MERC

MAHARASHTRA ELECTRICITY REGULATORY COMMISSION

EXPLANATORY MEMORANDUM

ON

DRAFT MAHARASHTRA ELECTRICITY REGULATORY COMMISSION (STATE GRID CODE) REGULATIONS, 2020

March 2020

Table of Contents

List of Tables

List of Figures

List of Acronyms

AMR	Automatic Meter Reading
AEC	Auxiliary Energy Consumption
AGC	Automatic Generation Control
APTEL	Appellate Tribunal for Electricity
AUL	Average Unit Loading
AVR	Automatic Voltage Regulator
BESS	Battery Energy Storage System
CE	Chief Engineer
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
COD	Commercial Operation Date
CSGS	Central Section Generating Stations
CT	Current Transformers
CTU	Central Transmission Utility
DC	Declared Capacity
df/dt Relay	Rate of Change of Frequency Relay
DSM	Deviation Settlement Mechanism
EA 2003	Electricity Act, 2003
EHV	Extra High Voltage
EHV SS	Extra High Voltage Substation
F&S	Forecast and Scheduling
FBC	Fluidized Bed Combustion
FGMO	Free Governor Mode of Operation
FTR	Frequency Trip Relays
G<>T	Generator to Transmission
GCC	Grid Coordination Committee
HVDC	High Voltage Direct Current
Hz	Hertz
ICT	Inter- Connecting Transformer
IEGC	Indian Electricity Grid Code
InSGS	Inter State Generating Stations
InSTS	Inter State Transmission System
ISGS	Inter-State Generating Stations
kV	kilovolt
MCCC	Metering and Communication Coordination Committee
MCR	Maximum Continuous Rating
MEGC	Maharashtra Electricity Grid Code
MERC	Maharashtra Electricity Regulatory Commission
MOD	Merit Order Despatch
MoP	Ministry of Power, Govt. Of India
MSLDC	Maharashtra State Load Despatch Centre
MTC	Maharashtra Transmission Committee
MVAr	Mega Volt Ampere Reactive

MW	Mega Watt
MYT	Multi-Year Tariff
NEP	National Electricity Policy
NLDC	National Load Despatch Centre
OA	Open Access
OCC	Operation Coordination Committee
PCC	Protection Coordination Committee
PPA	Power Purchase Agreement
RE	Renewable Energy
RGMO	Restricted governor mode of operation
RLDC	Regional Load Despatch Centre
RPC	Regional Power Committee
RSD	Reserve Shut Down
S&D	Scheduling and Despatch
SHR	Station Heat Rate
SLD	Single Line Diagram
SLDC	State Load Despatch Centre
SoR	Statement of Reasons
SRS	Site Responsibility Schedule
STU	State Transmission Utility
T<>D	Transmission to Distribution
TMCR	Turbine maximum continuous rating
TSU	Transmission System User
UHV	Ultra High Voltage
URS	Un-Requisitioned Surplus
VArh	Volt Ampere Reactive Hour
VWO	Valve Wide Open

DRAFT MAHARASHTRA ELECTRICITY REGULATORY COMMISSION (STATE GRID CODE) REGULATIONS, 2020

1 Background

The Electricity Act, 2003 (EA 2003) (36 of 2003) (hereinafter referred to as "the EA 2003") mandates the Maharashtra Electricity Regulatory Commission (MERC) (hereinafter referred to as "the Commission") under clause (h) sub-section (1) Section 86 to specify the State Electricity Grid Code consistent with the Central Electricity Regulatory Commission's (CERC) Indian Electricity Grid Code (IEGC).

The Commission notified (No. MERC/Legal/151/State Grid Code/0338) the Maharashtra Electricity Regulatory Commission (State Grid Code) Regulations, 2006 in 2006 and came into effect from 1 April 2006. The SGC 2006 was introduced in line with the IEGC Regulations, 2006.

The CERC notified the IEGC 2010 on 28 April 2010 and came into force from 3 May 2010 superseding the IEGC Regulation, 2006. Till date, the CERC has issued six amendments to the principal regulations from time to time. The details of those amendments are as below.

Table 1: Chronology of IEGC regulations amendments

Particulars	Date	Details of Amendment
1st Amendment 2012	5 March 2012	• Restricted governor mode of operation (RGMO) related provisions introduced
2nd Amendment, 2014	6 January 2014	• Frequency band for grid operation revised from "49.7-50.2 Hz" to "49.90-50.05 Hz" • Other relevant changes in S&D Code in line with CERC DSM Regulations, 2014.
3rd Amendment, 2015	7 August 2015	• Revisions related to F&S framework
4th Amendment, 2016	6 April 2016	• Reducing Technical Minimum to 55% • Compensation mechanism for operation of TPS below 70% up to 55% • Reserve shut down on scheduling below technical minimum schedule • Procedure and mechanism for declaration of commercial operation date (COD)
5th Amendment, 2017	12 April 2017	• Addition of spinning reserve definition, Un-requisitioned Surplus (URS) • Relevant changes for the introduction of ancillary services
6th Amendment, 2019	12 December 2019	• Real-time market related provisions

In view of the above amendments to the IEGC, 2010, the Commission finds it appropriate to review its State Grid Code Regulations, 2006 to align the same with the provisions of the IEGC and its amendments.

2 Review of State Grid Code, 2006

2.1 Review of existing relevant Regulations of the Commission

The Commission while reviewing its State Grid Code, 2006 has considered the provisions of following Regulations/Codes and Guidelines/Procedures:

1. MERC DSM Regulations, 2019
2. MERC MYT Regulations, 2019
3. Scheduling and Despatch Code, 2019
4. Metering Code, 2019
5. DSM Procedure, 2019
6. MERC-Guidelines for the Operation of Merit Order Despatch (MOD) - April 2019

2.2 Review of relevant Regulations/Report/Procedure of the Central Commission

1. CERC IEGC 2010 and Subsequent Amendments
2. CERC order No. L-1/219/2017-CERC dated 05 May 2017
   (i) Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of central generating stations, inter-state generating stations and other generating stations and for taking such units under reserve shut down on scheduling below technical minimum schedule
   (ii) Mechanism for compensation for degradation of heat rate, Aux consumption and secondary fuel oil consumption, due to part load operation and multiple start/stop of units
3. CERC Tariff Regulations, 2019
4. CERC (Planning, Coordination and Development of Economic and Efficient ISTS by CTU and other related matters) Regulations, 2018
5. CERC (Communication System for inter-State transmission of electricity) Regulations, 2017.
6. Report of the Committee on Spinning Reserves in India, 2015 published by CERC
7. Report of Expert Committee constituted by the CERC for review of IEGC - January,2020
8. Report of Technical Committee constituted by MoP for Large scale RE integration – October,2016

2.3 MERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2019

The Commission has notified MERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 on 1 March 2019. As per the provisions of MERC DSM Regulations, MSLDC shall prepare the procedure for scheduling and despatch (S&D) and procedure for the computation of charges for deviation and additional charges for deviation and energy accounting as per the principles specified in the MERC DSM Regulations, 2019.

2.4 Scheduling and Despatch Code, 2019

MSLDC prepared draft Scheduling and Despatch (S&D) Code and draft Deviation Settlement and Energy Accounting Procedure and published for stakeholder's comments on its website on 9 May 2019 for stakeholder's suggestions/comments. MSLDC received the comments/suggestions from the stakeholders on the draft S&D Code and DSM procedure. Considering the stakeholder's comments/suggestion, MSLDC revised the Draft S&D Code and DSM Procedure appropriately and submitted to the Commission for approval on 20 August 2019. The Commission reviewed the draft S&D Code and DSM procedure submitted by the MSLDC and approved the S&D Code and DSM procedure on 11 November 2019 and directed to publish the approved copies on SLDC's website.

The S&D Code was prepared to facilitate MSLDC in discharging its responsibilities as per the provisions of State Grid Code, the S&D Code under IEGC and MERC DSM Regulations. The Code identifies the roles and responsibilities of Users and State Entities for the preparation and finalisation of the following by MSLDC:

(i) A day ahead Despatch Schedule for Sellers.
(ii) A day ahead Drawal Schedule for Buyers.
(iii) A load generation balance for State.

2.5 Metering Code, 2019

As per the provisions of MERC DSM Regulations and Statement of Reasons (SoR) to DSM Regulations, the Commission directed the STU to undertake the review of Metering Code under MERC State Grid Code, 2006. Accordingly, the STU constituted the Metering Code Committee under the convenorship of Chief Engineer (CE), STU. Metering Code Committee reviewed the existing Metering Code and prepared revised draft Metering Code in line with the provisions of the Central Electricity Authority (CEA) Metering Regulation, IEGC provisions and other relevant Regulations. The STU published the draft Metering Code on its website for stakeholder's comments. The comments/suggestions received from the stakeholders were discussed in the meetings of the Metering Committee. Considering stakeholder's comments and suggestion, the Metering Committee revised the draft Metering Code and submitted to the Commission for approval on 3 September 2019.

The Commission reviewed the draft Metering Code submitted by the STU and approved the draft Metering Code on 5 December 2019 and directed STU to publish the approved copies on STU’s website. This approved Metering Code shall be Part H of these Regulations and shall be read with MERC State Grid Code as may be required.

3 Provision of the Draft MERC Grid Code Regulations, 2020

3.1 Preamble

The State Grid Code aims to lays down the rules, guidelines and standards to be followed by the state entities and Users, of the Intra-State Transmission System (InSTS) to plan, develop, operate and maintain the InSTS as an integrated part of Western Region Grid System and National Grid, in the most efficient, reliable and economical manner, while facilitating a healthy competition in the generation and supply of electricity. This State Grid Code shall be known as Maharashtra Electricity Grid Code (MEGC) and shall contain the following parts, namely:

Part A: General

Part B: Planning Code

Part C: Connection Code

Part D: Operating Code

Part E: Scheduling and Despatch Code

Part F: Communication Code

Part G: Protection Code

Part H: Metering Code

Part I: Miscellaneous

3.2 PART A: General

This part largely deals with the scope and application of MEGC Regulations, 2020 amongst its Users and Stakeholders and re-constitution of Grid Coordination Committee (GCC) with the introduction of Sub-Committees under GCC as per the functional requirement for smooth implementation and monitoring of MEGC. The general provisions also include proceedings of the Committee/Sub-Committees Meetings and MEGC review.

The MEGC brings together a single set of technical and commercial rules, encompassing all the Utilities connected to/or using the InSTS and governs the relationship between the various Users of the InSTS, State Load Despatch Centre (SLDC) as well as the Regional Load Despatch Centres (RLDCs).

3.3 Objectives of the MEGC

a) Documentation of the principles and procedures to define the relationship among various Users of the InSTS and to promote co-ordination amongst all Users, STU/SLDC and CTU/RLDC, NLDC, Regional Power Committee (RPC) and CEA in any proposed development of the InSTS.

b) Facilitation of optimal operation of the grid, facilitation of coordinated and optimal maintenance planning of generation and transmission facilities in the grid and facilitation of development and planning of economic and reliable State Grid.

c) By specifying optimum design and operational criteria to assist the Users in their requirement to comply with License obligations; hence, ensuring that a system of acceptable quality is maintained.

To set out the various procedures/mechanisms in line with the provisions of the Grid Code, DSM Regulations and MYT Regulation such as Declared Capacity (DC) Demonstration, COD declaration procedure, Reactive Power Pricing Mechanism and implementation of revised technical minimum for thermal generating stations.

To facilitate large-scale grid integration of solar and wind generating stations while maintaining grid stability and security envisaged under the State Grid Code.

3.4 Scope of Regulation and Extent of Application

The MEGC Regulations shall be applicable to:

a) Intra-State Generators connected to InSTS;

b) Transmission Licensee in the State including STU;

c) Maharashtra SLDC and its Sub-SLDC;

d) Distribution Licensees including Deemed Distribution Licensees, Indian Railways;

e) Open Access Consumers, EHV Consumers connected to InSTS.

All the Users who are connected to and/or use the InSTS shall comply with the provisions of State Grid Code.

3.5 Re-Constitution of GCC

The GCC was constituted under the MERC State Grid Code, 2006 for facilitating the implementation of the State Grid Code and recommending remedial measures in case of any difficulty during implementation and review of the State Grid Code.

Considering the involving developments in the State Power Sector since 2006, such as Transmission Open Access, Deemed Distribution Licensees, Trading, RE Developments, Forecasting and Scheduling of RE, Deviation Settlement Mechanism, the number of InSTS Stakeholders/Users have been increased. The roles and responsibilities of these stakeholders have also been increased. The increased number of issues related to the planning and operation of InSTS shall be discussed and addressed in the GCC. Accordingly, it is appropriate to re-constitute the GCC with extending the scope to accommodate more number of stakeholders of the GCC.

The GCC shall be the apex body for implementation of MEGC and constitute functional committees to coordinate various activities specified in the MEGC. The GCC shall comprise of the following members:

a) Director, State Transmission Utility (STU) - Chairperson of GCC;

b) Executive Director/Chief Engineer, MSLDC - Member;

c) Representative of STU - Member Convener;

d) Representative of a State-owned Generating Company - Member;

e) Representative of State-owned Distribution Licensees in the State – Member;

f) Representative of the Indian Railways in the State – Member;

g) Representative of Western Region Load Despatch Centre – Member;

h) Representative of Western Region Power Committee – Member;

i) Representative of Maharashtra Energy Development Agency – Member;

j) Representative of renewable generators in the State - Member;

k) Representative of Transmission Licensees in the State, other than the STU not below the rank of Chief Engineer or General Manager - Member;

l) Representative of privately-owned Distribution Licensees including deemed Distribution Licensees– Member;

m) Representative of private-owned Generating Companies including IPPs and CPPs in the State not below the rank of Chief Engineer or General Manager - Member;

n) Representative of Long -Term OA Consumers connected to InSTS in the State – Member;

o) Such other persons as may be nominated by the Commission.

The members referred to in clauses (j) to (p) above shall be selected in rotation among all such organizations in the State. The term of each such member, selected in rotation, shall be two years. The members nominated by each of the organization shall be holding a senior position in their respective organization.

To oversee the implementation of the MEGC provisions, under the ambit of GCC, functional Sub-Committees shall be constituted to support the GCC.

3.6 Roles and Responsibilities of GCC

a) Facilitating the implementation of these Regulations and procedures developed under these Regulations;

Assessing and recommending remedial measures for issues that arise during the implementation of these Regulations and procedures developed under these Regulations. The GCC may formulate suitable procedures, code of operation, manual and guidelines or revise the such procedures/guidelines/manuals/code under these Regulations by undertaking stakeholders consultation and shall submit to the same to Commission for approval.

b) Review of the MEGC, in accordance with the provisions of these Regulations and propose amendments required if any to the Commission;

c) Other matters as may be directed by the Commission from time to time.

3.7 Functional Committees Under GCC

The MEGC Regulations, 2020, proposes following functional Sub-Committees for assisting the GCC for dealing with the specific issues and monitoring various activities under the Grid Code. The members of the GCC shall discuss and decide the members of the functional Committees and Terms of Reference of the Committees.

The details of the proposed Sub-Committees and their key functionalities are shown in the table below:

Table 2: Details of the proposed Sub-Committees and their key functionalities

Functional Committees under GCC	Frequency of Meeting	Key Functions
Maharashtra Transmission Committee (MTC)	Once every six months	• Co-ordinate system planning, maintenance schedule and contingency plan of InSTS. • Review of existing interconnection equipment for alteration, addition, if necessary. • Review the load forecast (long term). • Review and finalise the proposals. • Prepare quarterly reports detailing the execution of various plans. • Study and suggestion of the projects under Tariff based Competitive Bidding. • Study and propose new technology in the Transmission. • Monitor the projects under execution. • Analyse the reasons for delay and way forward. • Suggestion to the GCC for timely execution of the projects. • Any other function as directed by the GCC.

Functional Committees under GCC	Frequency of Meeting	Key Functions
Operation Coordination Committee (OCC)	Once every six months	• Review and analyse the grid disturbances and system restoration procedure. • Review the reactive compensation mechanism. • Review and finalize outage plan. • Review the demand disconnection mechanism. • Review the installation of Disturbance Recorders, Event Loggers, Frequency Trip Relays (FTR), Rate of Change of Frequency(df/dt) relays etc. • Review and study the implementation of governor mode of operation for the generating stations. • Any other function as directed by the GCC.
Protection Coordination Committee (PCC)	Once every six months	• Ensure compliance of Protection Code. • Specify the minimum protection requirements. • Deliberate and decide various protection settings, testing procedure and periodicity. • Review the requirement for upgradation of protection schemes. • Analyse the failure of the protection system in case of major grid disturbance • Review the suggestion of Users for revision of Protection Code. • Any other function as directed by the GCC.
Metering and Communication Coordination Committee (MCCC)	Once every six months	• Ensure compliance of Metering Code; • Review deviations in the existing Current Transformers (CT) and PTs/CVTs from the minimum specifications. • Deliberate and decide the issues related to metering and metering failure for DSM account and energy account. • Review and propose amendments in the metering arrangement. • Any other function as directed by the GCC.

3.8 Roles and Responsibilities of Various Entities and InSTS Users

MEGC Regulations, 2020 specifies the roles and responsibilities of various State Entities, Users connected to the InSTS. The proposed provisions are in-line with the provisions of the EA 2003 and CERC IEGC 2010. The roles and responsibilities provided in the Grid Code are not exhaustive. All the State Entities and Users shall abide by the instructions of SLDC in the interest of smooth grid operation. The key provisions of roles and responsibilities are shown in the table below:

Table 3: Roles and responsibilities of Stakeholders

Name of Stakeholder	Roles and Responsibilities of Stakeholder
Role of State Transmission Utility (STU)	• To undertake transmission of electricity through InSTS • To discharge all functions of InSTS planning • Co-ordination relating to InSTS with the Central Transmission Utility (CTU), State Government, Generating Companies, Regional Power Committee, Central Electricity Authority and Licensees • To ensure development of an efficient, co-ordinated and economical InSTS • To provide non-discriminatory open access to (i) any licensee or generating company on payment of the transmission charges (ii) any consumer as and when such open access is provided by the State Commission.
Role of SLDC	• Apex body to ensure integrated operation of the power system • Responsible for optimum S&D of electricity within a State • Monitor grid operations • Keeping accounts of the quantity of electricity transmitted • Carrying out real-time operations for grid control • Despatch of electricity through secure and economic operation • Directions and exercise such supervision and control over every licensee, generating company, generating station, sub-station • Ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation • Shall comply with the directions of the RLDC • Accord concurrence or no objection or a prior standing clearance for inter-state bilateral and collective short-term open access transactions • Issue certificates such as availability of the sellers, or any other certificate as may be directed by the Commission from time to time.
Role of Transmission Licensee	• Build, maintain and operate an efficient, co-ordinated and economical InSTS or ISTS • Discharge other functions assigned to it as per Section 40 of the EA 2003

Name of Stakeholder	Roles and Responsibilities of Stakeholder
Role of Distribution Licensees	• Develop and maintain an efficient, co-ordinated and economical distribution system in its area of supply • Provide non-discriminatory open access to its distribution system • Discharge the functions as stated in Section 42 of the EA, 2003
Role of Generating Company	• Provide scheduling of generation. • Inform the STU and SLDC about the contracts entered into with different parties for exporting power. • Follow relevant provisions of the State Grid Code • Assist the SLDC in real-time operation and control of the system.
Role of Qualifying Co-Ordinating Agency (QCA)	• To collect, verify, ascertain and maintain records of generator-wise static project information for wind turbine/solar inverter, • To coordinate with RE Generator(s) for the forecasts/ schedule(s), • To communicate aggregate forecast(s)/schedule(s) to SLDC (day ahead) and revision of schedules during intra-day operations in line with the provisions of F&S Regulations, • To receive instructions from SLDC for curtailment, real-time operations and cause to implement such SLDC instructions, • To facilitate with STU/SLDC for establishment of facilities for communication of meter data/RTU data as required, • To receive Statements of Energy Account/ Deviation Account and Deviation Charge Bill Amount from SLDC as per provision of F&S Regulations, • To prepare and share Generator-wise 'Statement of De-Pooling Account' as per provision of F&S Regulations, • To receive/make payments from/to RE Generator(s) and to make/receive payments to the State Deviation RE Pool Account as per provision of F&S Regulations,

4 Part B: Planning Code

4.1 Objective of Planning Code

The objective of Planning Code of the MEGC Regulations, 2020 is in line with the IEGC as below:

a) To specify the principles, procedures, technical and design criteria to be adopted by STU for planning and development of InSTS and inter-state links.

b) To promote coordination amongst all Users, STU/SLDC and CTU/RLDC, NLDC, WRLDC, WRPC and CEA in any proposed development of the InSTS.

c) To provide methodology and information exchange amongst Users, STU/SLDC, CTU/RLDC, RPC/SPC, NLDC and CEA in the planning and development of the InSTS.

d) Probabilistic assessment by the designated agency of a State of its future demand pattern under different scenarios;

e) Adequacy of generation resources taking account loss of load probability and energy not served as specified by CEA;

f) Adequate generation reserves and demand response for maintaining grid stability;

g) Validation of adequacy of transmission resources through system studies considering economic despatch under various demand and generation scenarios including must run generation;

h) Validation of adequate power transfer capability to be carried out for the entire grid in a comprehensive manner by STU;

i) Validation of adequate power transfer capability to be carried out by STU.

4.2 Applicability of Planning Code within InSTS

STU and Transmission Licensees within the State shall be guided by Planning Code for the preparation of Transmission Planning. The EA 2003, Clause (b) sub-section 2, Section 39 empowers the STU to discharge all functions of planning and coordination of State entities connected to the InSTS. The Code is applicable to all the InSTS Users within the State seeking or intend to seek the InSTS connectivity.

4.3 Nodal Agency for Implementation of Planning Code

STU shall be the nodal agency for implementation and compliance monitoring of Planning Code with the help of Transmission Licensees in the State. STU shall endeavor to ensure that the schemes are executed in accordance with the time frame mentioned in the Transmission Plan formulated by the STU. Implementation of projects shall be closely monitored by the Transmission Project Execution and Monitoring Committee constituted under these Regulations.

4.4 Key Regulations/references to be considered for InSTS Planning

This Code specifies the principles, procedures and criteria to be considered for planning and development of InSTS. The provisions of Planning Code are formulated considering the provisions of the IEGC and the Regulations of the Central Electrical Authority (CEA). Following are the key regulations considered preparing the Planning Code.

a) CEA (Technical Standards for Connectivity of the Grid) Regulations, 2007

b) CERC (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by CTU and other related matters) Regulations, 2009.

c) CEA (Grid Standards) Regulations, 2010

d) CEA's National Electricity Plan for Transmission,2019.

The Commission has introduced additional provisions in the Planning Code in line with the above Regulations/Manuals. The provisions of Planning Code mandate the STU that, while preparing the Transmission Planning Code, it shall introduce following sections as mentioned below and discuss the same in the Maharashtra Transmission Committee (MTC) to be constituted under the aegis of GCC.

a) Generation Evacuation Planning

b) Load Projection Planning

c) Interconnection Planning

d) Inter-State Transmission Connection Planning

The Commission has also proposed to consider following criteria while planning the InSTS with the provisions of the CEA's National Electricity Plan (Volume -I and II) 2019:

a) EHV Substation Planning Criteria

b) Additional Planning Criteria for Wind and Solar Projects

c) Capacity Factor

d) Additional Planning Criteria for HVDC Transmission System

The STU shall prepare a perspective transmission system plan based on the data obtained from the Users and internal sources for:

a) Short term period, i.e., up to 5 years;

b) Medium term period, i.e., up to 10 years; and

c) Long term period, i.e., up to 15 years.

4.5 Planning Criteria:

Transmission planning shall be based on the two main criteria viz. technical criteria and financial criteria. The requirement of any new scheme, InSTS line, substation, latest technologies such a HVDC, EHV substations more than 400kV level needs to be studied by STU or concerned transmission licensee both for technical and financial aspects.

Technical Planning Criteria:

Planning criterion shall be based on the security philosophy on which the InSTS has been planned considering past experience of STU and Users, future plan of various State Government agencies etc. The transmission planning philosophy shall be guided by "Manual on Transmission Planning Criteria, 2013" published by the Authority, National Electricity Plan including its amendments thereof, and other guidelines as specified by the Authority and amended from time to time:

Provided that STU shall carry out appropriate system studies while developing the transmission system plan.

InSTS Plan should ensure that augmentation of the grid results in optimal utilization of the infrastructure. To that effect based on the technical studies conducted by STU should assure that the additional proposed transmission element should not result in overall average utilization of the grid by less than 40% for off peak load.

It should also be ensured that the appraisal of the proposed additional transmission element is done on techno commercial basis as per the prudent financial analysis.

In case a proposal is meant to support the National system, GCC should duly record such a proposal for sponsoring the same for the same to become part of ISTS.

Financial Planning Criteria:

While developing transmission system plan covering addition of new transmission system element (transmission line or substation) or for augmentation of the capacity of existing transmission line or addition of transformer or bay, the STU shall provide due consideration to commercial aspects and cost implications thereof on arising on account of addition/augmentation of any transmission system element. For this purpose, STU shall be guided by but not limited to following commercial principles and parameters as outlined below:

a) Optimum utilisation of the existing capacity and planned capacity addition of the transmission system element

b) Economical and efficient development of transmission system element(s) to economise overall Return of Investment for transmission system

c) Equitable and fairness in recovery of the cost from the transmission system users

d) Coordinated development of transmission system elements, particularly with reference to inter-state/inter-regional transmission system elements vis-à-vis intra-state transmission system elements;

For operationalisation of the above financial criteria, STU shall develop and publish on its website zone-wise transmission capacity utilisation index for various transmission system elements (HVDC, 765 kV, 400 kV, 220 kV, 132 kV and below)

The GCC shall formulate methodology for computation of zone-wise transmission capacity utilisation index, collate relevant data, and shall publish such methodology alongwith relevant data on its website.

Prior to inclusion of any new transmission system element entailing capital outlay exceeding threshold limit of INR 100 Crore or such other threshold limit to be stipulated by the Commission from time to time, as part of transmission system plan, STU shall evaluate and present alternate options of meeting the User/Requester requirement (with or without transmission element, factoring optimal capacity expansion than sought for, or evaluate alternate technology options, consider deferment or prioritisation considerations etc) and accordingly undertake scenario analysis of various cases and present it to User/Requester in order to ensure economical and efficient development of transmission system element(s) to economise overall Return of Investment for transmission system as whole.

Prior to inclusion of any new transmission system element or augmentation of the capacity of existing transmission system element, as part of transmission system plan, the STU shall give due consideration to equitable and fairness in recovery of costs from concerned transmission system users (subject to prevalent pricing framework) and shall highlight the incremental cost recovery burden that would be added to transmission system users due to addition/augmentation of such new transmission system element and in case the capacity utilisation of such element does not take place as planned. For this purpose, the STU through (GCC/Maharashtra Transmission Committee i.e. MCC) shall expressly deliberate, highlight and record the viewpoints of transmission system users for addition/augmentation of transmission system elements, before incorporation of such transmission system element and finalisation of transmission system plan and annual rolling plan.

STU shall regularly assess the progress and utilisation of the inter-state and inter-regional transmission systems, their utilisation vis-à-vis intra-state transmission system planned capacity addition/augmentation to ensure coordinated development of transmission system elements. A period review of developments/progress shall facilitate STU to participate in the National/Regional Transmission Planning Committee meetings and put forth state perspective and highlight deficiencies which can avoid sub-optimal development/utilisation through timely interventions. The intra-state transmission schemes that are of strategic importance or entail inter-state/inter-regional features needs to be pursed to be covered as part of ISTS network for its cost recovery.

STU shall formulate Guidebook for operationalisation of the Planning Code covering detailed modalities for implementation of the financial planning criteria and technical planning criteria, information requirements from Users/Requesters, suitable forms/formats and periodic reporting/publication of zone-wise transmission utilisation index, within three months from notification of these Regulations.

4.6 Preparation of Transmission system plan by STU

Transmission system plan prepared by the STU shall consist of the following sections:

a) The executive summary of Transmission plan providing the location of existing and proposed EHT substations, connecting lines, number of bays at each voltage level with details of present occupancy and availability for future expansion.

b) Details of planning of new substations with spare bays at lower voltage levels and at the incoming side (Higher Voltage side) for future expansion.

c) Generation evacuation planning for the evacuation of the upcoming generation capacity deemed to be connected to InSTS including RE Generators;

d) Load projection planning shall deliberate transmission planning to meet the increasing demands from distribution licensee(s) and other Users including deemed distribution licensees;

e) Interconnection planning shall deliberate transmission planning for interconnection between a network for generation evacuation and load projection; and

f) InSTS connection planning shall deliberate transmission planning for the evacuation of power by the State from neighboring States or regions.

The Planning Code also provide criteria for

a) EHV Substation Planning

b) Additional Planning Criteria for Wind and Solar Projects

c) Additional Planning Criteria for HVDC Transmission System

The Planning Code also provides a protocol for sharing of planning data by InSTS Users for the preparation of InSTS Plan.

4.7 Transmission Planning Submission and Approval

Load forecasting is the primary responsibility of the Distribution Licensees within their area of supply. Distribution Licensees shall prepare Peak Demand and Energy Forecasts (duly assessing the requirements of Open Access, captive Users, energy efficiency measures, distributed generation within distribution license area) of their areas for each of the succeeding 10 years and submit the same annually, by 31st January to the STU. The concerned Transmission Licensees shall consider the load forecast of distribution licensees and plan for the addition of new substation(s) or new transmission line or augmentation of capacity of existing substation or transmission line and submit the proposal to STU for approval. The STU shall put up the proposal before the MTC for detailed scrutiny. While scrutiny of the proposals, MTC shall be guided by the transmission planning criteria specified by the Authority. MTC shall provide its recommendations to STU on each proposal submitted by transmission licensees.

STU while planning for addition of new substation(s) or new transmission line or augmentation of capacity of existing substation or transmission line, shall consider the recommendations/suggestions of GCC/MTC.

While preparing the transmission plan for the State, STU shall be guided by the Technical Standards and planning criteria specified/notified by the Authority**.**

Planning criteria shall be based on the security philosophy on which the InSTS has been planned considering past experience of STU and Users, future plan of various State Government agencies etc. The security philosophy shall be based on “Manual on Transmission Planning Criteria, 2013” published by the Authority and other guidelines as given by the Authority and as amended from time to time. STU may also carry out appropriate system studies while developing the transmission system plan.

The STU/transmission licensees shall submit the detailed investment plan to the Commission for approval.

STU shall carry out the yearly planning process corresponding to 5 years forward term for identification of major transmission system from the financial year immediately following the year in which it is published.

The transmission system plan shall be updated by the STU each year and published by 31 December each year. The transmission plans shall be updated every year to accommodate the revisions in the load projections and generation capacity additions.

4.8 Implementation of Transmission Plan

STU shall endeavour to ensure that the schemes are executed in accordance with the time frame mentioned in the Transmission Plan formulated by the STU. The execution of transmission projects shall be closely monitored by the MTC constituted under the aegis of the GCC.

Implementation related issue shall be discussed in the meetings of MTC/GCC as per the requirement and MTC/GCC shall also provide its recommendations for timely completion of the projects.

MTC shall submit its quarterly report of the status of ongoing transmission projects in the State with reference to STU transmission plan to the Commission through GCC.

4.9 Spinning Reserve Planning

Spinning Reserve means the Capacities which are provided by devices including generating station or units thereof synchronized to the grid and which can be activated on the direction of the System Operator and effect the change in active power. The National Electricity Policy (NEP) mandates that adequate reserves may be maintained to ensure secure grid operation:

"5.2.3 In order to fully meet both energy and peak demand by 2012, there is a need to create adequate reserve capacity margin. In addition to enhancing the overall availability of installed capacity to 85%, a <u>spinning reserve of at least 5%, at national level,</u> would need to be created to ensure grid security and quality and reliability of power supply."

In furtherance to the provisions relating to the requirement of Spinning Reserves in line with NEP, to facilitate-large scale integration of RE sources, balancing, deviation settlement mechanism and associated issues, the CERC constituted a Committee in 2015, under the chairmanship of Shri A.S. Bakshi, Ex-Member CERC, to examine the technical and commercial issues in connection with Spinning Reserves and evolve suggested regulatory interventions in this context.

The Committee submitted its final report to the CERC on 17 September 2015. The CERC vide its Order dated 13 October,2015 accepted the findings of the Committee. The key findings of the Committee are as below:

a) Spinning Reserves are required to be maintained of requisite quantum depending upon the grid conditions. Operation at constant frequency target of 50.0 Hz with constant area interchange should be the philosophy adopted.

b) The Spinning Reserve may be maintained, to start with at the regional level in a distributed manner.

c) Each region should maintain secondary reserves corresponding to the largest unit size in the region and tertiary reserves should be maintained in a decentralized fashion by each state control area for at least 50% of the largest generating unit available in the state control area.

d) The reserve requirement may be estimated by the nodal agency on day-ahead basis along with day ahead scheduling of all available generating stations.

e) Implementation of AGC is necessary along with reliable telemetry and communication. The AGC may be planned to be operationalised in the power system from 1.4.2017.

f) The reserves at the regional level, should be assigned to specific identified generating station or stations duly considering the various technical and commercial considerations including energy charges of the generating stations. The nodal agency should be empowered to identify the ISGS irrespective of type and size of the generating station for providing spinning reserve services and it should be mandatory for such generating stations to provide spinning reserve services.

g) The nodal agency may have the option of carrying such reserves on one or more plants on technical and commercial considerations and may withhold a part of declared capacity on such plants from scheduling. It could be in terms of % of declared capacity or in MW term as deemed fit.

h) A framework as specified in the Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 may be followed for the Spinning Reserve Services as well. The Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 may be amended to incorporate the necessary changes in this regard.

i) Going forward, a market based framework may be put in place from 1st April 2017 for achieving greater economy and efficiency in the system. A detailed study is required to be carried out before the market mechanism on spinning reserves is put in place.

The CERC in its Order dated 13 October,2015 also underscores that grid does not generate electricity and as such cannot be relied upon for meeting energy needs. Reserves and reserves alone can address this and the earlier the stakeholders realise this, the better it is for safe and secure system operation.

Reserves assume greater significance additionally in the wake of the goal of integration of largescale variable RE sources. With increasing penetration of variable and intermittent RE generation, flexible generation such as pumped storage hydro plants are needed. There is a need for more flexibility in the operation of conventional generation plants also and flexibility needs to be quantified, measured and duly compensated for.

The variability that can be predicted in the forecasts must be accounted for in planning flexible generation as well as tertiary reserves day-ahead and hour-ahead. Furthermore, balancing the uncertainty of RE power on a continuous basis necessitates a streamlined process for deploying spinning reserves. This would be effectively balancing the forecasting error in net load.

Accordingly, the CERC has directed as below:

i. *Chart out a road map for introduction of reserves in the country.*

ii. *For reliable and secure grid operation, to maintain continuous load-generation balance, to counter generation outages as well as unexpected load surges or crashes, and for large scale integration of variable renewable power, it is essential for the grid operators to have access to distributed Spinning Reserves which are dispatched taking due care of transmission constraints whenever required.*

iii. *The Commission reiterates the need for mandating Primary Reserves as well as Automatic Generation Control (AGC) for enabling Secondary Reserves.*

   a) *All generating stations that are regional entities must plan to operationalise AGC along with reliable telemetry and communication by 1st April, 2017. This would entail a one-time expense for the generators to install requisite software and firmware, which could be compensated for. Communication infrastructure must be planned by the CTU and developed in parallel, in a cost-effective manner.*

   b) *On the other hand, National/Regional/State Load Dispatch Centres (NLDC/RLDCs/SLDCs) would need technical upgrades as well as operational procedures to be able to send automated signals to these generators. NLDC /RLDCs and SLDCs should plan to be ready with requisite software and procedures by the same date.*

   c) *The Central Commission advises the State Commissions to issue orders for intra-state generators in line with this timeline as AGC is essential for reliable operation of India's large inter-connected grid.*

Further, the report of technical committee on large scale integration of RE, need of balancing, DSM and associated issued in April, 2016 also recommends the requirement of maintaining the Spinning Reserves at national level and reserve level. The reports specifically highlights that, the requirement of spinning reserves is not only for large scale RE integration. The spinning reserve requirement may be attributed to a host of factors such as unit outages, transmission line trippings, weather related uncertainties forecast errors etc. The report also discusses that, as a short-term solution spinning reserves may be identified in the existing plants by scheduling conventional generation upto only 95 % of the Installed Capacity and balance 5 % may be kept as spinning reserve.

Further, the recent report dated 14 January,2020 of the expert committee constituted by CERC for review of provisions of IEGC recommends that, it is desirable that reserves should be provided locally by the control area. The responsibility to provide reserve response should be shared by all Control Areas in a distributed manner in the interest of grid security and in a participative manner so that there is no tendency to pass on the responsibility to other entities. Only in exceptional cases where a control area doesn't have generation resources within the Control Area, the responsibility of frequency control response may be taken over by the LDC. However, it may be added that with the advent of new technologies such as Battery Energy Storage System (BESS), it may be possible to provide frequency response even without physical generation assets in its control area.

Proposal under MEGC, 2020:

In view of the recommendations of various reports of technical committee of MoP and expert committee of CERC, it is proposed that, appropriate spinning reserves needs to be maintained for reliable operation of State Grid. The Commission in its Scheduling and Despatch Code dated 11November,2019 has specified that, while giving the Schedule to Generators as per De-Centralized MoD Principles, the MSLDC shall maintain the spinning reserve margin in the Generator as and when specified by the Commission for management of ramp up as per the requirement of the Grid. Accordingly, the Draft MEGC proposes as below:

14.4.3 SLDC need to ensure maintenance of adequate Spinning Reserve Margin equivalent to 3% of the System Peak Demand (or such other percentage as specified by Commission) for the purpose of day-ahead load generation balance and intra-day operations. For preparation of day ahead Schedule of Generators as per De-Centralised MoD Principles, the SLDC shall maintain the spinning reserve margin in the specified Generator(s) upto 3% of Installed Capacity or as may be specified by the Commission for the management of ramp up as per the requirement of the Grid.

14.4.4 During day ahead scheduling, SLDC shall provide target despatch schedule for such specified generator(s) after allowing for maintenance of spinning reserve margin upto 3% of Installed Capacity (or as specified by Commission).

Provided that distribution licensee having hydro generating stations (excluding small hydro power) under long term/medium term power purchase agreement/arrangement may offer to provide spinning reserve margin from such hydro generator in consultation with SLDC.

14.4.5 The distribution licensees may share the spinning reserve resources on mutually agreed terms.

14.4.6 SLDC shall prepare detailed procedure to operationalise provisions related to spinning reserve margin and submit the same to Commission upon stakeholder consultation within six months from the date of notification of applicability of MEGC.

5 Part C: Connection Code

This Code specifies the minimum technical and design criteria complied by the Transmission Licensee and User connected to or seeking connection with the InSTS. The IEGC 2010 Connection Code has introduced the procedure for connection to the ISTS, Connection Agreement Formats, Technical Requirements such as Reactive Power Compensation, Data and Communication Facilities, System Recording Instruments, Responsibilities for Safety, Cyber Security, etc. The same has been considered in the MEGC Regulations, 2020 with additional provisions for the Site Responsibility Schedule (SRS), Single Line Diagram (SLD), Site Common Drawing, Access at Control Site, etc.

In addition, the new provisions related to the Metering Arrangement, Connection Agreement, Equipment requirements to be installed by the State Entity/Users at the Connection Point when requesting for a new connection with the InSTS system are also specified in the MEGC Regulations.

5.1 Objective of the Connection Code

Objective of the Code includes:

a) To ensure safe reliable and integrated operation of the grid.

b) To treat all Users in a non-discriminatory manner.

c) Any new or modified connections, when established, shall neither suffer unacceptable effects due to its connectivity to the ISTS nor impose unacceptable effects on the system of any other connected User or STU.

d) By specifying optimum design and operational criteria, to assist Users in their requirement to comply with License obligations, to ensure that a system of acceptable quality is maintained.

e) Any User seeking a new connection to the grid is required to be aware, in advance, of the procedure for connectivity to the InSTS and the standards and conditions his system must meet for being integrated into the grid.

5.2 Applicability of Connection Code and Application for Connection Arrangement

Connection Code shall apply to all the Users requesting a new arrangement or modifying the existing arrangement of Transmission connection elements connected with the InSTS. The Commission has formulated a procedure to be followed by the Users while requesting the STU for connection with the InSTS and other necessary details that the Users need to provide with the application.

Application for connection to InSTS shall include the following details:

a) Report stating the purpose of the proposed connection and/or modification, Transmission Licensee to whose system connection is proposed, description of apparatus to be connected or modification of the apparatus already connected and beneficiaries of the proposed connection;

b) Construction schedule and target completion date;

c) Confirmation that the Transmission Licensee or the User shall abide by the provisions of these Regulations and all the relevant Regulations applicable.

5.3 Nodal Agency for Implementation of Connection Code

STU shall be the nodal agency for accepting the application and processing the application for InSTS connection.

5.4 Key Provisions of the Connection Code

MEGC Regulations, 2020 provides a detailed procedure for submission of the application along with the timelines and the provisions include rejection of the application by the STU to be submitted by the User. The STU shall ensure that all Users or prospective Users are treated equitably. Any new or modified connection, when established, shall not impose any adverse effect on InSTS nor shall a new or modified connection suffer adversely due to its connectivity to InSTS. The ownership and responsibility for all equipment are clearly specified in a Site Responsibility Schedule for each site where a connection is made.

The Commission has also specified provisions for Metering Arrangement requirements to be adopted by Users while requesting a connection with InSTS. Metering arrangement shall include metering type, standards, ownership, location, accuracy class, installation, operation, testing and maintenance, access, sealing, safety, meter reading and recording, meter failure or discrepancies, anti-tampering features, quality assurance, calibration and adoption of new technologies in respect of the meters for correct accounting, billing and audit of electricity. MERC Metering Code and Regulations issued by the Authority shall be binding on the Users connecting to the InSTS including the Users connected to 33 kilovolt (kV) bus at Extra High Voltage Substation (EHV SS) and distribution substation.

Connection Agreement to be executed by the User with STU shall include the details of connection, technical requirements, metering and commercial arrangements, details of any capital expenditure arising from necessary reinforcement or extension of the system, data communication etc. and demarcation of the same between the concerned parties. It will also include the responsibility of sharing of the charges incurred in necessary reinforcement or extension of the system, modalities for payment of connection charges, sharing of InSTS charges and the effective date for sharing of InSTS charges.

Users shall also include a single line diagram, substation equipment, protection system, communication arrangement, details of fault clearing time etc. in the Connection Agreement.

5.5 Monitoring and Reporting of variation in Grid Parameters

Transmission Licensees shall monitor and keep record of the month-wise Voltage Variation Index at Connection Points and submit report for the past six-monthly performance during next GCC meeting. GCC shall review and deliberate on the cause of the significant variations from the normal range and guide the remedial actions for the improvements. STU in consultation with GCC shall formulate detailed procedure for measurement, monitoring and reporting of the Voltage Variation Index at Connection Points covering intra-state transmission network. STU shall publish such report on its website from time to time.

6 Part D: Operating Code

This Code describes the conditions under which SLDC shall operate InSTS, and Users shall operate their facilities, insofar as necessary to maintain the security and quality of supply and safe operation of the InSTS under both normal and abnormal operating conditions.

6.1 Objective of the Operating Code

The primary objective of the Operating Code is the integrated operation of the InSTS to enhance the overall operational economy and reliability of the entire network. Users shall cooperate with each other and adopt good utility practice for satisfactory and reliable operation of the InSTS. All Users shall comply with this Operating Code for deriving maximum benefits from the integrated operation and for equitable sharing of responsibilities.

6.2 Applicability of the Operating Code

Operating Code is applicable to all Users connected with InSTS system. Provision in the draft regulations are as follows:

27.3. All licensees, generating company and any other Users connected to the InSTS shall comply with the directions issued by the SLDC to ensure integrated grid operation and for achieving the maximum economy and efficiency in the operation of the InSTS.

6.3 Nodal Agency for the Implementation of Provisions of the Operating Code

SLDC shall be the nodal agency for the implementation of the Operating Code in coordination with the OCC to be constituted under the aegis of GCC. Provision in the draft regulations are as follows:

28.2. SLDC, in coordination with Operation Coordination Committee, shall develop, document and maintain detailed operating procedures for managing the InSTS. These operating procedures shall include the following:

i. *Black start procedures;*

ii. *System restoration procedures for partial grid failure;*

iii. *Load curtailment procedures;*

iv. *Renewable Energy Curtailment Procedure*

v. *Islanding procedures; and*

vi. *Any other procedures considered appropriate by the SLDC.*

6.4 Operating Conditions:

The SLDC shall supervise the overall operation of the InSTS. SLDC, in coordination with Operation Coordination Committee, shall develop, document and maintain detailed operating procedures for managing the InSTS. These operating procedures shall include the following:

a) Black start procedures;

b) System restoration procedures for partial grid failure;

c) Load curtailment procedures;

d) Renewable energy curtailment procedures

e) Islanding procedures; and

f) Any other procedure considered appropriate by the SLDC.

Such procedures shall be developed in consultation with Users, licensees, renewable energy developers and WRLDC. Such procedures, after consulting in Grid Coordination Committee, shall be provided to all the Users. A copy of the same shall be uploaded on SLDC's website and submitted to the Commission for information.

The control rooms of the SLDC including Area/Sub-load Despatch Centres, Generating Stations, Substations of 132 kV and above and any other control centres of Transmission Licensees and Users shall be managed frequently by qualified and adequately trained personnel.

The control centres of distribution licensees (with recorded peak demand more than 100 MW) including Indian Railways shall carry out functions such as demand forecasting, load management, power management and real time revisions in schedule, demand curtailment etc. The control rooms shall have regular interaction with SLDC and act upon the instructions received from SLDC. The distribution licensees shall also develop online tracking and monitoring system for distributed generation including rooftop solar PV systems above 200kW within its license area for facilitating decisions of revision of drawal schedule during intra-day operation.

6.5 Key Provisions of the Operating Code:

a) Operation of Generators Connected to InSTS

b) Declaration of COD

c) Demonstration of Declared Capacity (DC) of Generating Units in the State

d) Principles of Merit Order Despatch for Operation of Inter State Generating Stations (InSGS) Connected to InSTS.

e) Guidelines for Technical Minimum Schedule for Operation of InSGS Connected to InSTS.

f) Guidelines for Zero Schedule for lnSGS Connected to InSTS

g) Guidelines for Instructing Reserve Shut Down (RSD) of Generating Unit by SLDC

h) Voltage Control and Reactive Power Management

6.6 Operation of Generators Connected to InSTS

The Report dated 17 September,2015 of the Committee constituted by CERC on Spinning Reserves proposes that, "no generating unit would be earmarked exclusively as reserves. Rather the margins available on part loaded generating units would be the reserve actuated through different means. (primary, secondary or tertiary). For this purpose, certain stipulations might be required in IEGC such as no power station could be allowed to schedule more than Installed Capacity less normative auxiliary consumption. This would facilitate margins for primary response. Further, the scheduling limit as a percentage of Declared Capability (DC), might need to be done for the power station so that margins are available for secondary and tertiary control.

The Commission also notes that, the Expert Group constituted by CERC and Technical Committee constituted by MoP recommends that RGMO may be phased out and replaced with 'speed control with droop'. Further, the dead band of +/-0.03 Hz (ripple factor in IEGC) may be gradually phased out as is being done in ERCOT Texas and Europe. This could be a voluntary approach initially. The new draft Grid Code prepared by the expert committee also proposes free governor mode of operation (FGMO) for all generating units in the country in order to arrest stead fall in the frequency in the event of a major grid disturbances.

Accordingly, considering the recommendations of the expert committee constituted by CERC for IEGC review related to FGMO, following thermal and hydro generating units shall be operated under free governor mode of operation (FGMO).

i. Coal/Lignite based thermal generating units of 200 MW and above;

ii. Open Cycle Gas Turbine/Combined Cycle generating stations having gas turbines of capacity more than 50 MW each;

iii. Hydro units of capacity more than 25 MW.

The generators presently operating under restricted governor mode of operation (RGMO) shall be if a generating unit cannot be operated under RGMO, then it shall be operated in FGMO Free Governor Mode Operation (FGMO) within one year from the date of notification of these regulations.

All coal/lignite based thermal generating units of 200 MW and above, open cycle gas turbine/combined cycle generating stations having gas turbines of more than 50 MW each and all hydro generating units of capacity more than 25 MW, operating at or up to 100% of their Maximum Continuous Rating, shall be capable of (shall not in any way be prevented of) instantaneously picking up to 105% and 110% of their maximum continuous rating respectively when frequency falls rapidly. After an increase in the generation as above, a generating unit may ramp back to the original level, at a rate of about 1% per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements shall be kept in operation (synchronized with the State Grid) only after obtaining the permission of SLDC.

For the purpose of ensuring primary response, SLDC shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the installed capacity of the generating station or unit (s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load and shall ensure that there is margin available for providing Governor action as a primary response. In case of gas/liquid fuel based units, a suitable adjustment in installed capacity should be made to the SLDC for scheduling in due consideration of prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit (s) thereof have been specified. However, scheduling of hydro stations shall not be reduced during high inflow period to avoid spillage.

All the generating units shall be capable of continuously supplying its normal rated active and/or reactive output at the rated system frequency and voltage, subject to the design limitations specified by the manufacturer. A generating unit shall be provided with an Automatic Voltage Regulator (AVR), protective devices and safety devices, as set out in Connection Agreement. If in case, any generating unit of over 50MW is required to be operated without its AVR in service, the SLDC shall be immediately intimated about the reason and duration and its permission be obtained.

Power system stabilizers in the AVR of generating units, wherever provided, shall be properly tuned by the respective generating unit owner based on the plan prepared by the STU for the purpose from time to time. The STU will be allowed to carry out checking of power system stabilizer and further tuning it, wherever considered necessary.

All generating stations connected to the Grid shall follow the instructions of SLDC for backing down/ramping down/shutting down the generating unit(s). SLDC shall provide a certificate for the period of the backing down/ramping down/shutting down for the purpose of computing the deemed generation if required.

SLDC shall make all efforts to evacuate solar, wind and solar-wind hybrid power available and treat as a must-run station. However, SLDC may instruct the solar/wind generator to back down generation on consideration of grid security is endangered and solar/wind generator shall comply with the same. For this, a data acquisition system facility shall be provided for the transfer of information to the SLDC.

a) SLDC may direct a wind farm to curtail its Volt-Ampere reactive (VAr) Drawal/Injection in case the security of the grid is endangered.

b) During wind generator start-up, the wind generator shall ensure that the Reactive Power Drawal (inrush currents in case of induction generators) shall not affect the grid performance.

Provision of protection and relay settings shall be co-ordinated periodically throughout the state grid as per the Protection Code and separately finalized by the Protection Committee as may be constituted under these Regulations. The Committee shall also prepare islanding schemes and ensure its implementation in accordance with the grid standards notified by the Authority. All Users shall ensure that the installation and operation of the protection system shall comply with the provisions of such grid standards notified by the Authority.

Users and Transmission Licensees shall provide automatic under-frequency and df/dt relay-based load curtailment/islanding schemes in their respective systems, wherever applicable, to arrest frequency decline that could result in a collapse/disintegration of the InSTS, as per the plan separately finalized by GCC and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency. The hydro generators having the capability to operate in pump mode are required to do so as per the instructions of SLDC.

6.7 Declaration of COD

As per Regulation 27 of MERC (Multi-Year Tariff) Regulations, 2019 the declared is defined as follows.

(27) ***"Declared Capacity"*** *means, in relation to a generating Station, the capability to deliver ex-bus electricity in MW declared by such generating Station in respect of any time-block of the day* ***as defined in the State Grid Code*** *or whole of the day, taking into account the availability of fuel and/or water, and subject to further qualification in the relevant Regulation*;

Further, the Central Commission has introduced the provisions for declaration of the COD of the InSGS, InSTS and assets thereof in IEGC vide the 4th Amendment in 2016. Similar provisions have been considered by the Commission in the Operating Code.

Date of commercial operation in case of a unit of thermal InSGS shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its Maximum Continuous Rating (MCR) or the Installed Capacity (IC) or Name Plate Rating on designated fuel through a successful trial run and after getting clearance from the SLDC, and in case of the generating station as a whole, the date of commercial operation of the last unit of the generating station.

The Code also specifies the need for Trial Operation of 72 hours by InSGS before declaring the COD.

Similar provisions are specified for COD declaration for any element of InSTS.

The certificate of COD shall be signed by the Director/Senior officer the generating company or transmission company as the case may be and a copy of the certificate shall be submitted to the SLDC, before the declaration of COD. The generating company or transmission company as the case may be shall submit approval of the Board of Directors to the certificates as required within three months of COD.

6.8 Declared Capacity (DC) Demonstration by InSGS

The Intra-State generators required to submit their availability of declare capacity on day ahead basis which it can be able to generate. The generators are expected to be available and generate to meet the demand of beneficiary with whom it has PPA or any contractual arrangement. To ensure the availability of generators as per the load requirement of beneficiary in advance, periodic conformity is necessary.

The Regulation 53 of the MERC MYT 2019 Regulations specifies the requirements of DC demonstration and provision for penalty for misdeclaration of declared capacity as below:

53.1 The Generating Company may be required to demonstrate the declared capacity of its Generating Station as and when asked by the MSLDC.

53.2 In the event of the Generating Company failing to demonstrate the declared capacity, the Annual Fixed Charges due to the Generating Company shall be reduced as a measure of penalty.

53.3 The quantum of penalty for the first misdeclaration for any duration/block in a day shall be the charges corresponding to two days fixed charges.

53.4 For the second misdeclaration, the penalty shall be equivalent to fixed charges for four days and for subsequent misdeclarations in the year, the penalty shall be multiplied in the geometrical progression.

Further, the Draft MEGC, 2020 specifies the details of the procedure, conditions, forms and formats for the Demonstration of DC of the Generating Units in the State. SLDC may ask the InSGS to demonstrate the DC or the Beneficiary may request SLDC to ask the InSGS to demonstrate the DC with whom it has the PPA. Following are the conditions in which MSLDC may ask the InSGS to demonstrate the DC.

31.1.1. In case the schedule by any Generator for a particular Unit during Peak Hours is lower than Off-Peak hours;

31.1.2. In case the schedule for a particular generating unit during the low demand period during the year is higher than the generation schedule during the high demand period during the year;

31.1.3. In case the variation in minimum and maximum generation schedule by any generator for a particular generating unit during various time-blocks of the Day is more than 30% of contracted capacity;

31.1.4 In case of the request by contracted distribution licensee;

31.1.5 At the discretion of the SLDC on random basis at any time which shall not be more than once every quarter.

(Explanation – For the purpose of these Regulations, the number of hours of "peak" and "off-peak" periods during a day shall be four and twenty respectively. The hours of peak and off-peak periods during a day shall be declared by the SLDC at least a week in advance. The high demand season (period of three months, consecutive or otherwise) and low demand season (period of remaining nine months, consecutive or otherwise) in the State shall be declared by the SLDC, at least six months in advance.

Provided that the SLDC, after duly considering the comments of the concerned stakeholders, shall declare peak hours and high demand season in such a way as to coincide with the peak hours and high demand season of the State).

The detailed procedure along with reporting format to be provided by SLDC after the demonstration of DC is enclosed as Annexure-3 with the Regulations. The flow of activities for DC Demonstration shall be as shown in the table below.

Table 4: Flow of Activities for DC Demonstration

Time Block	Time	Particulars
1st Block	12:00 to 12:15	• Application for DC Demonstration from Nodal Officer of Distribution Licensee to Nodal Officer of SLDC. • No request of Generator for change of DC shall be entertained till DC demonstration procedure is completed.
2nd and 3rd Time Block	12:15 to 12:45	• Verification and appropriate action such as alternate generation peaking etc, maintaining Grid discipline and DC demonstration implementation.
4th Time Block	12:45 to 13:00	• Convey instructions and required injection based on the application of the Distribution Licensee/SLDC to the concerned Generator for demonstration by SLDC.
5th Time Block	13:00 to 13:15	• Reserved for the Generator for taking necessary actions for ramping-up of the Generation.
6th to nth Time Block	13:15 onwards	• Commencement of the physical ramping-up of Generation for attaining DC.

Time Block	Time	Particulars
		• From 6^{th} time block, actual increase in the Generation shall commence n^{th} time block as per the ramping rate.
n^{th} to $n+12^{th}$ Time Block	---	• The DC demonstration period, i.e., the12^{th} time block may vary depending on system condition.
Concerned Generator shall maintain operating log-book with details of activities carried out during DC demonstration.		

If generator unit is unable to ramp up the under circumstances specified in the Regulations, such instance will be considered as misdeclaration by the generator and the penalty as per the provisions of MYT Regulations shall be made applicable.

For generating units whose Tariff is being determined by the Commission under Section 62 of the EA 2003, the penalty shall be as per the MYT Regulations and for the Generating Units having PPAs entered into under Section 63, the penalty shall be as per the provisions of PPA or as per following conditions, whichever is higher :

i. In the event of the Generating Company failing to demonstrate the declared capacity, the Annual Fixed Charges due to Generating Company shall be reduced as measure of penalty

ii. 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

iii. For the second mis-declaration, the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations in the year, the penalty shall be multiplied in the geometrical progression.

The generator which fails to demonstrate the DC shall require to re-demonstrate the DC for which it had failed to demonstrate with prior request to SLDC and concerned beneficiary as per the detailed procedure. Such generator shall not be allowed to request for re-demonstration of DC on the same day.

Further, the SLDC shall cap the DC of such generator to the actual generation demonstrated during test for the remaining time-blocks of that day or till such time the generator re-demonstrates the higher DC than the actual generation demonstrated during testing. The costs associated with re-demonstration of DC shall be borne by such Generator.

SLDC shall prepare the report of such instances of misdeclaration in the format enclosed as Annexure-6 and publish the report on its website. MSLDC shall send the report to the concerned Distribution Licensee having PPA with the Generating Unit on a monthly basis, by 5th of every month.

6.9 Merit Order Despatch (MOD) Principles

The Commission had issued the Guidelines for the operation of MOD under ABT Order on 8 March,2019 in line with the principles set out in ABT Order. These Guidelines were to be effective for implementation from the month of April, 2019. However, these guidelines were challenged before Hon'ble Appellate Tribunal for Electricity (APTEL). Following main issues were contested in the Appeal filed before Hon'ble Tribunal:

A. Discriminatory treatment qua computation of variable charge for preparing MoD Stack.
B. MoD Guidelines makes inroad to the Change of Law provisions under Section 63 PPA.
C. Preferential treatment to the Open Access Transactions.
D. Issues re. implementation of Technical Minimum.

The Hon'ble Tribunal has allowed the prayer of Appellant and stayed the implementation of provisions of the MoD guidelines.

The Commission has filed its submission before Hon'ble Tribunal on 25 May,2019 as below:

1. *Considering the issues raised during arguments before Hon'ble Tribunal, the Commission is in a process of suitably amending and/or revising 2.5(b) and 2.5(c) of the MoD Guidelines regarding the change-in-law impact.*
2. *In the interregnum, the Commission has decided to seek permission of this Hon'ble Tribunal to implement the impugned MoD Guidelines subject to modification of 2.5(b) &2.5(c) to the effect that change-in-law impact will be taken into account for preparation of the MoD stack only after approval of the Commission of such impact as notified by the generator to the distribution licensee.*
3. *As regards the issue of reduction of the Technical Minimum and the compensation in lieu thereof, the Commission submits that it has initiated a process of devising the compensation mechanism in line with the compensation mechanism introduced by CERC vide its Order dated 5 May,2017.*

Meanwhile the Commission has notified the DSM Regulations,2019 on 1st March,2019. The Commission is expected to stipulate principles for merit order operation in line with provisions specified in the MERC DSM Regulations,2019. In pursuance of the MERC DSM Regulations, 2019, the Commission has approved Scheduling and Despatch Code on 11 November 2019 upon following due regulatory and stakeholder consultation process.

Further the Commission is also reviewing its State Grid Code,2006 under present regulatory process, wherein some of the aspects of Operation Code of MEGC also deal with merit order operation of intra-state entities. The Commission finds it appropriate to provide modified provisions of clause 2.5(b) &2.5(c) of MoD Guidelines to the effect that change-in-law impact. The Commission has also specified the compensation mechanism for reduction of the Technical Minimum in line with the compensation mechanism introduced by CERC in para 6.10 of the explanatory memorandum.

Accordingly, the Draft MEGC considers all the issues contested before the Hon'ble Tribunal in the present revision of Draft State Grid Code,2020 and the Draft State Grid Code,2020 shall be finalized upon due public consultation process.

Proposal under MEGC 2020

In view of the above, following provisions are proposed in the Draft MEGC:

32.1 SLDC is responsible for coordinating the scheduling of Buyers and Sellers within its control area. SLDC shall also be responsible for Preparation of Merit Order (MOD) Stack for Day Ahead scheduling process for each month considering the principles specified in the MERC DSM Regulations and the Principle specified in this MEGC as amended from time to time.

32.2 SLDC shall prepare Buyer wise MOD Stack for day-ahead scheduling process and centralised MOD Stack for intra-day operation considering the principles specified in the MERC DSM Regulations and Scheduling and Despatch Code under the SGC by the Commission.

32.3 SLDC shall prepare separate MOD Stack for each Buyer considering the contracts of respective Buyer and least cost principles as specified in the MOD Principles of SGC.

32.4 SLDC shall also prepare Centralised MOD Stack of the generators for real-time operation, in case the grid parameters including frequency, voltage, transmission line loading, substation loading conditions or State volume limits (presently +/-250 MW) deviate beyond permissible operating range as specified in the Scheduling and Despatch Code.

32.5 For preparation of MoD Stack, seller whose tariff is determined by the Commission or seller whose tariff is adopted by the Commission shall project the unit wise variable charge for the next month for which MoD is to be prepared considering all the possible charges including impact of change in law and submit to the buyer by 11^{th} day of every month.

32.6 The seller shall also submit to the buyer, all the computations and supporting documents considered for projection of variable charge for the next month.

Provided that, the seller shall consider the variable charge approved/adopted by the Commission and FSA billed during latest month and impact of all the change in laws already approved by the Commission and projected impact on the variable charge on account of change in law by various authorities.

32.7 The buyer shall verify the variable charge submitted by seller and submit to the SLDC for preparation of MoD stack by 14th day of every month with intimation to seller with whom it has PPA.

32.8 SLDC shall prepare the MoD Stack on the 15th day of every month, which would be effective from the 16th day of the month till the 15th day of the subsequent month unless revised by SLDC. SLDC shall upload the monthly MoD Stack on its website as per the format provided in the Scheduling and Despatch Code by 15:00 hours on the 15th day of every month.

32.9 MoD Stack uploaded on the 15th of the month may be subsequently revised by SLDC in the following circumstances:

a) *Commencement of supply of power by a Generating Unit under a new arrangement/agreement,*
b) *Revision of Variable Charges for preparing the MOD Stack due to Tariff Order issued by this Commission for State Generating Stations or the CERC for Central Generating Stations,*
c) *Impact of Change in Law in the PPAs as notified by the Distribution Licensee.*

32.10 The Commission shall scrutinise and ascertain the variations, if any, from the basis of projection of variable charge during prudence check at the time of truing up of Generating Stations whose tariff is determined by the Commission and in case of claims for revision in Variable Charge on account change in law in case of generating stations whose tariff is adopted by the Commission.

Provided that, during prudence check if the Commission observes that, the seller has not considered the impact of change in law in existence at the time of projection of variable charge for MoD purpose, the Commission shall disallow the same.

Provided further that at the time of true-up of power purchase cost of Buyers, the Commission shall consider the adherence to MoD principles followed by Buyers and due diligence exercised by the Buyers on claims of projected variable charges as estimated by Sellers to ensure overall efficacy of the power procurement by Buyers.

32.11 For Central Section Generating Stations (CSGS), the Variable Charge for MOD purposes shall be the landed variable cost at the State periphery for the immediately preceding month, including the injection losses, drawal losses of CTU and other such charges like Electricity Duty Cess of exporting State.

32.12 The Seller shall consider impact of Change in Law in the Variable Charge that it intimates to Buyer and Buyer to SLDC for preparation of the MOD Stack. However, the payments for such Change in Law claims will be made by the Buyer to Seller after the approval of the Commission in accordance with the provisions of the MYT Regulations or provisions of PPA.

32.13 For Intra-State Open Access transactions having single part tariff, total tariff shall be considered as Variable Charge for MOD purpose.

32.14 The Variable Charges for MOD purposes shall be provided up to four decimal places.

6.10 Mechanism for Compensation Due to Part Load Operation of Units of Intra-State Generators connected to InSTS in Maharashtra State

The Commission in MERC F&S Regulations, 2018 has specified that, the

*3.3. **The SLDC shall make use of the flexibility provided by Conventional Generating Units** and the capacity of inter-Grid tie-lines to accommodate Wind and Solar energy generation to the largest extent possible subject to Grid security.*

The Commission notes that, the Central Commission vide 4th Amendment to the IEGC is specified as below:

6.3B – Technical Minimum Schedule for operation of Central Generating Stations and Inter-State Generating Stations

*1. The technical minimum for operation in respect of a unit or units of a Central Generating Station of inter-State Generating Station shall be **55% of MCR loading** or installed capacity of the unit of at generating station.*

The Central Commission vide notifying the 4th Amendment to IEGC has referred the provisions of CEA's Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 as below:

"The control range for coal fired unties is generally taken as 50% to 100% MCR and the rated steam temperature can be maintained in this range. However, the units can operate at any lower load without any limits; and minimum load without oil support is taken as about 30% MCR and operation below this limit needs oil support. The CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 prescribe a control load of 50% MCR. The operating capability generally specified in the technical specifications also stipulate continuous operation without oil support above 30% MCR load and control load range of 50% to 100% TMCR.

Further, provisions of CEA's Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 specifies as below:

(11) Pulverized fuel consumption based on steam generator shall not require oil support above 40%unit load. However, FBC based steam-generator shall be designed such that oil support is not needed beyond 25% load.

The IEGC Amendment Regulations inter-alia contained provisions relating to

a) Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Technical Minimum Schedule;

b) Mechanism for Compensation for Degradation of Heat Rate, Aux Consumption and Secondary Fuel Oil Consumption, due to part load operation and multiple start/stop of units.

Further, the Commission in its MoD guidelines dated 8 March,2019 had specified as below:

8.1 The Technical Minimum for operation in respect of a coal fired/gas fired/multi fuel based thermal generating unit connected to the STU shall be 55%of its installed capacity.

8.2 The Commission shall devise an appropriate methodology, in the due course of time, for compensating such thermal generating stations for the loss of operating parameters on account of revised technical minimum level vis-à-vis existing technical minimum level.

Further, the Commission in its MYT Regulations, 2019 is specified as below:

46.10 In case a Generating Station or Unit is directed by MSLDC to operate below normative loading but at or above technical minimum schedule on account of grid security or due to the lower schedule given by the Beneficiaries, ***increase in Gross Station Heat Rate may be considered by the Commission on case to case basis at time of truing up, subject to prudence check.***

Accordingly, the provisions in Draft MEGC,2020 related to technical minimum operation of TPS are as below:

Proposal under MEGC 2020

33.1. The technical minimum for operation in respect of a unit or units of Intra-State Generating Stations shall be 55% of MCR loading or installed capacity of the unit of generating station.

The Commission has specified appropriate provision in the Draft MEGC Regulations, 2019 regarding the mechanism for compensation due to part load operation of units of InSGS connected to InSTS in the State. The proposed mechanism for compensation considers the Degradation of Heat Rate, change in Aux Consumption and Secondary Fuel Oil Consumption due to part load operation and multiple start/stop of units of InSGS as below:

33.3. InSGS, who will be directed by SLDC to operate below normative plant availability factor but at or above technical minimum, shall be compensated depending on the Average Unit Loading (AUL) duly taking into account the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis duly supported by relevant data verified by SLDC.

Provided that no compensation for SHR degradation or increase in AEC shall be payable if the AUL for the generating station for the computation period works out to be more than or equal to 70%.

The Detailed Procedure for computation of additional charges payable to the Generator is provided as Annexure-4 in the draft MEGC Regulation.

The Draft Regulation proposes that the Generator will work out additional compensation based on the procedure given in the Regulations on a monthly basis and submit to the beneficiary for acceptance and payment with an intimation to MSLDC. MSLDC shall provide the data of implemented schedule to the generator and beneficiary.

6.11 Zero Schedule for InSGS Connected to InSTS

The Commission has introduced the concept of "ZERO SCHEDULING" in the Draft MEGC Regulations, 2020 wherein, the Distribution Licensees need to optimize their cost of power procurement considering the contracted sources for the period of anticipated surplus.

The decision of Zero Schedule to the Generator shall be at the discretion of the Distribution Licensee with whom it has a PPA. The Draft Regulations provide guiding principles for the decision of Zero Scheduling by the Distribution Licensee and roles and responsibilities of the MSLDC while accepting the request of Zero Scheduling by the Distribution Licensee. The Provisions of the Draft Regulations are as below:

34 Guidelines for 'Zero Schedule' for InSGS connected to InSTS

34.1. In case of anticipated generation availability in surplus of anticipated demand, the Distribution Licensees need to optimise their cost of power procurement considering the contracted sources for the period of anticipated surplus.

34.2. The distribution licensee shall ensure that, the there shall not be any adverse impact on its power procurement cost on account of zero scheduling of contracted generator.

Provided that, the Commission shall verify the decisions of zero scheduling of unit vis-à-vis power procurement cost from alternate sources during trueing up of distribution licensee.

34.2. If the anticipated generation availability is more than the anticipated demand, the Distribution Licensee in consultation with SLDC may consider giving Zero Schedule to some of its contracted sources for the period during which the demand is expected to be lower than the total contracted sources availability put together.

34.3. SLDC shall provide its concurrence to the proposed "Zero Schedule" by Distribution Licensee taking into account the demand supply position and transmission constraints.

34.4. If grid constraints prevent the Zero Scheduling of the Unit with the highest Variable Charge in the MOD Stack, the Unit with the next highest Variable Charge needs to be considered. However, SLDC shall publish the details of such grid constraints on its website, along with the period for which it is likely to persist.

34.5. The Distribution Licensee shall give the Generator 24 hours prior notice of the Zero Scheduling to enable it to take steps for smooth removal of the Unit from the Grid.

34.6. In case a particular Unit is, in fact, required to be scheduled during the pre-declared Zero Scheduling period, the Distribution Licensee shall intimate the Generator at least 72 hours in advance for the Unit(s) to come on bar in cold start.

34.7. Zero Scheduling shall be carried out by Distribution Licensee keeping in consideration its roles and obligations under the corresponding PPAs.

34.8. Any additional cost implication in Variable Charges (by means of inferior norms of operation or minimum fuel off-take conditions) that arises on account of Zero Scheduling will not be allowed as pass through while truing up the power procurement cost.

34.9. Any additional cost implication in Variable Charges (by means of inferior norms of operation or minimum fuel off-take conditions) if any arises that arises on account of Zero Scheduling shall not be payable to the generator. will not be allowed while truing up the power procurement cost.

6.12 Reserve Shut Down on Scheduling Below Technical Minimum Schedule

The Central Commission vide 4th Amendment to the IEGC, 2010 specified the detailed operating procedure for backing down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Technical Minimum Schedule. Similar provisions for InSGS shall help the Distribution Licensees to minimize their Power Purchase cost. Accordingly, the Commission has proposed similar provision in the draft MEGC Regulations, 2019 as below:

35 Guidelines for instructing Reserve Shut Down (RSD) of Generating Unit By SLDC

35.1. A Reserve Margin equivalent to the contracted capacity of the largest Unit of the Power Station, contracted by the Distribution Licensee needs to be maintained.

35.2. The RSD should be implemented for the capacity available in excess of the largest Unit contracted by the Distribution Licensee.

35.3. The RSD should be applied to Units with higher Variable Charges in the MOD Stack, subject to grid conditions permitting the same.

35.4. SLDC shall upload details of RSD of the previous month in the format at Annexure-5 on its website by the 3rd of every month.

6.13 Voltage Control and Reactive Power Management

Reactive Power management is vital for maintaining voltage within the permissible band. The strategies include switching shunt capacitors, switching shunt reactors, Inter Connecting Transformer (ICT) tap coordination, reactive power generation/absorption by generators, operation of hydro units in synchronous condenser mode as well as switching of lightly loaded and redundant Extra High Voltage (EHV) /Ultra High Voltage (UHV) transmission lines.

Reactive Power compensation and/or other facilities shall be provided by the STU/Users, as far as possible, in the areas prone to low or high voltage systems close to the load points thereby avoiding the need for exchange of Reactive Power to/from the InSTS and to continuously maintain the InSTS voltage within the specified range.

Line Reactors may be provided to control temporary overvoltage within the limits as set out in the Connection Agreements. The additional reactive compensation to be provided by the User shall be indicated by the STU in the Connection Agreement for implementation.

Users shall endeavor to minimize the Reactive Power Drawal at the interchange point when the voltage is below 97% of rated voltage and shall not inject Reactive Power when the voltage is above 103% of rated voltage. Interconnecting transformer taps at the respective drawal points may be changed to control the Reactive Power interchange as per the User's request to the SLDC, but only at reasonable intervals.

6.13.1 Provision of the CEA Regulations, 2013 "Manual on Transmission Planning Criteria" for Reactive Power Management

10.2.1 Reactive power plays an important role in EHV transmission system planning and hence forecast of reactive power demand on an area-wise or substation-wise basis is as important as active power forecast. This forecast would obviously require adequate data on the reactive power demands at different substations as well as the projected plans for reactive power compensation.

10.2.2 For developing an optimal ISTS, the STUs must clearly spell out the substation-wise maximum and minimum demand in MW and MVAr on a seasonal basis. In the absence of such data, the load power factor at 220 kV and 132 kV voltage levels may be taken as 0.95 lag during peak load condition and 0.98 lag during light load condition. The STUs shall provide adequate reactive compensation to bring power factor as close to unity at 132 kV and 220 kV voltage levels.

14.1 Requirement of reactive power compensation like shunt capacitors, shunt reactors (bus reactors or line reactors), static VAr compensators, fixed series capacitor, variable series capacitor (thyristor controlled) or other FACTS devices shall be assessed through appropriate studies.

14.2.1 Reactive Compensation shall be provided as far as possible in the low voltage systems with a view to meet the reactive power requirements of load close to the load points, thereby avoiding the need for VAr transfer from high voltage system to the low voltage system. In the cases where network below 132kV/220 kV voltage level is not represented in the system planning studies, the shunt capacitors required for meeting the reactive power requirements of loads shall be provided at the 132kV/220kV buses for simulation purpose.

14.2.2 It shall be the responsibility of the respective utility to bring the load power factor as close to unity as possible by providing shunt capacitors at appropriate places in their system. Reactive power flow through 400/220kV or 400/132kV or 220/132(or 66) kV ICTs, shall be minimal. Wherever voltage on HV side of such an ICT is less than 0.975 pu no reactive power shall flow down through the ICT.

Similarly, wherever voltage on HV side of the ICT is more than 1.025 pu no reactive power shall flow up through the ICT. These criteria shall apply under the 'N-0'conditions.

14.3.1 Switchable bus reactors shall be provided at EHV substations for controlling voltages within the limits without resorting to switching-off of lines. The bus reactors may also be provided at generation switchyards to supplement the reactive capability of generators. The size of reactors should be such that under steady state condition, switching on and off of the reactors shall not cause a voltage change exceeding 5%.

16.4 The wind and solar farms shall maintain a power factor of 0.98 (absorbing) at their grid interconnection point for all dispatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies.

Switching in/out of 400 kV bus and line reactors throughout the Grid shall be carried out as per the instructions of MSLDC. Tap changing on 400/220 kV interconnecting transformers shall be done as per the instructions of SLDC only. The Users already connected to the Grid shall also provide additional reactive compensation as per the quantum and time decided by the SLDC.

6.13.2 Transformer TAP Changing Criteria

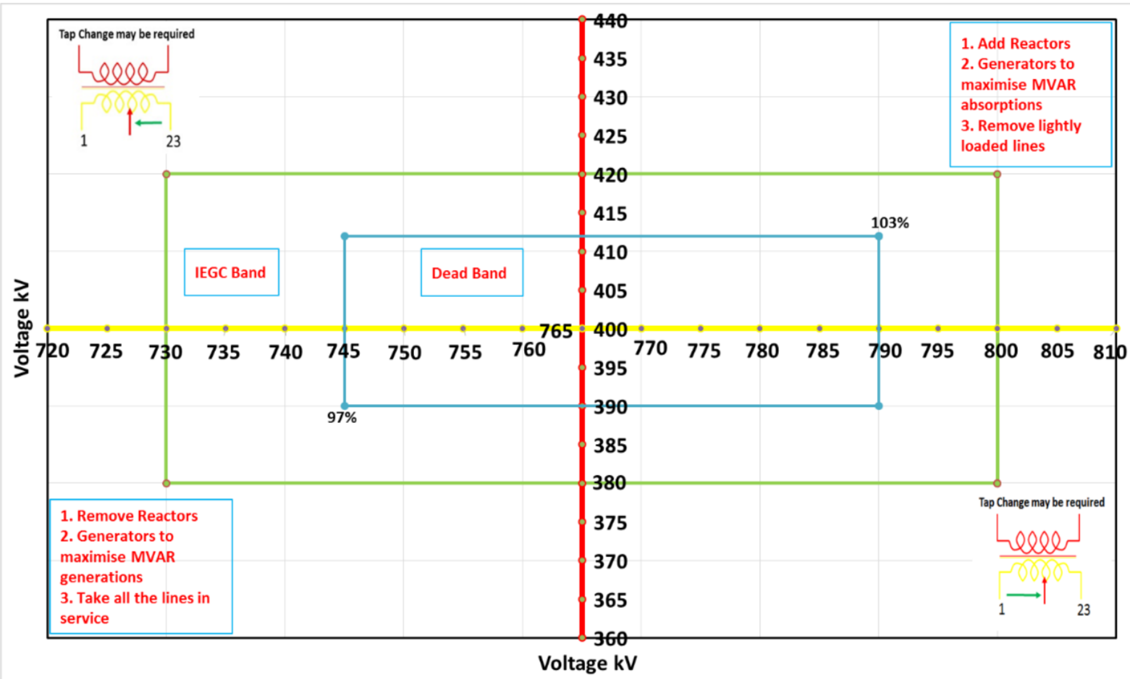

Figure 1: 765/400 kV Transformers

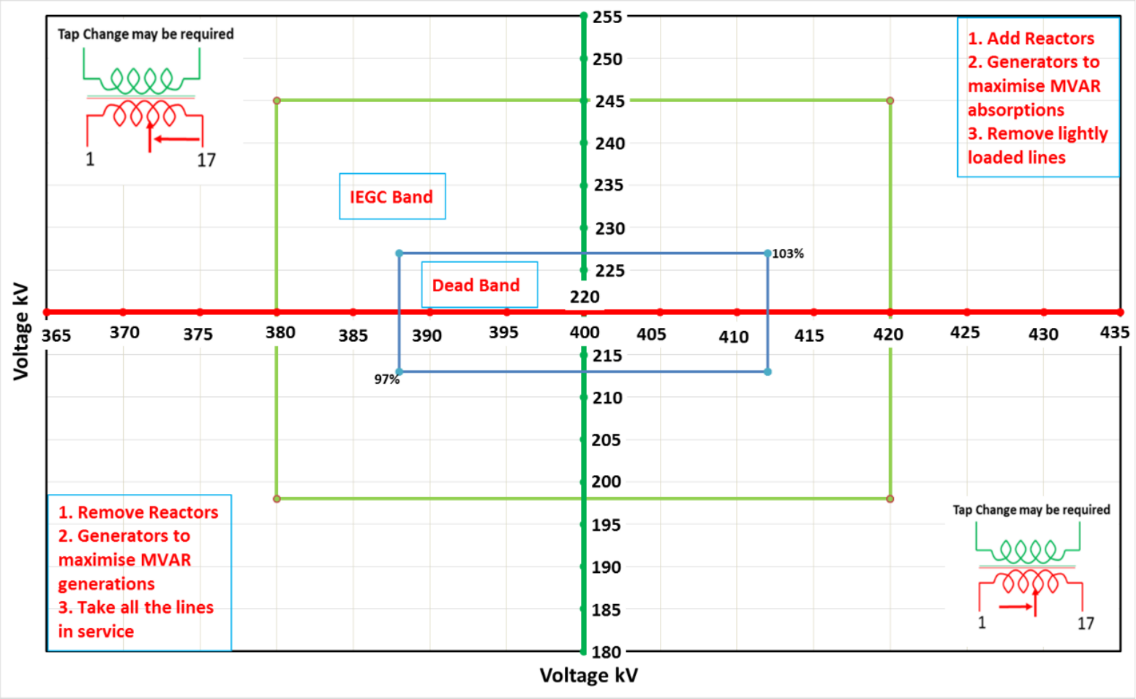

Figure 2: 400/220 kV Transformers

The generating station shall change generator transformer taps and generate/absorb Reactive Power as per the instructions of SLDC within the capability limits of the respective generating units, i.e., without sacrificing the required active generation. Payments shall be allowed to be paid to the generating stations for such VAr generation/ absorption at the generating stations as per the detailed procedure enclosed as Annexure-7 of these Regulations.

SLDC may direct the User to curtail its VAr Drawal/Injection in case the security of the Grid or safety of any equipment is endangered.

As per Regulation 70 of MERC (Multi-Year Tariff) Regulations, 2019, the Generating Station shall inject/absorb the Reactive Energy into the Grid based on the machine capability as per the directions of MSLDC. Reactive Energy exchange, only if made as per the directions of MSLDC, for the applicable duration (injection or absorption) shall be compensated/levied by the MSLDC to the Generating Station, as specified in the State Grid Code.

The Transmission System Users shall be subjected to Incentive/Disincentive to be compensated/levied by the MSLDC for maintaining the reactive energy balance in the transmission system, as specified in the State Grid Code.

Accordingly, the Commission has specified the mechanism for Accounting and Settlement of Reactive Energy Charges in the State under this Regulation.

6.13.3 Applicability of the Mechanism

a) The mechanism shall be applicable to all the Transmission System Users'(TSUs') and a Generator (including wind and solar generators) or a group of Generators connected through Pooling Substation to InSTS in the State.

b) The mechanism shall be implemented in the State after installation of Special Energy Meters (SEMs) at all G<>T & T<>D interface points in the State and from the date to be notified by the Commission.

c) Any bills raised on account of Reactive Energy Charges prior to the date of notification of the said mechanism by the Commission shall be settled as per the separate directives issued by the Commission.

6.13.4 General Principle

a) Reactive Power compensation and/or other facilities shall be provided by the Users, as far as possible, in the low voltage systems close to the load points thereby avoiding the need for exchange of Reactive Power to/from the InSTS and to maintain the InSTS voltage within the specified range.

b) Suitable Line Reactors shall be provided to control temporary overvoltage within the limits as per the system study carried out by the STU.

c) Additional reactive compensation shall be provided by the TSUs as indicated by the STU.

d) Switching in/out of 765/400 kV bus and line reactors throughout the InSTS shall be carried out as per the instructions of MSLDC. Tap changing of all 765/400/220 kV ICTs shall also be done as per the instructions of MSLDC.

6.13.5 Methodology for Accounting and Settlement

a) **To discourage VAr Drawal/Injection by the TSUs and Generating Unit, VAr exchanges with InSTS shall be priced as follows:**

(i) The TSUs and Generating Unit shall **pay into the Pool for any VAr Drawal** when the voltage at interface metering point is **below 97% of the bus voltage at which the TSU and Generating Unit is connected**.

(ii) The TSUs and Generating Unit shall **get paid from the Pool for any VAr injection** when the voltage at a metering point is **below 97% of the bus voltage at which the TSU and Generating Unit is connected**.

(iii) The TSUs and Generating Unit shall **get paid from the Pool for any VAr Drawal** when the voltage at a metering point is **above 103% of the bus voltage at which the TSU and Generating Unit is connected**.

(iv) The TSUs and Generating Unit **pays into the Pool for any VAr Injection** when the voltage at a metering point is **above 103% of the bus voltage at which the TSU and Generating Unit is connected**.

Provided that there shall be no charge/payment for VAr Drawal/Return by a TSU except the Generating Unit in its own line radiating from a Generating Station.

Provided further that reactive energy exchange, only if made as per the directions of SLDC, for applicable duration (injection or absorption) shall be compensated/levied by SLDC to the generating station, as per following conditions:

Table 5: Methodology of Reactive Power Compensation

Voltage/Condition of TSU and Generating Unit	VAr Drawal from InSTS	VAr Injection into InSTS
V_{meter} < 97% of V_{bus}	Pay into the Pool	Get paid from the Pool
97% < V_{meter} < 103%	No payment	No payment
V_{meter} > 103% of V_{bus}	Get paid from the Pool	Pay into the Pool

b) The charge for kVArh (injection / drawal) to be levied shall be 13.00 paise/kVArh or such other rate as may be stipulated by Commission from the date of applicability of implementation of reactive power compensation mechanism in the state and the same shall be escalated by 0.50 paise/kVArh annually in subsequent years unless otherwise revised by the Commission.

c) Notwithstanding the above, SLDC may direct TSUs' and Generating Station to curtail its VAr Drawal/Injection in case the security of the grid or safety of any equipment is endangered.

d) The Generating Stations connected to InSTS shall generate/absorb reactive power as per the system conditions without any specific instructions of MSLDC, within the Capability Curve limits of the respecting Generating Units, that is without sacrificing Active Generation required at that time.

e) MSLDC shall monitor the Injection/Absorption of Reactive Energy by the Generators during real-time and issue instructions during voltages beyond 97% and 103% only to specific default generators.

f) The operation of any hydro generation in condenser mode is a specific function depending on the system requirements. Hence, the operation of any hydro generation in condenser mode shall be as per the instructions of MSLDC only. MSLDC shall maintain records for such operations.

g) During major grid disturbances, the bus voltages may deviate beyond set points. In such case, MSLDC shall declare details of such incidence along with a period, which may be excluded from accounting; however, it shall be the responsibility of the TSUs' and the Generating Stations located in the affected area, to provide necessary active and reactive support as per the instructions of MSLDC. MSLDC shall maintain records of such instances and instructions.

h) In case TSUs and/or Generators have been levied penalty for four consecutive weeks, then an additional charge of 20% of total weekly Reactive Charges arrived at 4th week, shall be levied to the concerned TSU or Generator.

6.13.6 Accounting and Settlement of Reactive Energy

a) It shall be the responsibility of STU to install SEMs at all G<>T and T<>D interface points in the InSTS along with Automatic Meter Reading (AMR) facility.

b) It shall be the responsibility of STU/Transmission Licensees to provide meter data of Reactive Energy recorded for a week to MSLDC within 10 days for accounting and computation.

c) It is the responsibility of MSLDC to maintain State Reactive Energy Pool Account.

d) MSLDC shall prepare and issue provisional weekly Statement of VAr charges for all the TSUs and Generating Stations in the State who have net Reactive Energy Drawal/Injection under low/high voltage conditions within 10 days from the receipt of AMR from all the TSUs'.

The detailed procedure for accounting and settlement of intra-state Reactive Energy charges have been specified in Annexure-7 of the draft MEGC Regulations 2019.

6.14 Demand Estimation

The Commission in its explanatory memorandum to MERC DSM Regulations, 2019 has emphasized the responsibility of Demand Forecast on Distribution Licensees/Buyers. Accurate Demand Forecasting by Distribution Licensees/Buyers will help MSLDC to manage the availability of the transmission system. The proposed provisions in the Draft MSGC Regulations, 2020 are as below:

37 Demand Estimation

37.2. All Buyers shall be responsible for the estimation of their own demand. Buyers shall submit their demand estimation to SLDC for demand estimate of the State. All Buyers shall also maintain historical data for demand estimate.

Provided that SLDC shall refer to the demand estimate considered by STU while developing the transmission system Plan under Regulation 12.1 of these Regulations.

37.3. Each Buyer shall develop methodology for daily/weekly/monthly/yearly demand estimation in MW and MWh for operational analysis purposes as well resource adequacy. All Buyers shall also maintain historical database for demand estimation.

37.4. Each Buyer shall utilize state of the art tools, weather data, historical data and any other data for getting effective demand estimate for operational use. Each Buyer shall compare the actual demand with forecast demand and compare the forecasting error for improvement. The Buyers shall maintain the data of forecast error for daily/day-ahead/weekly/monthly and yearly basis on their website.

37.7. In order to facilitate estimation of Total Transfer Capability /Available Transfer Capability (ATC) on three month ahead basis, the SLDC shall furnish monthly estimated demand and availability data to RLDCs and RPC for better operation planning.

37.8. The SLDC shall take into account the Wind Energy/ Solar Energy forecasting to meet the active and reactive power requirement.

6.15 Demand Curtailment

The Commission has proposed the provision of Demand Curtailment in line with the Demand disconnection provisions specified in IEGC 2010. Buyers including Distribution Licensees and Users shall endeavour to restrict their actual drawal from InSTS of its control area within their respective drawal schedules. The Buyers are expected to install automatic demand management scheme for their load. If such a scheme is not available, the manual load curtailment shall be done to ensure that there is no overdrawal.

The provision mandates SLDC to consult with the Licensees and prepare automatic demand management schemes relating to InSTS. The provision in the draft regulations are as follows:

38.3.5. The interruptible loads for demand management shall be arranged in four (4) groups of loads such as:

(a) Scheduled load curtailment,

(b) Unscheduled/emergency load curtailment,

(c) Loads to be shed through under frequency relays or df/dt relays and

(d) Loads to be shed under any System Protection Scheme such as islanding, to maintain the frequency within the permissible limits and network security:

6.16 Outage Planning

The Commission has proposed Generation, Transmission and Distribution System Outage Planning in the draft MEGC Regulations, 2019 in line with the provision of the IEGC 2010.

41.3.3. All Users and STU shall follow annual outage plans published by SLDC. If any deviation is required the same shall be with prior permission of SLDC. The outage planning of run-of-the-river hydro plant, wind and solar power plant and its associated evacuation network shall be planned to extract maximum power from these renewable sources of energy.

41.3.4. Transmission Outage Planning shall be harmonized with Generation Outage Planning and Distribution System Outage Planning shall be harmonized with Generation and Transmission Outage Planning.

41.3.9. SLDC shall prepare & submit to WRPC its outage plan in writing for the next financial year by 30th November for each year. These shall contain identification of each Generating Unit/Transmission Line/Interconnecting Transformer for which outage is being planned, reasons for outage, the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date. SLDC shall submit LGBR for peak as well as off-peak scenario by 31st October for the next financial year to WRPC. The annual plans for managing deficits/surpluses shall be clearly indicated in the LGBR.

6.17 Congestion Management

In line with the provisions of the Central Commission's CERC (Measures to Relieve Congestion in Real Time Operation) Regulations, 2009, the Commission introduced similar provision for Congestion Management which shall be reviewed by the GCC and Congestion Charges, if any, shall be approved by the Commission.

43 Congestion Management

43.1. STU in consultation with SLDC shall develop procedure for relieving congestion in the InSTS within period of 6 (six) months from the notification of this Regulations:

Provided that, till the time such procedures are developed, Congestion Management in a real time system shall be dealt with as per Central Commission's relevant Regulations *as amended from time to time:*

Provided further that such procedure shall be reviewed by GCC and shall be provided to all the Users and shall be kept on the website of SLDC as well as STU.

Provided further that congestion charges, shall be applicable if determined by the Commission from time to time.

7 Part E: Scheduling and Despatch (S&D) Code

The Commission has notified MERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2019 on 1 March 2019. As per the provisions of the MERC DSM Regulations, the SLDC prepared draft S&D Code and draft Deviation Settlement and Energy Accounting Procedure and published for stakeholder's comments on its website on 9 May 2019. SLDC received the comments/suggestions from the stakeholders on the draft S&D Code and DSM Procedure. Considering the Stakeholder comments and suggestions, SLDC revised the Draft S&D Code and DSM Procedure appropriately and submitted to the Commission for approval on 20 August 2019.

The Commission reviewed the draft S&D Code and DSM Procedure submitted by the SLDC and approved the draft S&D Code and DSM Procedure on 11 November 2019 and directed to publish the approved copies on SLDC's website. This approved S&D Code shall form Part E of these Regulations and shall be read with MERC State Grid Code as may be required.

8 Part F: Communication Code

This Code deals with the provisions related to the Communication requirements of the Users connected with the InSTS. It also lists out the User's roles and responsibilities in communicating the information, communication boundary, testing and auditing of communication equipment, fault reporting and communication system availability. The proposed provisions of the draft MEGC Regulations, 2020 is in line with the provisions of the CERC (Communication System for Inter-State transmission of electricity) Regulations, 2017.

8.1.1 Objective of Communication Code

The Objective provision of the Communication Code is as below:

48.1. These regulations provide for planning, implementation, operation and maintenance and up-gradation of reliable communication system for all communication requirements including exchange of data for integrated operation of State Grid.

(a) To ensure seamless integration, reliable, redundant and secure communication;

(b) To ensure that any network change shall not cause any adverse effect on functioning of existing Communication System. The Communication System shall continue to perform intended function with specified reliability, security and quality;

(c) A Data Provider or an intervening Communication System Provider is required to be aware, in advance, of the latest standards and conditions to be met by its system for being connected into the Communication System.

8.1.2 Applicability of Communication Code

All the Users connected with the InSTS system shall comply with the provisions of the procedure formulated by the STU under the maintenance and testing procedures. Thus, the Commission proposes the following:

53.1. All Users that have provided the communication systems shall facilitate for periodic testing of the communication system in accordance with procedure for maintenance and testing to be prepared by STU within 60 days of notification of Regulations and approved by GCC.

8.1.3 Nodal Agency for Implementation of Communication Code

MSLDC shall act as the nodal agency for the integration of Communication System in the Intra-State network. The SLDC shall, in turn, provide operational feedback to the STU and CTU.

49 Role of SLDC

49.1. SLDC shall be nodal agency for integration of Communication System in the Intra-State network at SLDC end for monitoring, supervision and control of Power System.

49.2. SLDC shall provide operational feedback to CTU and STU.

8.1.4 Key Provisions of Communication Code

The key provisions of the Communication Code are as below:

a) Roles and Responsibilities of the State Entities, STU and SLDC
b) Boundary of Communication System
c) Periodic Testing of the Communication System
d) Periodic Auditing of Communication System
e) Fault Reporting
f) Communication System Availability and Backup

8.1.5 Monitoring and Reporting of Communication System Performance

All Users/Transmission Licensees shall monitor and keep record of the month-wise Communication System (SCADA RTU) Availability Index and Average Duration of Downtime per month (in Minutes) for AMR System at each Connection Point and submit report for the past six-monthly performance during next Metering & Communication Coordination Committee (MCCC) meeting.

MCCC shall review and deliberate on the cause of the significant variations in indices from the normal range (below 99.9% for Communication System (SCADA/RTU) Availability Index and more than 60 minutes/month in case of Average duration of Downtime for AMR system) and guide the remedial actions for the improvements.

STU in consultation with MCCC shall formulate detailed procedure for measurement, monitoring and reporting of the Communication System Index (for SCADA/RTU) and Average duration of Downtime (for AMR System) at Connection Point covering intra-state transmission network. STU shall publish such report on its website from time to time.

8.1.6 Cyber Security

The communication infrastructure shall be planned, designed and executed to address the network security needs as per the standards specified by the CEA and shall be in conformity with the Cyber Security Policy of the Government of India, issued from time to time. A new provision of Cyber Security has been added to the MEGC. This provision mandates identification of Critical Information Infrastructure and provides necessary measures in accordance with the guidelines issued by the appropriate authorities.

STU in assistance with SLDC shall prepare a Crisis Management Plan and/or procedure in line with the Information Technology (IT) Act 2002, as amended from time to time and any other rules or policy or guidelines relevant to the subject, within one year from the date of notification of these Regulations, to ensure that adequate Cyber Security mechanism is available with all the Users to prevent any potential cyber-attack on the systems and submit for approval of the GCC.

An appropriate communication or IT network may be built up preferably using Multi-Protocol Label Switching, which is simple, cost-effective and reliable. In the remote areas, where connectivity is a problem, the stations can use dedicated fibre cable from the nearest node. Such communication or IT network may be built using dedicated fibres to avoid any cyber-attack on the power system.

Regular Cyber Vulnerability Test/Mock Drills/Cyber Audit/and other measures as per the crisis management plan of the Indian Computer Emergency Response Team (ICERT) shall be carried out regularly by all the Users. The frequency of such Audits/Mock Drills shall be decided by the STU in the Procedure/Guidelines stipulated as per Regulation 1.1.

A Cyber Audit specifically to detect malware targeting Industrial Control Systems (ICS) shall be conducted at critical plants and substations after any abnormal event.

A dedicated team of IT personnel for cybersecurity in all the substations and/or a group of substations shall be developed and proper training for the team members shall also be conducted regularly by the respective organizations to upgrade their skills.

SLDC shall monitor the case of cybersecurity incidences and discuss at State level and take necessary action as deemed fit.

GCC shall ensure that third party Cyber Security Audit shall be conducted periodically (period to be decided by GCC) and appropriate measures shall be implemented to comply with the findings of the audit. The audit shall be conducted by CERT-In certified third party auditors.

9 Part G: Protection Code

9.1.1 Objective of Protection Code

The Commission has introduced the Protection Code as a separate Code within the draft MEGC Regulations, 2020 to emphasis on the importance of the protection schemes within the InSTS.

9.1.2 Applicability of Protection Code

The Protection Code is applicable to all the Users connected with InSTS system and the STU shall be primarily responsible for monitoring appropriate settings of the protection system. All Users shall co-operate with the STU to ensure correct and appropriate settings of protection system to achieve effective, discriminatory removal of faulty equipment within the time for target clearance as specified in the Regulations.

9.1.3 Nodal Agency for Implementation of Protection Code

The STU shall be the nodal agency for the implementation of the Protection Code and shall coordinate with the Protection Coordination Committee (PCC) to be constituted under GCC.

STU in consultation with PCC shall prepare Protection Manual within three months from the notification of these Regulations. STU also shall consult with the stakeholders and GCC and also consider the on-field experience and operational best practices followed in other states while developing the Protection Manual.

9.1.4 Key Provisions of Protection Code

The following key provisions are proposed in the Draft Protection Code:

59.9. The Protection Code prepared by STU shall contain provisions for the following:

(a) Role and responsibility of STU /SLDC and Users

(b) Protection System for Generators

(c) Protection System for Transmission Lines including HVDC

(d) Protection System for substations and Transmission to Distribution interface.

(e) Compliance monitoring of the Protection Code by the Users

(f) Calibration and testing of the equipment and Relays used in the protection system

(g) Type of communication required for protection system

(h) Protection Audit

(i) Any other provisions that STU deem fit as required for system

The proposed provisions are in line with the regulations and manual issued by the CEA. The STU shall ensure that the provisions of the Protection Code shall be consistent with the following:

(a) Protection Philosophy

(b) CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007

(c) CEA (Technical Standards for Construction of Electrical Plants and Electric Lines), 2010

(d) CEA (Grid Standards) Regulations, 2010

(e) CEA Transmission Planning Criteria, 2013

(f) Protection standard adopted by WRLDC/WRPC

(g) System requirement and experience of STU

9.1.5 Revision in the Protection Manual and Best practices Guidebook

Transmission Licensees shall prepare share the best practices of protection system development, operations and safety practices. Protection Coordination Committee (PCC) shall coordinate and formulate a forum of technical experts from industry and academia for continuous improvement in the knowledge of protection systems, preventive measures, monitoring and reporting of best practices.

The events of protection system/switchgear/relay/device failure as well as the events leading to successful operation of the protection system/switchgear/ relay/device should be recorded and deliberated during PCC committee meetings.

Review of the Protection Manual for upgradation/modification shall be undertaken at least once in a year. Such review would cover the important developments/events at national/regional level, need for periodic review due to upgradation of technical standards for switchgear/devices, technological innovations, use of IT tools/practices, training and capacity building requirements. Based on the review, the PCC shall recommend suitable modifications/amendments to Protection Manual which shall be duly incorporated in timebound manner upon following due stakeholder consultation process.

10 Part H: Metering Code

The Commission has notified MERC (Deviation Settlement Mechanism and related matters) Regulations, 2019 on 1 March 2019. As per the provisions of the MERC DSM Regulations and Statement of Reasons (SOR) to DSM Regulations, the Commission directed the STU to undertake the review of the Metering Code under MERC State Grid Code, 2006. Accordingly, the STU constituted the Metering Code Committee under the convenorship of CE, STU.

The Metering Code Committee reviewed the existing Metering Code and prepared the revised draft Metering Code in line with the provisions of the CEA Metering Regulation, IEGC provisions and other relevant Regulations. The STU published the draft Metering Code on its website for stakeholder comments. The STU received the comments/suggestions from the stakeholders on the draft Metering Code. The comments/suggestions of the stakeholders were discussed in the meetings of the metering committee. Considering the Stakeholder’s comments and suggestion, Metering Committee revised the Draft Metering Code and submitted to the Commission for approval on 3 September,2019.

The Commission reviewed the draft Metering Code submitted by the STU and approved the draft Metering Code on 5 December 2019 and directed STU to publish the approved copies on STU’s website. This approved Metering Code shall form Part H of these Regulations and shall be read with other sections of MEGC, as necessary.

The stakeholders are expected to refer the approved Metering Code dated 5 December 2019 with this State Grid Code for reference only.

11 Part I: Miscellaneous

11.1.1 Objective

The objective of this Code is to list out all the data required to be provided by the Users to STU and the data required by the Users to be provided by STU and SLDC in accordance with the provisions of these Regulations.

11.1.2 Applicability

The provisions of the Code shall be applicable to all the User of InSTS. All the Users shall maintain the data and submit to the STU/MSLDC as per the requirement of the Grid Code. Responsibility for the correctness of data rests with the concerned User providing the data.

11.1.3 Key Provisions

The Draft Regulations provides for the details of the method for submission of data by the User with the STU/MSLDC. The data shall be furnished in the standard formats to MSLDC/STU. In case any data is missing and is not supplied by the STU, the concerned User may take appropriate action. Further, if necessary, the STU/MSLDC may estimate such data depending upon the urgency of the situation. Such estimates will, in each case, be based upon the corresponding data for similar plant or apparatus or upon such other information, the User or STU or SLDC, as the case may be.

The Commission has mandated the STU to perform frequent load flow studies for the purpose of expansion and network augmentation and suggested the types of load flow studies to be performed. The studies shall encompass both transient as well as steady state studies.

11.1.4 Compliance Monitoring

A separate chapter on monitoring and compliance code has been added which provides for audit for the performance of all users, STU and SLDC with respect to grid code compliance shall be assessed periodically. All users, STU and SLDC shall conduct annual self-audits to review compliance of the regulations and submit by 31st July of every year. The Commission may order independent third-party compliance audit for any user, STU, SLDC as deemed necessary. This chapter also deals with monitoring of manner of reporting the instances of violations of MEGC and taking remedial steps or initiating appropriate action.

11.1.5 Procedures to be Prepared for implementation of MEGC

For implementation of MEGC, following procedures shall be prepared by STU and/or SLDC

#	Details of Procedure / Guidelines / Codes / Plans	Ref. Regulation	Responsible Entity
1	Transmission System Plan for 5 years	12	STU

#	Details of Procedure / Guidelines / Codes / Plans	Ref. Regulation	Responsible Entity
2	Guidebook for planning Code	13.2.6	STU
3	Integrated Resource Planning for 5 years	11	SLDC and STU
4	Procedure for operationalising spinning reserve margin	14.4.6	SLDC
5	Model Connection Agreement	21.1	STU
6	Procedure for preparation of SRS	26.1.5	STU
7	Procedures for a) Black start; b) System restoration for partial grid failure; c) Load curtailment; d) Renewable Energy curtailment; e) Islanding; and f) Any other procedure as required	28.2 and 43	SLDC
8	Procedure Congestion Management	44	STU and SLDC
9	Procedure for work to be carried out across an inter-User boundary	45.2	STU
10	Standard reporting format for event reporting	46.2.3	SLDC
11	Procedure for DC Demonstration of Generating Units	32.4	Provided as Annexure 3
12	Guidelines for Instructing RSD of Generating Unit	36	SLDC
13	Procedure for Accounting and Settlement of InSTS Reactive Energy Charges	37.16	Provided as Annexure 7
14	Procedures, Formats and Timelines for Demand Estimation	38.1	SLDC
15	Contingency Procedures under Demand Curtailment	39.3.3	Licensee/user/STU
16	Guidelines/Standard Reporting Format for Reportable Events	36.2.3	SLDC/Licensee/user
17	Procedure for Testing and Maintenance of Communication Network Security System	53.1	STU
18	Procedure for Crisis Management Plan and procedure under Cyber Security.	58.2	STU
19	Guidelines/Procedure on Interfacing Requirements	59.1(a)	SLDC
20	Procedure on Centralized supervision for quick Fault Detection and Restoration	59.1(b)	STU
21	Procedure on Maintenance and testing of Communication System	59.1(b)	STU
22	Guidelines on Availability of Communication System	59.1(c)	STU
23	Protection Manual	60.67	STU