may submit offline simulation studies for the specified tests, in case testing is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD.

7.7.7 **Documents and Tests Required for Energy Storage Systems:**

(a) The ESS shall submit a certificate confirming compliance with the CEA Technical Standards for Connectivity Regulations, in accordance with **Regulation 7.9.4** of the Grid Code.

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

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

(ii) Frequency response of ESS.

(iii) Ramping capability as per design.

7.7.8 **Documents and Tests Required for HVDC Transmission System:**

(a) The Transmission Licensee shall submit technical details including operating guidelines such as filter bank requirements at various operating loads and monopolar/ or bipolar configuration, reactive power controller, run-back features, frequency controller, reduced voltage mode of operation, circuit design parameters and power oscillation damping, as applicable.

(b) The following tests shall be performed:

(i) Minimum load operation.

(ii) Ramp rate.

(iii) Overload capability, subject to grid condition.

(iv) Black start capability in the case of Voltage Source Convertor (VSC) HVDC, wherever feasible.

(v) Dynamic Reactive Power Support (in the case of VSC based HVDC).

7.7.9 **Documents and Tests Required for SVC or STATCOM:**

(a) The Transmission Licensee shall submit technical particulars including a single line diagram, V/I characteristics, the rating of coupling transformer, the rating of each VSC, MSR and MSC branch, different operating modes, the IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not, then reasons for the same) and the results of an offline simulation-based study to validate the performance of POD.

(b) The following tests shall be performed to validate the full reactive power capability of SVC and STATCOM in both directions, i.e., absorption as well as injection mode:

(i) POD performance test;

(ii) dynamic performance testing:

Provided that the Transmission Licensee may submit offline simulation studies for the specified tests, in case the conduct of tests is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD.

7.8 Certificate of Successful Trial Run

7.8.1 In case any objection is raised by a beneficiary in writing to the SLDC with a copy to all concerned regarding the trial run within two (2) days of completion of such trial run, the SLDC shall, within five (5) days of receipt of such objection, in coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or if there is a

need for a repeat trial run.

7.8.2 After completion of a successful trial run and receipt of documents and test reports as per **Regulation 7.7** of the Grid Code, the SLDC shall issue a certificate to that effect to the concerned generating station, ESS, or Transmission Licensee, as the case may be, with a copy to their respective beneficiary(ies) and the STU and RPC, within three days.

7.9 Declaration by Generating Company and Transmission Licensee

7.9.1 **Thermal Generating Station**

(a) The Generating Company shall certify that:

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

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

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

(b) The certificates required under the above **Regulation 7.9.1(a)** shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the Generating Company and shall be submitted to the SLDC and to the Member Secretary of the concerned RPC before the declaration of COD.

7.9.2 **Hydro Generating Station**

(a) The Generating Company shall certify that:

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

(ii) The main plant equipment and auxiliary systems including the drainage de-

watering system, primary and secondary cooling system, LP and HP air compressor and firefighting system have been commissioned and are capable of full load operation of units on a sustained basis.

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

(b) The certificates required under the above **Regulation 7.9.2(a)** shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the Generating Company and shall be submitted to the SLDC and to the Member Secretary of the concerned RPC before the declaration of COD.

7.9.3 **Transmission system**

The Transmission Licensee shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD of the Company to the concerned SLDC and to the STU before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction Regulations, CEA Technical Standards for Connectivity Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations and this Grid Code and are capable of operation to their full capacity.

7.9.4 **Wind, Solar, Storage and Hybrid Generating Stations**

The generating station based on wind and solar resources, ESS, and hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the SLDC and to the STU before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity Regulations, CEA Technical Standards for Communication Regulations, CEA Safety Regulations and this Grid Code.

7.10 Commercial Operation Date (COD)

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

(a) Thermal Generating Station or a unit thereof

(i) The commercial operation date in the case of a unit of the thermal generation station shall be the date declared by the Generating Company after a successful trial run at

MCR or de-rated capacity as per **Regulation 7.5.1(b)** of the Grid Code, as the case may be, and submission of a declaration as per **Regulation 7.9.1** of the Grid Code.

(ii) In the case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station.

(b) Hydro Generating Station

(i) The commercial operation date in the case of a unit of the hydro generating station including a pumped storage hydro generating station shall be the date declared by the generating station after a successful trial run at MCR or de-rated capacity as per **Regulation 7.5.2(b)** of the Grid Code, as the case may be, and submission of a declaration as per **Regulation 7.9.2** of the Grid Code.

(ii) In the case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station.

(c) Transmission System

(i) The commercial operation date in the case of an Intra-State Transmission System or an element thereof shall be the date declared by the Transmission Licensee on which the Transmission System or an element thereof is in regular service at 0000 hours after successful trial operation for transmitting electricity and communication signals from the sending end to the receiving end as per **Regulation 7.6** of the Grid Code and submission of a declaration as per **Regulation 7.9.3** of the Grid Code:

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

Provided further that where only some of the transmission elements of the transmission system have achieved a successful trial run 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.

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

Provided that in case any transmission element is required in the interest of the power system as certified by the STU 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.

(d) Communication System

Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the Transmission Licensee from 0000 hours of which a communication system or element thereof shall be put into service after completion of the site acceptance test including transfer of voice and data to the respective control centres as certified by State Load Despatch Centre.

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

(i) The commercial operation date in the case of units of a renewable generating station aggregating to 5 MW and above or such other limit as specified in **Regulation 7.5.3** of the Grid Code, shall mean the date declared by the generating station after undergoing a successful trial run as per **Regulation 7.5.3** of the Grid Code, submission of declaration as per **Regulation 7.9.4** of the Grid Code, and subject to fulfilment of other conditions, if any, as per PPA.

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

7.10.2 Scheduling of the generating station or unit thereof shall start from 0000 hours of D+2 (where D is the Commercial Operation Date of the said generating station or unit thereof).

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PART III

LOAD DESPATCH & SYSTEM OPERATION CODE

CHAPTER 8

OPERATIONAL PLANNING CODE

8. Operational Planning

8.1 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.

8.2 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.

8.3 OPERATING PHILOSOPHY

8.3.1 All Intra-State Users shall at all times function in coordination to ensure integrity, stability and resilience of the grid and achieve economy and efficiency in the operation of power system.

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

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

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

8.3.5 Every generating station and transmission sub-station of 132 kV and above shall have a control room manned by qualified operating personnel round the clock. Alternatively, the same may be operated round the clock from a remotely located control room, subject to the condition that such remote operation does not result in a delay in the execution of any switching instructions and information flow:

Provided that a Transmission Licensee owning a transmission line but not owning the connected sub-station, shall have a coordination centre functioning round the clock, manned by qualified personnel for operational coordination with SLDC and equipped to carry out the operations as directed by SLDC.

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

coordination centres functioning round the clock and manned by qualified personnel for operational coordination with SLDC.

8.4 Demand Estimation

The demand estimation shall be done by the DISCOMs/MPPMCL in accordance with the provisions of **Chapter 4** of the Grid Code. SLDC/STU shall be provided with a copy of the same as and when it is finalized.

8.5 Demand Control

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

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

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

8.5.3 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.

8.5.4 SLDC shall advice STU for planning of automatic load shedding and rotational load shedding schemes through installation of Under Frequency Relays and df/dt relays.

8.5.5 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).

8.5.6 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.

8.5.7 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 WRLDC/ WRPC.

8.6 Demand Dis-connection

(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 8.6 (a)** and **Regulation 8.6 (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 respective RLDC may direct SLDC to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon by Users/ Distribution Licensees.

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

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

(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 respective RLDC/SLDC.

8.7 Load Crash

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

(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.

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

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CHAPTER 9

SCHEDULE AND DESPATCH CODE

9. Schedule and Despatch Code

9.1 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.

9.2 Objective

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

9.3 General Principles of Scheduling

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

Provided that from the date as may be notified by the Commission, the scheduling period may be revised to 288 time blocks, each of 5-minutes duration starting from 0000 hours and ending with 2400 hours. Accordingly, all the future resource planning, software and hardware development may be undertaken to cater the requirement of scheduling at 15 minutes as well as 5-minute duration.

9.3.2 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.

9.3.3 The State Load Despatch Centre shall be responsible for optimum scheduling and despatch of electricity, monitoring of real time grid operations through secure and economic operation of the State grid and management of the reserves including energy storage systems and demand response within its State control area, supervision and control over the intra-

State transmission system, processing of interface energy meter data and coordinating the accounting and the settlement of State pool account, as may be specified by the Commission.

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

9.3.5 The Users connected to both inter-State transmission system and intra-State transmission system shall be under the control area jurisdiction of RLDC, if more than or equal to 50% of the quantum of connectivity is with ISTS, and if more than 50% of the quantum of connectivity is with intra-State transmission system, it shall be under the control area jurisdiction of SLDC.

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

9.3.7 Unless otherwise decided by the Commission, the Users that have already declared COD as on the date of coming into force of this Grid Code, shall continue to remain under the control area of the SLDC or the RLDC, as the case may be, as existing before the date of coming into force of this Grid Code.

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

9.3.9 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.

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

9.3.11 The SSGS, IPPs and any other thermal generating station shall be required to demonstrate the declared capability of its generating station as and when asked by the SLDC. In the event of the SSGS and IPPs failing to demonstrate the declared capability, the capacity charges due to the generator shall be reduced as a measure of penalty.

9.3.12 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.

9.3.13 DISCOMs or M. P. Power Management Company Limited on behalf of DISCOMs (on receipt of requisition from DISCOMs) will give their requisitions on day ahead and real time basis as per individual Merit Order, i.e., in ascending order of the cost of energy (i.e., variable cost) of generating stations excluding hydro, nuclear and REGS.

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

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

9.3.16 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 Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and amendments thereof.

9.3.17 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:

(a) Coal or lignite fired plants shall declare a ramp up or ramp down rate of not less than 1% of ex-bus capacity corresponding to MCR on bar per minute;

(b) Gas power plants shall declare a ramp up or ramp down rate of not less than 3% of ex-bus capacity corresponding to MCR on bar per minute;

(c) Hydro power plants shall declare a ramp up or ramp down rate of not less than 10% of ex-bus capacity corresponding to MCR on bar per minute;

(d) Renewable Energy generating stations shall declare a ramp up or ramp down rate as

per CEA Regulations.

9.3.18 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.

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

9.4 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 WRPC 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 concerned RLDC and revising the same from time to time based on grid conditions. Assessment of TTC and ATC shall be done on a continuous basis at least Eleven (11) months (M-12) in advance with addition of new elements (commissioned or to be commissioned). SLDC shall submit morning peak, evening peak, day and night

off-peak node-wise load data (MW and MVAR) for 132 kV and above for the preparation of scenarios for computation of TTC and ATC by WRLDC and NLDC. STU in co-ordination with MPPMCL/Distribution Licensees 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.

9.5 Scheduling Process

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

(i) Generating Station based on coal and lignite:

(a) Time block-wise On-bar Declared Capacity (MW) for on-bar units.

(b) Time block-wise Off-bar Declared Capacity (MW) for off-bar units.

(c) Time block-wise Ramp up rate (MW/ min) for on-bar capacity.

(d) Time block-wise Ramp down rate (MW/min) for on -bar capacity.

(e) MWh capability for the day.

(f) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar.

(ii) Generating Station based on hydro energy:

(a) Time block-wise ex-bus declared capacity.

(b) MWh capability for the day.

(c) Ex-bus peaking capability in MW and MWh.

(d) Time block-wise Ramp up rate (MW/min) for on-bar capacity.

(e) Time block-wise Ramp down rate (MW/min) for on-bar capacity.

(f) Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity.

(g) Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.

(h) Unit-wise maximum MW along with probable combination of unit maximum in case adequate water is not available.

(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 breakup of aggregate available capacity of the pooled generation shall also be furnished.

(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 breakup of aggregate available capacity of the pooled generation shall also be furnished.

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

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

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

9.5.4 SLDC will compile the generator-wise availability for ISGS/ other agreements /SSGS/ IPPs/ REGS entitlement of each Beneficiary or Buyer for 'D' day at 15-minute interval and shall intimate the same to MPPMCL/ Distribution Licensees, Railways and other Distribution Licensees including Deemed Licensees (Special Economic Zones) by 07:15 AM on 'D-1' day.

9.5.5 By 07:30 AM of 'D-1' day, MPPMCL/ Distribution Licensees, Railways and Other Distribution Licensees including Deemed Licensees (Special Economic Zones) will furnish requisition to SLDC in each ISGS, other agreements, Intra-State, SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of 'D' day.

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

9.5.7 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.

9.5.8 WRLDC 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.

9.5.9 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.

9.5.10 WRLDC shall issue final drawal schedules and injection schedules for the State by 9 AM on 'D-1' day. WRLDC shall convey the generating station-wise drawal schedule of the State by 9:00 AM on 'D-1' day.

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

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

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

9.5.14 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.

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

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

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

9.5.18 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.

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

- Ex-power plant generation schedule of SSGS/IPPs and other State generators including wind/ solar generators, Hybrid of wind and solar Generating Stations and Energy Storage System (ESS).
- Drawal schedule of State Distribution Licensees including Deemed Licensees (Special Economic Zones) and Railways.

9.6 Rules for revision in schedule

(i) In the event of a situation arising due to bottleneck in evacuation of power due to transmission constraint, SLDC shall revise the schedule, which shall become effective from 4th time block, counting the time block in which the transmission constraint has been brought to the notice of SLDC as the first one. During the first three time blocks also, the schedule shall be deemed to have been revised to be equal to the actual generation by SSGS and actual drawal by the DISCOMs.

(ii) In case of any grid disturbance, the scheduled generation of all the generating stations and scheduled drawal shall be deemed to have been revised 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 SLDC/RLDC 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 better system operation, it may do so on its own and in such cases, the revised schedule shall become effective from 4th time block, counting the

time block in which the revised schedule is issued by SLDC to be the first one.

(iii) 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 and 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 pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from 4th time block, counting the time block in which revision is advised by the generators to be the first one:

Provided that the generating station or ESS (as injecting entity) or Trading Licensee or any other agency selling power from a generating station or unit(s) thereof or ESS, may revise its estimated restoration time once in a day and the revised schedule shall become effective from 4th time block, counting the time block in which the revision is informed by the generator or ESS to be the first one:

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

(iv) 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 4th time block, counting the time block in which the revision is informed by WS seller to be the first one.

(v) 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 4th time block, counting the time block in which the revision is informed to SLDC to be the first one.

(vi) 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 RLDC and SLDC.

(vii) SLDC, on behalf of intra-State drawee entities may revise their schedules, which shall become effective from 4th 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.

(viii) 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 WRLDC implemented schedule. Further, the implemented schedule may be revised by SDLC, if Ex-post facto revision in implemented schedule is made by WRPC. 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.

9.7 Scheduling from alternate source of power by a generating station

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

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

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

(b) In case of bilateral transaction, the generating station shall request SLDC to schedule power from such alternate supplier to its beneficiaries, which shall become effective from 4th time block.

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

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

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

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

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

(b) The generating station shall request SLDC to schedule power from such alternate source to its beneficiaries, which shall become effective from 4th time block.

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

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

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

9.7.5 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.

9.8 Minimum Turndown Level for operation of Thermal Generating Stations

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

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

Provided further that such generating station on its own option may declare a minimum turndown level below the minimum turndown level specified in this Regulation:

Provided also that the thermal generating stations whose tariffs are 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 to be specified by the Commission separately.

9.8.2 The SSGS having 100% installed capacity tied up/contracted with MPPMCL/ DISCOMs 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 on the below mentioned parameters on monthly basis duly supported by relevant data verified by SLDC:

(i) In case of thermal generating stations, following station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation:

Sr. No.	Unit loading as a % of Installed Capacity of Unit	Increase in SHR (for supercritical Units)	Increase in SHR (for sub-critical Units)
	(%)	(%)	(%)
1	85-100	Nil	Nil
2	75-84.99	1.25	2.25
3	65-74.99	2.00	4.00
4	55-64.99	3.00	6.00

(ii) In case of thermal generating stations, following Auxiliary Energy Consumption degradation or actual, whichever is lower, shall be considered for the purpose of compensation:

Sl. No.	Unit Loading (% of MCR)	% Degradation in AEC admissible
1.	85- 100	NIL
2.	75 – 84.99	0.35
3.	65 – 74.99	0.65
4.	55 – 64.99	1.00

(iii) In case the scheduled generation thermal 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 following norms or actual, whichever is lower.

Unit Size (MW)	Oil consumption per start up (kL)		
	Hot	Warm	Cold
Up to 300	20	30	50
500/ 600	30	50	90
660 and above	40	60	110

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

(v) 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 WRPC.

(vi) 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.

(vii) 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.

9.8.3 In case of generating stations other than SSGS, wherein the 100% installed capacity is not tied up with MPPMCL/ DISCOMs 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 MPPMCL/ DISCOMs for sale of power, in order to claim compensation for operating at the technical minimum schedule.

9.8.4 The Commission, in its Order dated 29.01.2020, had approved the Detailed Operating Procedure (DOP) for backing down of coal based thermal units of SSGSs and IPPs and mechanism for compensation for degradation of heat rate, auxiliary consumption and secondary fuel oil consumption, due to Part Load Operation and Multiple Start/Stop of Units under Reserve Shut-down. Subsequently, the Commission in its Order dated 12.10.2022 in Case No. 33 of 2022, had amended the above-said Detailed Operating Procedure. Any modification/ changes in the Detailed Operating Procedure in the future, will be approved by the Commission vide separate Order.

9.9 Data Registration

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

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CHAPTER 10

FREQUENCY AND VOLTAGE MANAGEMENT CODE

10. Frequency and Voltage Management Code

10.1 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 Western Region Grid and WRLDC has the overall responsibility of the integrated operation of the Western Regional Power System. The constituents of the Region are required to follow the instructions of WRLDC 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.

10.2 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/ MPEGC.

10.3 Frequency Management

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

10.3.2 **Falling frequency**

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

10.3.3 **Rising Frequency**

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

10.4 Reserve

10.4.1 There shall be reserves as under:

(a) Primary, Secondary and Tertiary reserves:

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

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

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

(iv) 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.

(b) Black Start reserves:

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

(c) Voltage Control reserves:

Voltage Control reserves shall be deployed for controlling the voltage at a bus or sub-system through reactive power injection or drawal.

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

10.4.3 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.

10.4.4 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.

10.5 Control Hierarchy

10.5.1 **Inertia**

The power system shall be operated at all times with a minimum inertia to be stipulated by NLDC so that the minimum nadir frequency post reference contingency stays above the

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

10.5.2 **Primary Control**

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

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

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

(d) The generating stations and units thereof shall have electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity Regulations and are mandated to provide PRAS. The generating stations and units thereof with governors shall be under Free Governor Mode of Operation.

(e) 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.

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

(g) All the generating units shall have their governors or frequency controllers in operation all the time with droop settings of 3 to 6 % (for thermal generating units and WS Seller) or 0-10% (for hydro generating units) as specified in the CEA Technical Standards for Connectivity Regulations. The primary response requirement of various types of generating units shall be as mentioned below:

Fuel/ Source	**Minimum unit size/ Capacity**	**Up to**
Coal/Lignite Based	200 MW and above	±5% of MCR
Hydro	25 MW and above	±10% of MCR
Gas based	Gas Turbine above 50 MW	±5% of MCR (corrected for ambience temperature)
WS Seller	Capacity of Generating 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.

(h) All generating stations mentioned in above table shall have the capability of instantaneously picking up to a minimum of 105% of their operating level and up to 105% or 110% of their MCR, as the case may be, when the frequency falls suddenly and thus providing primary response whenever conditions arise.

(i) 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.

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

(k) The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control or coordinated

control system, and no time delays shall be deliberately introduced. In the case of a renewable energy generating unit, a reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency response within its capabilities. The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz. 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.

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

(m)The Primary Reserves Ancillary Service (PRAS) shall start immediately when the frequency deviates beyond the dead band as specified in above Regulation **10.5.2(k)** and shall be capable of providing its full PRAS capacity obligation within 45 seconds and sustaining at least for the next five (5) minutes.

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

(o) The concerned RLDC 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.

(p) 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.

(q) 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.

10.5.3 Secondary Control and Tertiary Control shall be such as may be notified by the Commission separately.

10.6 Voltage Management

10.6.1 Users using the State Transmission System shall make all possible efforts to ensure that the grid voltage always remains within the limits specified in IEGC and amended thereof. The

specified limit of voltage specified in IEGC are reproduced below:

Voltage (kV rms)		
Nominal	**Maximum**	**Minimum**
765	800	728
400	420	380
230*	245*	207*
220	245	198
132	145	122
110	121	99
33	36	30

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

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

10.6.3 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 DISCOMs at 33 kV sub-stations, operation of Hydro unit as synchronous condenser and use of MVAr reserves with the generators within its control area within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

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

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

10.7 Reactive Power management

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

10.7.2 All generating stations shall be capable of supplying reactive power support so as to maintain power factor at the point of inter-connection within the limits of 0.95 lagging to 0.95 leading as per the CEA Technical Standards for Connectivity Regulations and amendments thereof.

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

10.7.4 The reactive interchange of Users shall be measured and monitored by SLDC/ RLDC.

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

10.7.6 SLDC shall assess the dynamic reactive power reserve available at various sub-stations or generating stations under any credible contingency on a regular basis based on technical details and data provided by Users, as per the procedure specified by NLDC/ SLDC.

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

(i) Shunt reactors,

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

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

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

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

(vi) Synchronous condenser,

(vii) Static VAR compensators (SVC), STATCOM and other FACTS devices,

(viii) Transformer tap change: generator transformer and inter-connecting transformer,

(ix) HVDC power order or HVDC controller selection to optimise filter bank.

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

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

10.7.10 Hydro and gas generating units having this capability shall operate in synchronous

condenser mode operation as per instructions of the respective RLDC or SLDC. Standalone synchronous condenser units shall operate as per the instructions of respective RLDC or SLDC.

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

10.7.12 If voltage is outside the limit as specified in **Regulation 10.6.1** of the Grid Code and the means of voltage control set out in **Regulation 10.7.7** of the Grid Code are exhausted, SLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including switching ON or OFF of lines considering the security of the system.

10.7.13 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.

10.7.14 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.

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

10.8 General

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

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CHAPTER 11

MONITORING OF GENERATION AND DRAWAL CODE

11. Monitoring of Generation and Drawal Code

11.1 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 DISCOMs contribute towards improving system performance and observe grid discipline.

11.2 Objective

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

11.3 Monitoring Procedure

11.3.1 SLDC shall continuously monitor generating unit outputs and bus voltages for effective operation of the State Transmission System and ensure that declared availability of generating stations are realistic.

11.3.2 SLDC can instruct a generating station to demonstrate its declared availability, in case SLDC has a reason to believe that declared availability of generating station does not match with actual availability or declared output does not match the actual output.

11.3.3 SLDC shall inform the generating stations, in writing, if continued monitoring demonstrates an apparent persistent or material mismatch between the despatch instructions and the generating unit output or breach of the Connection Conditions. Continued discrepancies shall be resolved in Grid Code Review Committee meeting with a view to either improve performance in future, providing more realistic declarations or initiate appropriate actions for any breach of Connectivity Conditions.

11.3.4 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.

11.4 Generating Unit Trippings

11.4.1 Generating stations shall immediately inform the tripping of a generating unit, with reasons, to SLDC in accordance with the operational event/ accident reporting Regulation. SLDC shall keep a written log of all such trippings, along with reasons, with a view demonstrating

the effect on system performance and identifying the need for remedial measures.

11.4.2 The operating log books/ log records of the generating station and EHV sub-stations shall be available for review by SLDC. These books/ records shall keep record of machine operation, outage/ tripping of transmission elements and maintenance.

11.5 Monitoring of Drawal

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

11.5.2 SLDC shall also monitor the actual MVAr drawal to the extent possible. This will be used to assist in voltage management of the State Transmission System.

11.6 Data Requirement

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

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the effect on system performance and identifying the need for remedial measures.

11.4.2 The operating log books/ log records of the generating station and EHV sub-stations shall be available for review by SLDC. These books/ records shall keep record of machine operation, outage/ tripping of transmission elements and maintenance.

11.5 Monitoring of Drawal

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

11.5.2 SLDC shall also monitor the actual MVAr drawal to the extent possible. This will be used to assist in voltage management of the State Transmission System.

11.6 Data Requirement

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

CHAPTER 12

OUTAGE PLANNING CODE

12. Outage Planning Code

12.1 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.

12.2 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.

12.3 Annual Outage Planning and Process

12.3.1 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 WRPC. SLDC is authorised to defer the planned outage in case of any of the following events:

(a) Major grid disturbance;

(b) System Isolation;

(c) Black out in the State;

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

12.3.2 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.

12.3.3 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.

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

12.3.5 Scheduled outage of 400 kV transmission elements and 220 kV/132 kV inter-State lines shall be effected only with the approval of WRPC in coordination with SLDC.

12.3.6 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.

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

12.3.8 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.

12.4 Schedule for availing of shutdowns

12.4.1 SLDC would review on daily basis the outage schedule for the next two days and in case of any contingency, defer any planned outage as deemed fit, clearly stating the reasons thereof. The revised dates in such cases would be finalized in consultation with User.

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

12.5 Demand and Load Management

12.5.1 The demand and load shall be managed for ensuring grid security.

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

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

(a) 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.

(b) 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.

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

12.6 Post-Despatch Analysis

12.6.1 Operational analysis

(a) SLDC shall analyse the following:

(i) Pattern of demand met, under drawals and over drawals, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, load and RE forecast errors, ancillary services despatched, transmission congestion and (n-1) violations;

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

(iii) Irregular pattern in any of the system parameters mentioned in **Regulation 12.6.1. (a)(i)** and **Regulation 12.6.1(a)(ii)** of the Grid Code and reasons thereof; and

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

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

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

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

(e) For the purpose of analysis and reporting, telemetered data shall be archived with a granularity of not more than five (5) minutes and higher granularity for special events.

Such data shall be stored by SLDC for at least fifteen (15) years and reports shall be stored for twenty-five (25) years for operational analysis.

12.6.2 Event reporting

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

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

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

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

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

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

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

Sr. No.	Grid Event^ (Classification)	Flash report submission deadline (Users/ SLDC)	Disturbance record and station event log submission deadline (Users/ SLDC)	Detailed report and data submission deadline (Users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
1	GI-1/GI-2	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

(g) 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.

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

(i) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during any event in the grid shall be reported to SLDC, if connected to an intra-State system. The transient fault records and event logger data shall be submitted to the SLDC within twenty-four (24) hours of the occurrence of the incident. Generating stations shall submit one (1) second resolution active power and reactive power data recorded during oscillations to SLDC within twenty-four (24) hours of the occurrence of the oscillations.

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

CHAPTER 13

CONTINGENCY PLANNING CODE

13. Contingency Planning Code

13.1 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.

13.2 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.

13.3 Contingency Planning Procedure

13.3.1 SLDC shall prepare contingency plan to efficiently handle the following two types of contingencies:

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

(b) Total black out in the State/region.

13.3.2 In case of partial black out in the system/State, priority should be given for early restoration of power station units, which are tripped. Start-up power for the power station shall be extended through shortest possible line and within shortest possible time from adjoining sub-station/ power station where the supply is available. Synchronising facility at all power stations and 400/ 220 kV sub-station shall be available.

13.3.3 In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of WRLDC 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 WRPC. 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.

13.4 Restoration Procedure

13.4.1 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 Western Region specified under IEGC. SLDC shall review and update the restoration procedure every year.

13.4.2 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.

13.4.3 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 / WRLDC. 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, WRLDC on a quarterly basis.

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

(a) Black start capability of the generator;

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

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

(d) Line/ transformer charging;

(e) Reduced fault levels; and

(f) Protection settings under restoration condition.

13.4.5 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.

13.4.6 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.

13.4.7 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.

13.4.8 Any entity extending black start support by way of injection of power as identified in **Regulation 13.4.6** of the Grid Code shall be paid for actual injection @ 110 % of the normal rate of charges for deviation in accordance with Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 or Madhya Pradesh Electricity Balancing and Settlement Code, 2023, as applicable for the last block in which the grid was available. The procedure in this regard shall be prepared by SLDC in consultation with stakeholders and approved by the Commission.

13.5 Real Time Operation

13.5.1 **System state**

Power system shall be categorized under normal, alert, emergency, extreme emergency and restoration state depending on the type of contingencies and value of operational parameters of the power system by RLDC, NLDC or SLDC, as the case may be.

(a) Normal state

Power system shall be categorized under normal state when the power system is operating with operational parameters within their respective operational limits and equipment are within their respective loading limits. Under normal state, the power system is secure and capable of maintaining stability under contingencies defined in the CEA Transmission Planning Criteria and updated thereof.

(b) Alert state

Power system shall be categorized under alert sate when the power system is operating with operational parameters within their respective operational limits, but a single contingency ('N-1') leads to a violation of security criteria. The power system remains intact under such alert state. However, whenever the power system is under alert state, the system operator shall take corrective measures to bring it back to a normal state.

(c) Emergency state

Power system shall be categorized under emergency state when the power system is

operating with operational parameters outside their respective operational limits or equipment are above their respective loading limits. Emergency state can arise out of multiple contingencies or any major grid disturbance in the system. The power system remains intact under such emergency state. However, whenever the power system is under emergency sate, it is the responsibility of the system operator to bring back the power system to alert/normal and shall take corrective measures such as:

- extreme measures such as load shedding, generation unit tripping, line tripping or closing,
- emergency control action such as HVDC Control, Excitation Control, HP-LP Bypass, tie line flow rescheduling on critical lines, and
- automated action such as system protection scheme, load curtailment scheme and generation run-back scheme.

(d) Extreme emergency state

Power system shall be categorized under extreme emergency state if the control actions taken during the emergency state are not able to bring the system either to an alert state or a normal state and operational parameters are outside their respective operational limits or equipment are critically loaded. Extreme emergency state may arise due to high impact low frequency events like natural disasters. The power system may or may not remain intact (splitting may occur) and extreme events like generation plant tripping, bulk load shedding, under frequency load shedding (UFLS) and under voltage load shedding (UVLS) operation may occur.

(e) Restorative state

Power system shall be categorized under restorative state when control action is being taken to reconnect the system elements and restore system load. The power system transits from a restorative state to either an alert state or a normal state, depending on the system conditions.

13.5.2 SLDC shall maintain the grid in the normal state by taking suitable measures. In case, the power system moves away from the normal state, appropriate measures shall be taken to bring the system back to the normal state. In case the power system has moved to an extreme emergency state, SLDC shall take emergency action and initiate restorative measures immediately.

13.5.3 **Procedure to be followed during an event:**

(a) In case of an event on the intra-State transmission system that may significantly impact

the inter-State transmission system, SLDC shall immediately inform the concerned RLDC;

(b) any warning in respect of system security issued by NLDC/ RLDC/ SLDC, shall be taken note of immediately by the concerned Users who shall take the necessary action to withstand the said event or to minimize its effect.

13.5.4 **Operational coordination:**

(a) For operational coordination, each intra-State Transmission Licensee, generating station and QCA shall have a control centre or coordination centre for round the clock coordination.

(b) Any planned operation activity in the Intra-State Transmission system [such as generating unit synchronization or de-synchronization, transmission element opening or closing (including breakers), protection system outage, System Protection Schemes (SPS) outage and testing, etc.] shall be done by taking operational code from SLDC. The operational code shall have validity period of sixty (60) minutes from the time of issue. In case such operation activity does not take place within the validity period of the code, the entity shall obtain a fresh operational code from SLDC.

13.6 Special Considerations

13.6.1 During the restoration process, normal standards of voltage and frequency shall not apply.

13.6.2 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.

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

13.6.4 Despite the urgency of the situation, careful prompt and complete logging of all operations and operational messages shall be ensured by all Users to facilitate subsequent investigation into the incident and the efficiency of the restoration process. Such investigation shall be conducted promptly after the incident.

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

CHAPTER 14

INTER-USER BOUNDARY SAFETY CODE

14. Inter-User Boundary Safety Code

14.1 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.

14.2 Objective

The objective of this chapter is to achieve agreement and consistency on the principles of safety as specified in the Indian Electricity Rules when working across an inter-user boundary between one User and another User.

14.3 Designated Officers

STU and all Users shall nominate authorized persons responsible for the co-ordination of safety across the Company boundary. These persons shall be referred as Designated Officer.

14.4 Procedure

14.4.1 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.

14.4.2 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.

14.4.3 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.

14.4.4 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.

14.4.5 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.

14.4.6 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.

14.4.7 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.

14.4.8 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.

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

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

14.5 Special Consideration

14.5.1 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.

14.5.2 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.

14.5.3 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.

CHAPTER 15
REPORTS

15. Reports

15.1 Periodic reports

15.1.1 **Monthly Report**

A monthly report shall be uploaded by SLDC on its website, which shall cover the performance of the State grid for the previous month. The monthly report shall contain the following:

(a) Frequency profile.

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

(c) Voltage profile.

(d) Voltage profile of selected sub-stations.

(e) Major Generation and Transmission Outages.

(f) Transmission Constraints.

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

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

15.1.2 **Other Reports/ Forms**

The SLDC shall also upload a quarterly report on its website, which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of various actions taken by different Users and the Users responsible for causing the constraints.

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

15.2 OPERATIONAL EVENT/ ACCIDENT REPORTING

15.2.1 **Introduction**

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

15.2.2 **Objective**

The objective of this chapter is to define the incidents to be reported, the reporting route to be followed and the information to be supplied to ensure a consistent approach for reporting of incidents and accidents on the Intra-State Transmission System.

15.2.3 **Reportable Incidents**

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

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

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

(c) Loss of Generating Unit.

(d) Instance of Black Start.

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

(f) Major fire incidents.

(g) Major failure of protection.

(h) Equipment and transmission line overload.

(i) Accidents - Fatal and Non-Fatal.

(j) Load Crash / Loss of Load.

(k) Violation of Security Standards.

(l) Grid indiscipline.

(m)Non-compliance of SLDC instructions.

(n) Excessive drawal deviations.

(o) Minor equipment alarms.

The last two reportable incidents are typical examples of those, which are of lesser consequence, but still affect the State Transmission System and can be reasonably classed as minor. They will require corrective action but may not warrant management reporting until these are repeated for sufficient time.

15.2.4 **Reporting Procedure/ Forms**

(a) All reportable incidents occurring in lines and equipment of 132 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.

(b) Within one (1) hour of being informed by the Reporting User, SLDC may ask for a written report on any incident as per **Appendix-H.**

(c) If case of minor incident, the Reporting User shall submit an initial written report within two (2) hours and comprehensive report within twenty-four (24) hours of the submission of the initial written report, whereas, in other cases, the Reporting User shall submit a report within five (5) working days to SLDC.

(d) SLDC may call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been source of the reportable incident. This shall not relieve any User from the obligation to report events in accordance with IE Rules.

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

i) Location of incident.

ii) Date and time of incident.

iii) Plant or equipment involved.

iv) Details of relay indications with nature of fault implications.

v) Supplies interrupted and duration if applicable.

vi) Amount of generation lost if applicable.

vii) Brief description of incident.

viii) Estimate of time to return to service.

ix) Name of originator.

x) Possibility of alternate arrangement of supply

xi) Single line diagram

xii) All Relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, Data Acquisition System (DAS), etc.

15.2.5 **Major Failure**

Following a major failure, SLDC and other Users shall co-operate to inquire and establish the cause of such failure and produce appropriate recommendations. The SLDC shall report the major failure to the Commission immediately for information and shall submit the enquiry report to the Commission within two (2) months of the incident.

15.2.6 **Accident Reporting**

Reporting of accidents shall be in accordance with the relevant Rules/ Regulations/ Grid Code. In both fatal and non-fatal accidents, the report shall be sent to the Electrical Inspector in the specified form.

PART IV

CHAPTER 16

PROTECTION CODE

16. Protection Code

16.1 Introduction

16.1.1 The chapter covers the protection protocol, protection settings and protection audit plan of electrical systems to be adopted in order to safeguard the State Transmission System and User's system from faults.

16.2 Objective

16.2.1 The objective of this chapter is to define the minimum protection requirements for any equipment connected to the State Transmission System and thereby minimize the disruption due to faults.

16.3 General Principles

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

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

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

(c) specifying timelines for submission of data;

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

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

16.3.2 STU shall be guided by the advice of WRPC / WRLDC 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.

16.3.3 Under-Frequency relay for load shedding, relays provided for islanding scheme, disturbance recorder, and fault locator installed at various sub-stations shall be tested and calibrated. All Users shall ensure correct and appropriate settings of protection equipments.

16.3.4 Protection settings shall not be altered or protection bypassed and/or disconnected without consultation and agreement of all affected Users. In the case where protection is bypassed and/or disconnected, by agreement, then the cause must be rectified, and the protection

restored to normal condition as quickly as possible. If agreement has not been reached, the electrical equipment will be removed from service forthwith.

16.3.5 No item of electrical equipment shall be allowed to remain connected to the State Transmission System unless it is covered by minimum specified protection aimed at reliability, selectivity, speed and sensitivity.

16.4 Protection Co-ordination

A Protection Coordination Committee (PCC) shall be constituted as per **Chapter 3** of the 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 mal-function or issue as discussed and agreed to, in the periodical meetings.

16.5 PROTECTION PROTOCOL

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

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

16.5.3 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.

16.5.4 The protection protocol in a particular system may vary depending upon operational experience. Changes in protection protocol, as and when required, shall be carried out after deliberation and approval of the Protection Coordination Committee (PCC).

16.5.5 Violation of the protection protocol of the State shall be brought to the notice of Protection

Coordination Committee (PCC) by SLDC.

16.6 PROTECTION SETTINGS

16.6.1 Protection Coordination Committee (PCC) shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders of the State from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the 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).

16.6.2 All Users connected to the grid shall:

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

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

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

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

(e) ensure proper coordinated protection settings.

16.6.3 Protection Coordination Committee (PCC) shall:

(a) 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 132 kV and above. SLDC shall also maintain such database.

(b) carry out detailed system studies once in a year, for protection settings and advice modifications / changes, if any, to STU and all Users. The data required to carry out such studies shall be provided by SLDC, STU and Users, as the case may be.

(c) provide the database access to STU and SLDC and to all Users of the State. The database shall have different access rights for different Users.

16.6.4 The changes in the network and protection settings of grid elements connected to 132 kV and above shall be informed to Protection Coordination Committee (PCC) by SLDC and STU, as the case may be.

16.7 PROTECTION AUDIT PLAN

16.7.1 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.

16.7.2 All Users except those under **Regulation 16.7.1** of the Grid Code and having sub-stations at voltage level 220 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.

16.7.3 All Users except those under **Regulation 16.7.1** of the Grid Code and having sub-stations at voltage level 132 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.

16.7.4 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.

16.7.5 The third-party protection audit report shall contain information sought in the format enclosed as **Appendix–J.** The protection audit reports along with action plan for rectification of deficiencies detected, if any, shall be submitted to 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.

16.7.6 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.

16.7.7 Users shall submit the following protection performance indices of previous month to Protection Coordination Committee (PCC) and SLDC on monthly basis for 132 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;

N_u is the number of unwanted operations; and

N_i is the number of incorrect operations and is the sum of N_f and N_u.

16.7.8 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).

16.7.9 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.

16.8 SYSTEM PROTECTION SCHEME (SPS)

16.8.1 System Protection Scheme (SPS) for identified system shall have redundancies in measurement of input signals and communication paths involved up to the last mile to ensure security and dependability.

16.8.2 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).

16.8.3 The Users and SLDC shall report about the operation of System Protection Scheme (SPS) immediately and detailed report shall be submitted within three days of operation to Protection Coordination Committee (PCC) in the format specified by Protection Coordination Committee (PCC).

16.8.4 The performance of System Protection Scheme (SPS) shall be assessed as per the protection performance indices specified in this Grid Code. In case, the System Protection Scheme (SPS) fails to operate, the concerned User shall take corrective actions and submit a detailed

report on the corrective actions taken to Protection Coordination Committee (PCC) within a fortnight.

16.9 RECORDING INSTRUMENTS

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

16.9.2 The disturbance recorders shall have time synchronization and a standard format for recording analog and digital signals, which shall be included in the guidelines issued by Protection Coordination Committee (PCC).

16.9.3 The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers by SLDC. Disturbance recorders, which are non-compliant shall be listed out for discussion at Protection Coordination Committee (PCC) meeting.

16.10 Calibration and Testing

16.10.1 The protection scheme shall be tested at each 400 kV and 220 kV sub-station by STU once in a year or immediately after any major fault, whichever is earlier. However, in case of 132 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.

16.10.2 All equipment owners shall submit a testing plan for the next year to the STU/SLDC/WRPC by 31st October to ensure proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform the concerned STU/SLDC/WRPC in advance.

16.10.3 The tests shall be performed once every five (5) years or whenever major retrofitting is done. If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so, advised by SLDC or RLDC or NLDC or WRPC, as the case may be.

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

16.10.5 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.

16.10.6 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 100 MW and above for Coal/lignite, 50 MW and above gas turbine and 25 MW and above for Hydro.
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (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

16.11 CAPACITY BUILDING AND CERTIFICATION

Capacity building, skill upgradation, and certification of the personnel deployed in Generating Stations, Load Despatch Centres and EHV Sub-stations shall be done periodically under an institutional framework through accredited certifying agency(ies).

16.12 Data Requirements

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

PART V

CHAPTER 17

TRANSMISSION METERING CODE

17. Transmission Metering Code

17.1 Introduction

The Transmission Metering Code prescribes a uniform policy in respect of electricity metering for State Transmission Utility (STU), 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 Madhya Pradesh.

17.2 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 will also provide information, which will help to optimize the system planning.

17.3 Scope

17.3.1 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.

17.3.2 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.

17.4 Reference Standards/ Regulations

17.4.1 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 a 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 for nominal system frequency, nominal system voltage, ambient temperature, humidity, and other conditions prevailing in India before actual

adoption of the said Standard.

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

17.5 Ownership

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

17.6 Other Technical Requirements for Metering

17.6.1 **Data Display Capabilities - Instantaneous Values:**

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

(a) Three rms line voltages/ currents

(b) System frequency (Hz)

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

(d) Watt - Import/ Export

(e) VAr - Lead/ Lag

(f) VA - Import/ Export

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

(h) Meter Serial Number

17.6.2 **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:

(a) Watt hour - Import/ Export

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

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

(d) VA hour – Import/ Export

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

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

17.6.3 **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 17.6.1** and **Regulation 17.6.2** 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. At least, following essential parameters shall be logged at an interval of 15 minutes:

(a) Watt - Import/ Export

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

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

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

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

(f) Average frequency (Hz)

(g) Average three phase voltage.

17.6.4 **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. User shall be able to program time and day at which value of energy to be stored in the memory.

17.6.5 **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:

(a) Missing potential (VT supply missing)

(b) CT/VT Polarity reversal

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

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

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

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

(g) Meter internal set-up/program change information

Note:

[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.*

17.6.6 **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.

17.6.7 **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.

17.6.8 **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.

17.6.9 **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.

17.6.10 **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.

17.6.11 **Display**

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.

17.6.12 **Data Security**

The metering system should have the following facilities:

(a) Data encryption (coding) capability,

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

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

(d) Independent security across communication channels.

17.6.13 **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.

17.6.14 **Communication Ports**

The meter shall have at least the following communication ports:

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

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

17.6.15 **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.

17.6.16 **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).

17.6.17 **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.

17.6.18 **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.

17.6.19 **External Auxiliary Supply**

(a) The meters shall be capable of powered up with 240 V AC auxiliary supply and 110 V or 220 V 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.

(b) 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.

17.6.20 The Interface meters shall be of open protocol confirming 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:

(a) 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)

(b) Net Wh transmitted during each successive 15-minutes block, up to second decimal, with plus/minus sign.

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

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

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

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

(g) 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 0.01 Hz and they must be capable of recording Voltage and Reactive Energy at every 5-minutes and have feature of auto-time synchronization through GPS.

(h) 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.

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

(j) 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.

17.7 Minimum Technical Requirement for Current Transformer (CT)

17.7.1 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.

17.7.2 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.

17.7.3 The total burden connected to each current transformer shall not exceed the rated burden of CT. Total circuit burden shall be kept close to rated burden of CT for minimum error.

17.8 Minimum Technical Requirement for Voltage Transformers (VT)

17.8.1 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 $110/\sqrt{3}$ volts or $415/\sqrt{3}$ 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.

17.8.2 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.

17.8.3 The 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.

17.9 Location and Application of Metering System

17.9.1 **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.

17.9.2 **Metering between State Transmission Utility –Distribution Licensee**

(a) 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 132/33kV, and 11 kV side of 132/11kV transformers installed in EHV sub-stations. The standby metering shall be provided on the HV side of EHV Power Transformer, i.e., 220/33 kV, 132/33kV and 132/11kV transformers installed in EHV sub-stations.

Operational meters shall also be provided on all outgoing 33 kV and 11 kV feeders for energy audit on feeder and reconciliation of energy with respect to energy measured on LV side of EHV Power Transformer.

(b) 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.

17.9.3 **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.

17.9.4 **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.

17.9.5 **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.

17.9.6 In addition to provisions of **Regulations 17.9.1 to 17.9.5**, the location and application of metering system shall be as per CEA Metering Regulations as amended.

17.10 Data Collection Systems and Data Downloading

17.10.1 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.

17.11 Testing Arrangements

17.11.1 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.

17.11.2 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.

17.12 System for Joint Inspection, Testing, Calibration

17.12.1 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 dispatch 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 17.16** 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.

17.12.2 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.

17.13 Meter Sealing Provision

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

17.13.2 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.

17.13.3 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.

17.13.4 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.

17.14 Access to Equipment and Data

17.14.1 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.

17.15 Operation and Maintenance of the Metering System

17.15.1 The maintenance of the meters shall be the exclusive responsibility of the owner of the meters.

17.15.2 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.

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

17.16.1 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.

17.16.2 If main as well as check metering systems become defective, the assessment of energy consumption for the outage period shall be done by the concerned parties as mutually agreed or at the level of Transmission Metering Committee or as per Madhya Pradesh Electricity Balancing and Settlement Code, 2023 and amendments thereof.

17.17 Mechanism for Dispute Resolution

17.17.1 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 given 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.

17.18 Implementation of Transmission Metering Code

17.18.1 For existing metering system not complying with this Code, State Transmission Utility 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.

17.18.2 For any new procurement of metering system, this Code shall be applicable immediately.

17.19 Dynamic Code

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

17.19.2 If any of the provisions of the prevailing Metering Code of Madhya Pradesh Electricity 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 18

CYBER SECURITY CODE

18. Cyber Security Code

18.1 General

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

(ii) All Users, SLDC and STU shall have in place, a Cyber Security framework in accordance with Information Technology Act, 2000, CEA Technical Standards for Connectivity Regulations, CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such Regulations issued from time to time, by an appropriate authority to identify the critical cyber assets and protect them so as to support reliable operation of the grid.

18.2 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.

18.3 Mechanism of Reporting

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

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

18.4 Cyber Security Coordination Forum

(i) 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.

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

PART VI

DATA REGISTRATION CODE & MISCELLANEOUS

CHAPTER 19

DATA REGISTRATION CODE

19. Data Registration Code

19.1 Introduction

This chapter contains list of data required by STU and SLDC, which is to be provided by Users and data required by Users to be provided by STU at times specified in the Grid Code. Other chapters of the Grid Code contain the obligation to submit the data and defines the times, when such data is to be provided by Users.

19.2 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.

19.3 Responsibility

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

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

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

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

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

19.4 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.

19.5 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.

19.6 Methods of submitting Data

(i) The data shall be furnished to SLDC/STU in the standard formats. However, in cases where standard formats are not enclosed, the same would be developed by SLDC/ STU in consultation with Users.

(ii) Where a computer data link exists between a User and SLDC/ STU, data may be submitted via link. Other modes of data transfer, such as pen drive may be utilised, if SLDC/ STU gives its prior written consent.

19.7 Special Considerations

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

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

CHAPTER 20
MISCELLANEOUS

20. Miscellaneous

20.1 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.

20.2 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.

20.3 Repeal and Savings

(a) The Grid Code namely "Madhya Pradesh Electricity Grid Code (Revision-II), 2019 (No. RG-14(ii) of 2019) notified on 21.06.2019 and read with all amendments thereto, as applicable to the subject matter of this Grid Code are hereby superseded.

(b) Nothing in this Grid Code shall be deemed to limit or otherwise affect the inherent powers of the Commission to make such orders as may be necessary for ends of justice to meet or to prevent abuses of the process of the Commission.

(c) Nothing in this Grid Code shall bar the Commission from adopting, in conformity with the provisions of the Act, a procedure which is at variance with any of the provisions of this Grid Code, if the Commission, in view of the special circumstances of a matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

(d) Nothing in this Grid Code shall, expressly or impliedly, bar the Commission dealing with any matter or exercising any power under the Act for which no Regulations have been framed and the Commission may deal with such matters, power and functions in a manner it thinks fit.

20.4 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.

20.5 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.

Note: In case of discrepancy between Hindi 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.

By order of the Commission,
UMAKANTA PANDA, Secy.

APPENDIX

APPENDIX A: STANDARD PLANNING DATA

Standard Planning Data consist of details, which are expected to be normally sufficient for STU to investigate the impact on the State Transmission System due to User development.

Standard planning data covering (a) preliminary project planning

REFERENCE TO:

CHAPTER - 4 RESOURCE ADEQUACY AND SYSTEM PLANNING CODE

CHAPTER - 5 CONNECTION CODE

A-1 STANDARD PLANNING DATA (GENERATION)

For **SSGS** – Thermal

A.1.1 THERMAL (COAL / GAS/FUEL LINKED)

A.1.1.1 GENERAL

i	Site	Give location map to scale showing roads, railway lines, 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 v/s 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 Madhya Pradesh for which Distribution **License** is applied.
ii	Consumer Data	Furnish categories of consumers, their numbers and connected loads.
iii	Furnish categories of consumers, their numbers and connected loads.	

A.3.2 CONNECTION

i	Points of **Connection**	Furnish single line diagram showing points of **Connection**
ii	Voltage of supply at points of **Connection**	
iii	Names of Grid Sub-Stations feeding the points of **Connection**	

A.3.3 LINES AND SUB-STATIONS

i	Line Data	Furnish lengths of line and voltages within the Area.
ii	Sub-station Data	Furnish details of 33/11kV sub-station, 11/0.4kV sub-stations, capacitor installations

A.3.4 LOADS

i	Loads drawn at points of **Connection.**
ii	Details of loads fed at **EHV**, if any. Give name of consumer, voltage of supply, contract demand and name of Grid Sub-station from which line is drawn, length of **EHV** line from Grid Sub-station to consumer's premises.
iii	Reactive Power compensation installed

A.3.5 DEMAND DATA (FOR ALL LOADS 1 MW AND ABOVE)

i	Type of load	State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads etc.
ii	Rated voltage and phase	
iii	Electrical loading of equipment	State number and size of motors, types of drive and control arrangements.
iv	Power Factor	
v	Sensitivity of load to voltage and frequency of supply.	
vi	Maximum Harmonic content of load.	
vii	Average and maximum phase unbalance of load	
viii	Nearest sub-station from which load is to be fed	
ix	Location map to scale	Showing location of load with reference to lines and sub-stations in the vicinity

A.3.6 LOAD FORECAST DATA

Peak load and energy forecast for each category of loads for each of the succeeding 5 years. Details of methodology and assumptions on which forecasts are based.

If supply is received from more than one sub-station, the sub-station wise break up of peak load and energy projections for each category of loads for each of the succeeding 5 years along with estimated Daily load curve.

Details of loads 1 MW and above.

Name of prospective consumer.
Location and nature of load/complex.
Sub-Station from which to be fed.
Voltage of supply.
Phasing of load.

APPENDIX B: DETAILED PLANNING DATA

REFER TO:

CHAPTER – 4 RESORUCE ADEQUACY AND SYSTEM PLANNING CODE

CHAPTER -- 5 CONNECTION CODE

B.1 DETAILED PLANNING DATA (GENERATION)

PART-I FOR ROUTINE SUBMISSION

B.1.1 THERMAL POWER STATIONS

For **SSGS** – Thermal

B.1.1.1		**GENERAL**
	1.	Name of **Power Station.**
	2.	Number and capacity of **Generating Units** (MVA).
	3.	Ratings of all major equipments (Boilers and major accessories, Turbines,
		Generator Unit Transformers etc.).
	4.	Single line Diagram of **Power Station** and switchyard.
	5.	Relaying and metering diagram.
	6.	Neutral Grounding of **Generating Units**.
	7.	Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors)
	8.	Earthing arrangements with earth resistance values.
B.1.1.2		**PROTECTION AND METERING**
	i.	Full description including settings for all relays and protection systems on the
		Generating Unit, Generator unit Transformer, Auxiliary Transformer electrical
		motor of major equipments listed, but not limited to, under Sec. 3 (General).
	ii.	Full description including settings for all relays installed on all outgoing feeders
		Power Station switchyard, Tie circuit breakers, and incoming circuit
	iii.	Full description of inter-tripping of circuit breakers at the point or points of
		with the **Transmission System**.
	iv.	Most probable fault clearance time for electrical faults on the **User's**.
	v.	Full description of operational and commercial metering schemes.
B.1.1.3		**SWITCHYARD**

In relation to interconnecting transformers:

i	Rated MVA.
ii	Voltage Ratio
iii	Vector Group.
iv	Positive sequence reactance for maximum, minimum, normal Tap. (% on MVA).
v	Positive sequence resistance for maximum, minimum, normal Tap. (% on MVA).
vi	Zero sequence reactance (% on MVA).
vii	Tap changer Range (+% to -%) and steps.
viii	Type of Tap changer. (off/on load).

In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of **Connection**:

i	Rated voltage (kV).
ii	Type of circuit breaker (MOCB/ABCB/SF6).
iii	Rated short circuit breaking current (kA) 3 phase.
iv	Rated short circuit breaking current (kA) 1 phase.
v	Rated short circuit making current (kA) 3 phase.
vi	Rated short circuit making current (kA) 1-phase.
vii	Provisions of auto reclosing with details. (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.1.1.5Parameters 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.1.1.6Parameters 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.1.1.7Operational 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.

(a) Basic Insulation Level (kV)

i	Bus bar.
ii	Switchgear.
iii	Transformer Bushings
iv	Transformer windings.

B.1.2.4 GENERATING UNITS

(a) Parameters of Generator

i.	Rated terminal voltage (kV).
ii.	Rated MVA.
iii.	Rated MW.
iv.	Speed (rpm) or number of poles.
v.	Inertia constant H (MW sec./MVA).
vi.	Short circuit ratio.
vii.	Direct axis synchronous reactance Xd (% on MVA).
viii.	Direct axis (saturated) transient reactance (% on MVA) X'd.
ix.	Direct axis (saturated) sub-transient reactance (% on MVA) X"d.
x.	Quadrature axis synchronous reactance (% on MVA) Xq.
xi.	Quadrature axis (saturated) transient reactance (% on MVA) X'q.

xii.	Quadrature axis (saturated) sub-transient reactance (% on MVA) X"q.
xiii.	Direct axis transient open circuit time constant (sec) T'do.
xiv.	Direct axis sub-transient open circuit time constant (sec) T"do.
xv.	Quadrature axis transient open circuit time content (sec) T'qo.
xvi.	Quadrature axis transient open circuit time constant (sec) T"qo.
xvii.	Stator Resistance (Ohm) Ra.
xviii.	Stator leakage reactance (Ohm) X1.
xix.	Stator time constant (Sec).
xx.	Rated Field current (A).
xxi.	Neutral grounding details.
xxii.	Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this.
xxiii.	Type of Turbine.
xxiv.	Operating Head (Metres)
xxv.	Discharge with full gate opening (cumecs)
xxvi.	Speed Rise on total Load throw off (%).
xxvii.	MW and MVAr Capability curve

(b)

Parameters of excitation control system:	As applicable to thermal **Power Stations**

(c)

Parameters of governor:	As applicable to thermal **Power Station**

(d) Operational parameter:

i	Minimum notice required to Synchronise a **Generating Unit** from de-synchronisation.
ii	Minimum time between Synchronising different **Generating Units** in a **Power Station.**
iii	Minimum block load requirements on Synchronising.

B.1.2.5 GENERAL STATUS

i	Detailed Project Report.
ii	Status Report. (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.

B.1.2.6 CONNECTION

i. Reports of Studies for parallel operation with the **State Transmission System.**

(a)	Short Circuit studies
(b)	Stability Studies.
(c)	Load Flow Studies.

ii. Proposed **Connection** with the **State Transmission System.**

(a)	Voltage
(b)	No. of circuits
(c)	Point of **Connection.**

B.1.2.7 RESERVOIR DATA

(a) Dead Capacity

(b) Live Capacity

B.1.3 GAS POWER STATIONS

For SSGS – Gas

B.1.3.1 GENERAL

i	Name of **Power Station.**
ii	Number and capacity of **Generating Units** (MVA).
iii	Ratings of all major equipments (Turbines, Alternators, Heat Recovery Boiler, Generator Unit Transformers etc.)
iv	Single line Diagram of **Power Station** and switchyard.
v	Relaying and metering diagram.
vi	Neutral Grounding of **Generating Units.**
vii	Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors)
viii	Earthing arrangements with earth resistance values.
ix	Start up Engine
x	Turbine Details

B.1.3.2 PROTECTION AND METERING

i	Full description including settings for all relays and protection systems installed on the Generating Unit, Generator unit Transformer, Auxiliary Transformer and electrical motor of major equipments listed, but not limited to, under Sec. 3 (General).
ii	Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, Tie circuit breakers, and incoming circuit breakers.
iii	Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System.
iv	Most probable fault clearance time for electrical faults on the User's System.
v	. Full description of operational and commercial metering schemes.

B.1.3.3 SWITCHYARD

In relation to interconnecting transformers:

i	Rated MVA.
ii	Voltage Ratio

iii	Vector Group.
iv	Positive sequence reactance for maximum, minimum, normal Tap.(% on MVA).
v	Positive sequence resistance for maximum, minimum, normal Tap.(% on MVA).
vi	Zero sequence reactance (% on MVA).
vii	Tap changer Range (+% to -%) and steps.
viii	Type of Tap changer. (off/on load).

In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of Connection:

i	Rated voltage (kV).
ii	Type of circuit breaker (MOCB/ABCB/SF6).
iii	Rated short circuit breaking current (kA) 3 phase.
iv	Rated short circuit breaking current (kA) 1 phase.
v	Rated short circuit making current (kA) 3 phase.
vi	Rated short circuit making current (kA) 1-phase.
vii	Provisions of auto reclosing with details. Lightning Arresters - Technical data 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 synchronising a Generating Unit from de-synchronization.
ii	Minimum time between synchronizing different Generating Units in a Power Station.
iii	The minimum block load requirements on synchronizing.
iv	Time required for synchronizing a Generating Unit for the following conditions: 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 33kV bus at Grid Sub-station detailing:

(a)	Name of Sub-station.
(b)	Power Station connected.
(c)	Number and length of circuits.
(d)	Interconnecting transformers.
(e)	Sub-station bus layouts.
(f)	Power transformers.
(g)	Reactive compensation equipment.

ii. Sub-station layout diagrams showing:

(a)	Bus bar layouts.
(b)	Electrical circuitry, lines, cables, transformers, switchgear etc.
(c)	Phasing arrangements.
(d)	Earthing arrangements.
(e)	Switching facilities and interlocking arrangements.
(f)	Operating voltages.
(g)	Numbering and nomenclature: 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/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 -12 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 WRPC OUTAGE PROGRAMME

(Affecting Transmission System)

Items	Due date / Time
MW, which will not be available as a result of Outage from Imports through external Connections.	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 **WRPC**	15th February each year
Release of finally agreed Outage plan	15th February each year

C- 2. GENERATION SCHEDULING DATA

REFER TO CHAPTER -9: SCHEDULE AND DESPATCH CODE

C-3 CAPABILITY DATA

REFER TO:

CHAPTER -10: FREQUENCY AND VOLTAGE MANAGEMENT CODE

For SSGS

Item	Due date / Time
Generators and IPPs shall submit to SLDCup-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 -10: 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 -11: 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 -13 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 **Connection**

APPENDIX D: PROTECTION DATA

REFER TO:

CHAPTER -16 – 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 – 17 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 –4 RESOURCE ADEQUACY AND SYSTEM PLANNING CODE

General Policy

The State Transmission System planning and generation expansion planning shall be in accordance with the provisions of Manual on Transmission Planning Criteria issued by CEA and other guidelines. However, some planning parameters of the State Transmission System may vary according to directives of MPERC.

Planning Criterion

(a) The planning criterion is based on the security philosophy on which ISTS and State Transmission System has been planned. The security philosophy shall be as per Manual on Transmission Planning Criteria and other CEA guidelines. The general policy shall be as detailed below:

(i) As a general rule, the ISTS shall be capable of withstanding and secured against the following contingency outages without necessitating load shedding or rescheduling of generation during Steady State Operations:

- Outage of a 132kV D/C line or,
- Outage of a 220kV D/C line or,
- Outage of a 400kV S/C line or,
- Outage of a single Interconnecting Transformer, or,
- Outage of one pole of HVDC Bipole line, or,
- Outage of a 765kV S/C line.

(ii) The above contingencies shall be considered assuming a pre-contingency system depletion (Planned Outage) of another 220kV D/C line or 400kV S/C line in another corridor and not emanating from same sub-station. All the generating Units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified.

(b) The ISTS/STS shall be capable of withstanding the loss of most severe single system in feed without loss of stability.

(c) Any one of these events defined above shall not cause:

i	Loss of supply
ii	Prolonged operation of the system frequency below and above specified limits
iii	Unacceptable high or low voltage
iv	System instability
v	Unacceptable overloading of ISTS/STS elements

APPENDIX G SITE RESPONSIBILITY SCHEDULE

REFER TO: CHAPTER – 5: CONNECTION CODE

Item of Plant/ Apparatus	Plant Owner	Safety Responsibility	Control Responsibility	Operation Responsibility	Maintenance Responsibility	Remarks
.....kV Switchyard						
All equipment including bus bars						
Feeders						
Generating Units						

Name of Power Station/Sub-Station

Site Owner:

Tel. Number:

Fax Number:

APPENDIX H: INCIDENT REPORTING

REFER TO:

CHAPTER – 15: Reports

Operational Event/ Incidence reporting

FLASH REPORT : SLDC/STU/USERS/TRANSIMISSION LICENSEE/GENERATORS			
Agency Name/Month-Year/GD or GI- Number			
Name of Incident: .			
1. Date and Time:			
2. Antecedent Conditions			
I. Frequency of NEW Grid/SR Grid			
Event	**Frequency**	**Time(hh:mm)**	
Pre incident			
Post Incident			
II. Demand Met - MW			
State Generation - MW			
State Load - MW			
3. Event Description: Event and Likely cause as reported by SLDC./State Entities and as observed.			
4. Lines/ICT/Units tripped and Restoration			
Lines/ICT/Unit Tripped	**Load prior to fault**	**Tripping time**	**Restoration Time**
5. Areas Affected By Disturbance :			
6. Load Loss :			
7. Generation Loss :			
8. SUPPLY RESUMED FROM			

APPENDIX -I: REQUIRED DETAILS OF APPLICANT FOR CONNECTIVITY OF PROJECT WITH INTRA STATE TRANSMISSION SYSTEM

REFER TO:

CHAPTER - 5: CONNECTION CODE

Sl. No.	PARTICULAS	DESCRIPTION
1	Name & Address of the company with Registered Office, Telephone / Mobile No., Fax No. and E-mail address.	
2	Name, Designation and Address of the Developer/ Person-in charge, Telephone/Mobile No., Fax No. and Email address	
3	Location (Village, Tehsil, District) of the project Site with Geographical Map (showing longitude and latitude of the project location) and KMZ file indicating the location of the project	
4	Type of Project : (Wind/Solar/Captive/Other)	
5	Project Capacity (in MW)	
6	Schedule Timeline of Commissioning of the Project	
7	Sub-station from where connectivity is desired and distance from the project site	
8	Voltage Level at which connectivity is required (kV)	
9	No. of units and capacity of power plant (in MW) and Expected date of commissioning of the project.	
10	Complete Technical details of Wind/Solar power plant including DPR of the project	
11	Copy of Detailed Project Report (DPR) of the project including SLD & Layout of Proposed Plant. The grant of grid connectivity will be subject to compliance of CEA Safety Regulations and amendments thereof.	
12	Details of land acquisition along with location of pooling sub-station of project marked on the Patwari Map with Coordinates (Longitude/Latitude)	
13	Copy of registration of the project with MPNRED, Bhopal (Nodal agency for renewable projects in MP) / Copy of MoU between Developer & GoMP.	
14	Copy of the Comfort Letter / Wind Power Development Agreement (WPDA) executed with MP New and Renewal Energy Department (MPNRED)	
15	Copy of your RE project registration certificate issued by CEA, GoI, New Delhi as Renewable Energy Project registry is maintained by CEA, GoI. The CEA registration can be done through e-portal.	
16	Final clearance / sanction from MPNRED compliance report	
17	Name, address & location of the beneficiary of the project	
18	Point of drawal of the beneficiary	
19	Copy of PPA between Project Developers & Beneficiaries	
20	Whether applying for LTOA / MTOA	
21	Copies of the Statutory clearance obtained from the State Govt./ Central Govt. including MPNRED Registration, CEA Registration, Valid title of land, Forest clearance, Environmental clearance, Clearance from Urban/ Rural bodies, Power line clearances, Clearance from Highways/ Aviation & Roads/ concerned authorities like Gas pipelines, water pipeline or any other communication network in making interference etc. as and when applicable.	

APPENDIX -J: THIRD PARTY PROTECTION SYSTEM CHECKING & VALIDATION TEMPLATE FOR A SUB-STATION

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 tripping's (in last one year) and details of protection operation

(viii) Previous Relay Test Reports

(ix) Overall single line diagram (SLD)

(x) AC aux SLD

(xi) DC aux SLD

(xii) SAS architecture diagram

(xiii) SPS scheme implemented (if any)

(b) The preliminary report shall inter-alia contain the following:

TABLE: FORMAT OF PRELIMINARY REPORT

S.No.	Issues	Remarks
1	Recommendation of last protection checking and validation	Status of works and pending issues if any
2	Review of existing settings at sub-station	Recommended Action
3	Disturbance Recorder out available for last 6 tripping's (Y/N)	Recommended Action
4	Chronic reason of tripping, if any	Recommended Action
5	Major non-conformity / deficiency observed	Recommended Action

(c) The relay configuration checklist for available power system elements at station:

(i) Transmission Line

(ii) Bus Reactor/Line Reactor

(iii) Inter-connecting Transformer

(iv) Busbar Protection Relay

(v) AC auxiliary system

(vi) DC auxiliary system

(vii) Communication system

(viii) Circuit Breaker Details

(ix) Current Transformer Details

(x) Capacitive Voltage Transformers Details

(xi) Any other equipment/system relevant for protection system operation

(d) The minimum set of points on which checking and validation shall be carried out is covered in this Regulation. The detailed list shall be prepared by checking and validation team in consultation with concerned entity, 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 Overcurrent/Backup Earth fault/ Breaker Failure
f. Status of Oil Temperature Indicator/Winding Temperature Indicator / Bucholz/Pressure Release Device etc.
g. Relay connected to Trip Coil-1 or 2 or both
h. CT ratio and PT ratio
i. Feed from DC supply-1 or 2
j. Connected to dedicated CT core (mention name)
k. Other requirements for protection checking and validation

(iii) Busbar Protection Relay

a. Busbar and redundant relay make and model
b. Type of Busbar arrangement
c. Zones
d. Dedicated CT core for each busbar protection (Yes/No)
e. Breaker Failure relay included (Yes/No), if additional then furnish make and model
f. Trip issued to both Busbar protection in case of enabling
g. Isolator indication and check relays
h. Other requirements for protection checking and validation

(iv) AC auxiliary system

a. Source of AC auxiliary system
b. Supply changeover between sources (Auto/Manual)
c. Diesel generator (DG) details

d. Maintenance plan and supply changeover periodicity in DG

e. Single Line Diagram

f. Other requirements for protection checking and validation

(v) DC auxiliary system

a. Type of Batteries (Make, vintage, model)

b. Status of battery Charger

c. Measured voltage (positive to earth and negative to earth)

d. Availability of ground fault detectors

e. Protection relays and trip circuits with independent DC sources

f. Other requirements for protection checking and validation

g. Communication system

(i) Mode of communication for Main-1 and Main-2 protection

(ii) Mode of communication for data and speech communication

(iii) Status of PLCC channels

(iv) Time synchronization equipment details

(v) OPGW on geographically diversified paths for Main-1 and main-2 relay

(vi) Other requirements for protection checking and validation

(vi) Circuit Breaker Details

a. Details and Status

b. Healthiness of Tripping Coil and Trip circuit supervision relay

c. Single Pole/Multi pole operation

d. Pole Discrepancy Relay available(Y/N)

e. Monitoring Devices for checking the dielectric medium

f. Other requirements for protection checking and validation

(vii) Current Transformer (CT)/Capacitive Voltage Transformer (CVT) Details

a. CT/CVT ID name and voltage level

b. CT/CVT core connection details

c. Accuracy Class

d. Whether Protection/Metering

e. CT/CVT ratio available and ratio adopted

f. Details of last checking and validation of CT/CVT healthiness

g. Other requirements for protection checking and validation

h. Other protections: Direction earth fault, negative sequence, over current, over

voltage, over frequency, under voltage, under frequency, forward power, reverse power, out of step/power swing, HVDC protection etc.

3. SUMMARY OF CHECKING:

The summary shall specifically mention minimum following points:

(i) The settings and scheme adopted are in line with agreed protection philosophy or any accepted guidelines (e.g. Ramakrishna guidelines or CBIP manual based).

(ii) The deviations from the RPC protection philosophy, if any and reasons for taking the deviations shall be recorded.

(iii) All the major general deficiency shall be listed in detail along with remedial recommendations.

(iv) The relay settings to be adopted shall be validated with simulation based or EMTP studies and details shall be enclosed in report.

(v) The cases of protection mal-operation shall be analysed from protection indices report furnished by concerned utility, the causes of failure along with corrective actions and recommendations based on the findings shall be noted in the report.

APPENDIX -K: REACTIVE POWER COMPENSATION

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 Intra-State Transmission system.

(b) The charge for VArh shall be approved by the Commission vide separate order / notification from time to time. However, the Reactive Power Compensation (VArh) for RE generators shall be governed with tariff Orders issued by the Commission for respective category time to time.