

RNI No. KARBIL/2001/47147



# ಕರ್ನಾಟಕ ರಾಜ್ಯಪತ್ರ

ಅಧಿಕೃತವಾಗಿ ಪ್ರಕಟಿಸಲಾದುದು

ಬಿಶೇಷ ರಾಜ್ಯ ಪತ್ರಿಕೆ

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KARNATAKA ELECTRICITY REGULATORY COMMISSION

No. 9/2, 6<sup>th</sup> & 7<sup>th</sup> Floors, Mahalaxmi Chambers, M.G.Road, Bengaluru - 560001

NOTIFICATION

No. KERC/J/02/1/2000, Dated: 02-02-2016

## KARNATAKA ELECTRICITY GRID CODE [KEGC], 2015

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**KARNATAKA ELECTRICITY REGULATORY COMMISSION**

**Karnataka Electricity Grid Code (KEGC), 2015**

Notification No. M/28/14 Dated //-//- 2015

**SECTION – 1  
GENERAL**

**PREAMBLE**

The Karnataka Electricity Grid Code (KEGC), is a Regulation made by the Karnataka Electricity Regulatory Commission in exercise of powers under clause (h) of subsection (1) of Section 86 read with clause (zp) of sub-section (2) of Section 181 of the Act. The Karnataka Electricity Grid Code lays down the rules, guidelines and standards to be followed by various persons and participants in the Intra-State Transmission system to plan, develop, maintain and operate the power system, in the most secure, reliable, economic and efficient manner, so as to meet the requirements of Integrated Operation with the Inter-State Transmission system of the Southern Regional Grid/ National Grid as per the provisions of the Indian Electricity Grid Code while facilitating healthy competition in the generation and supply of electricity.

**NOTIFICATION**

In exercise of powers conferred under clause (h) of sub-section (1) of Section 86 read with clause (zp) of sub-section (2) of Section 181 of the Electricity Act, 2003 (36 of 2003), and all other powers enabling it in this behalf, the Karnataka Electricity Regulatory Commission hereby makes the following regulations. -

**1. Short title, extent and commencement**

- a. These Regulations shall be called the Karnataka Electricity Regulatory Commission (Karnataka Electricity Grid Code) Regulations, 2015.
- b. These Regulations shall come into force from the date of publication in the official Gazette of Karnataka.
  - (i) These regulations shall supersede the Karnataka Electricity Grid Code (KEGC), 2005 notified along with KEDC which came into effect from 26.01. 2006.

## 1.1 Introduction

The Karnataka Power System is a conglomeration of a number of agencies viz Generators, CTU, STU, SLDC, DISCOMs and other users. Power system means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely: -

- (a) Generating stations;
- (b) Transmission or main transmission lines;
- (c) Sub-stations;
- (d) Tie-lines;
- (e) Load despatch activities;
- (f) Mains or distribution mains;
- (g) Electric supply-lines;
- (h) Overhead lines;
- (i) Service lines;
- (j) Works;

## 1.2 Objective

The KEGC Covers a single set of technical and commercial rules, encompassing all the Utilities connected to/or using the intra-State transmission system (In-STs) and provides the following:

- 1) Defines the relationship between the various Users of the Intra-State transmission system (In-STs), State and Area Load Despatch Centers.
- 2) Facilitation of the optimal operation of the Intra-State grid.
  - i. To ensure that the transmission system within the State is operated in an efficient and reliable manner.
  - ii. To ensure electricity fed into the grid from the generators within and outside the State reaches to the DISCOMs or the end consumers and facilitates open access facility to the consumers.
  - iii. To maintain the frequency, interruptions and harmonics within the stipulated limits.
- 3) Facilitation of coordinated and optimal maintenance planning of generation and transmission facilities in the intra-State grid.
- 4) Facilitation of development and planning of economic and reliable intra-State grid in coordination with the National / Regional Grid.

- 5) Facilitation of integration of renewable energy sources by specifying the technical and commercial conditions.

### 1.3 Scope

The Users namely, STU, SLDC, ALDCs, DISCOMs and Generators are required to abide by the principles and procedures defined in the KEGC in so far as they apply to that party.

### 1.4 Structure of the KEGC

This KEGC comprises of following chapters:

Section -1	General
SECTION-2	Definitions
SECTION-3	Management of Grid Code and Role of various Organizations
SECTION-4	Planning Criteria for Intra-State Transmission
SECTION-5	Grid Connectivity
SECTION-6	Operation Planning
SECTION-7	Cross Boundary Safety
SECTION-8	Scheduling and Despaching
SECTION-9	Protection and Metering
SECTION-10	Miscellaneous Issue of orders and practice directions
ANNEXURES	

## SECTION-2

### DEFINITIONS

#### 2. Definitions

(l) In these Regulations unless the context otherwise requires:

- 2.1** “**Act**” means the Electricity Act, 2003, as amended from time to time;
- 2.2** “**Ancillary Services**” means in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, such as but not limited to active power support for load following, reactive power support, black start;
- 2.3** “**Area Load Despatch Centre (ALDC)**” means the centre as established by the STU to carry out the instructions of SLDC for controlling system operation in its jurisdiction and performing all duties assigned to it as stated in this Karnataka Electricity Regulatory Commission Grid Code (KEGC);
- 2.4** “**Automatic Voltage Regulator (AVR)**” means a continuously acting automatic excitation control system to control the voltage of a Generating Unit measured at the generator terminals;
- 2.5** “**Backing Down**” means reduction of generation by a generating unit on instructions from SLDC/ SRLDC;
- 2.6** “**Beneficiary**” means a licensee who has a share in an Inter-State Generating Station (ISGS) and/or Intra-State Generating Station (In-SGS);
- 2.7** “**Bilateral Transaction**” means a transaction for exchange of energy (MWh) between a specified buyer and a specified seller, directly or through a trading licensee or Power Exchange from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for a specified period;
- 2.8** “**Black Start Procedure**” means the procedure to recover **the grid** from partial or a total blackout in the State;

- 2.9** “**BIS**” means the Bureau of Indian Standards;
- 2.10** “**Bulk Consumer**” means any Consumer who avails supply at voltage of 33 kV and /or above;
- 2.11** “**Capacitor**” means an electrical facility provided for generation of reactive power;
- 2.12** “**Captive Power Plant**” means a Power Plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such co-operative society or association;
- 2.13** “**CERC**” means the Central Electricity Regulatory Commission;
- 2.14** “**CEA**” The Central Electricity Authority of India (CEA) is a statutory organisation constituted under section 70(1) of the Electricity Act 2003.
- 2.15** “**Central Generating Station (CGS)**” means the generating station owned by the companies that are owned or controlled by the Central Government;
- 2.16** “**Central Transmission Utility (CTU)**” means any Government Company which the Central Government may so notify under sub-section (1) of Section 38 of the Act;
- 2.17** “**Collective Transaction**” means a set of transactions discovered in power exchange through anonymous, simultaneous competitive bidding by buyers and sellers;
- 2.18** “**Commission**” means the Karnataka Electricity Regulatory Commission (K.E.R.C.);
- 2.19** “**Connection Agreement**” means an Agreement between STU, intra-State transmission licensee(s) other than STU (if any) and any person setting out the terms relating to a connection to and/or use of the Intra- State Transmission System;
- 2.20** “**Connection Point**” means a point at which a plant (generating station or a substation or bulk consumer) and associated equipment connects to the Transmission System;



- 2.21 “Connectivity”** means the state of getting connected to the Intra-State transmission system by a generating station, including a captive generating plant, a bulk consumer or Intra- State transmission licensee;
- 2.22 “Control Area”** means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas whenever required to do so and contributes to frequency regulation of the synchronously operating system;
- 2.23 “Control Person”** means a person identified as having technical capability and responsibility for cross boundary safety under Regulation 7 of this Grid Code.
- 2.24 “Demand”** means the demand of Active Power in MW and Reactive Power in MVar of electricity.
- 2.25 “Despatch Schedule”** means the ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time;
- 2.26 “Data Acquisition System (DAS)”** means a system provided to record the sequence of operations in real time, of the relays/equipment as well as the measurement of pre-selected system parameters;
- 2.27 “Disturbance Recorder (DR)”** means a device provided to record the behavior of the preselected digital and analog values of the system parameters during an event (including a few cycles of pre-fault condition);
- 2.28 “Drawal Schedule”** means the summation of the station-wise ex-power plant drawal schedules from all ISGS and In-SGS and drawal from / injection to the DISCOMs (State grid) consequent to long term, medium term and short term open access transactions;
- 2.29 “Entitlement”** means a share of a beneficiary (in MW / MWh) in the installed capacity/output capability of an Inter-State Generating Station (ISGS) and/or Intra-State Generating Station (In-SGS);
- 2.30 “Entity”** means the person who is in the control area of SLDC and whose metering and energy accounting is done within the state;

- 2.31 “Event”** means an unscheduled or unplanned occurrence on a Grid including faults, incidents and breakdowns;
- 2.32 “Event Logging Facilities”** means a device provided to record the chronological sequence of operation, of the relays and other equipments;
- 2.33 “Ex-Power Plant Schedule”** means net MW/MWh output of a generating station, after deducting auxiliary consumption and transformation losses within the generating station;
- 2.34 “Fault Locator (FL)”** means a device provided at the end of a transmission line to measure/ indicate the distance at which a line fault may have occurred;
- 2.35 “Flexible Alternating Current Transmission System (FACTS)”** means power electronics based system and other static equipment that provide a control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability;
- 2.36 “Force Majeure”** means any event which is beyond the control of the persons involved which they could not foresee or with a reasonable amount of diligence could not have foreseen or which could not be prevented and which substantially affects the performance by a person such as the following including but not limited to:-
- i. Acts of God, natural phenomena, floods, droughts, earthquakes and epidemics;
  - ii. Enemy acts of any Government domestic or foreign, war declared or undeclared, hostilities, priorities, quarantines, embargoes;
  - iii. Riot or Civil Commotion;
  - iv. Grid's failure not attributable to the person.
- 2.37 “Forced Outage”** means an outage of a Generating Unit or a transmission facility due to a fault or other reasons which has not been planned;
- 2.38 “Generation Schedule”** means a dispatch schedule of a generating station.
- 2.39 “Good Utility Practices”** mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period which could have been expected to

accomplish the desired results at a reasonable cost consistent with good business practices, reliably, safely and with expedition;

- 2.40 “Governor Droop”** means in relation to the operation of the governor of a Generating Unit, the percentage drop in system frequency which would cause the Generating Unit under **restricted or free governor** action to change its output from zero to full load;
- 2.41 “Grid Standards”** means the standards specified by the Authority (CEA) under clause (d) of the Section 73 of the Act;
- 2.42 ‘Gaming’** in relation to these regulations, shall mean an intentional mis-declaration of declared capacity by any generating station or seller in order to make an undue commercial gain through Charge for Deviations;
- 2.43 “Independent Power Producer (IPP)”** means a generating company not owned/ controlled by the Central/State Government;
- 2.44 “Indian Electricity Grid Code (IEGC)”** means the regulations specified by the CERC in exercise of powers under clause (h) of subsection (1) of Section 79 read with clause (g) of sub-section (2) of Section 178 of the Act;
- 2.45 “Indian Standards (IS)”** Those standards and specifications approved by the Bureau of Indian Standards(BIS);
- 2.46 “Interconnecting Transformers (ICTs)”** means Transformers connecting lines of different voltage;
- 2.47 “Inter-State Generating Station (ISGS)”** means a Central generating station or other generating station, in which two or more states have shares or have contracts to buy power;
- 2.48 “Inter-State Transmission System (ISTS)”** includes any system for the conveyance of electricity by means of a main transmission line from the territory of one State to another State:
- (i) The conveyance of electricity across the territory of an intervening State as well as conveyance within the State which is incidental to such inter-state transmission of energy;
  - (ii) The transmission of electricity within the territory of the State on a system built, owned, operated, maintained or controlled by CTU;

- 2.49 “Intra-State Generating station (In-SGS)”** means a Generating station located within the geographical area of the State of Karnataka;
- 2.50 “Intra-State Transmission System (In-STS)”** means a system of Transmission Lines and substations built, owned, operated and maintained or controlled by the STU or a transmission licensee for conveyance of electricity within the territory of the State;
- 2.51 “Karnataka Electricity Grid Code (KEGC)”** means the Regulations specifying the philosophy and the responsibilities for planning, developing and operation of the Karnataka Power System;
- 2.52 “Karnataka Electricity Distribution Code (KEDC) or Distribution Code”** means the Regulations specifying the philosophy and the responsibilities for planning, developing and operation of the Distribution System;
- 2.53 “Lean Period”** refers to that period in a day/Month/Year when the electrical power demand is low;
- 2.54 “Licensee”** means a person who has been granted a licence under Section 14 of the Act;
- 2.55 “Light Load”** means the simultaneous minimum demand of the system occurring under specific time duration (e.g. annual, monthly, daily etc);
- 2.56 “Long –term Access”** means the right to use the intra-State transmission and distribution system as defined in the KERC (Open Access) Regulations, 2004, as amended from time to time;
- 2.57 “Long-term customer”** means a person who has been granted long-term access in the State;
- 2.58 “Main Protection”** means the protection equipment or system expected to have priority in initiating either a fault clearance or an action to terminate an abnormal condition in the power system;
- 2.59 “Maximum Continuous Rating (MCR)”** means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters;

- 2.60 “Medium-term Open Access”** means the right to use intra- State transmission and distribution system from any generating station for a period exceeding three months but less than three years.
- 2.61 “Medium-term customer”** means a person who has been granted a medium-term open access;
- 2.62 “National Grid”** means the entire inter-connected electric power network of the country;
- 2.63 “Net Drawal Schedule”** means the drawal schedule of a DISCOM after deducting the apportioned transmission losses (estimated);
- 2.64 “NLDC”** means the National Load Despatch Centre established under sub-section (1) of Section 26 of the Act;
- 2.65 “Open Access”** means the non-discriminatory provision for the use of transmission lines or distribution system or associated facility with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Commission;
- 2.66 “Operation”** means a scheduled or planned action relating to the operation of a System;
- 2.67 “Operation Coordination Sub-Committee (OCC)”** means a sub-committee of RPC with members from all the regional entities which decide the operational aspects of the Regional Grid;
- 2.68 “Operating range”** means the operating range of frequency and voltage as specified under the Operating Code;
- 2.69 “Outage”** means a total or partial reduction in availability due to repair and maintenance of the transmission or distribution or generation facility or defects in the auxiliary system;
- 2.70 “Partial Grid Disturbances”** means a shutdown of part of the system, resulting in failure of power supply to that part of the system;
- 2.71 “Peak Load”** means the simultaneous maximum demand of the system occurring under specific time duration (e.g. annual, monthly, daily etc);

- 2.72 “Power grid”** means the Power Grid Corporation of India Limited which has been notified as CTU;
- 2.73 “Power Exchange”** means the power exchange which has been granted registration in accordance with CERC (Power Market Regulations), 2010 as amended from time to time;
- 2.74 “Power System”** means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely;
- (a) Generating stations;
  - (b) Transmission or main transmission lines;
  - (c) Sub-stations;
  - (d) Tie-lines;
  - (e) Load despatch activities;
  - (f) Mains or distribution mains;
  - (g) Electric supply lines;
  - (h) Overhead lines;
  - (i) Service lines;
  - (j) Works;
- 2.75 “Regional Power Committee (RPC)”** means a Committee established by resolution by the Central Government for a specific region for facilitating the integrated operation of the power systems in that region;
- 2.76 “Regional Energy Account (REA)”** means a regional energy account prepared on monthly basis by the RPC Secretariat for the billing and settlement of ‘Capacity Charge’, ‘Energy Charge’ and Transmission charges;
- 2.77 “Regional Grid”** means the entire synchronously connected electric power network of the concerned Region;
- 2.78 “Regional Load Despatch Centre (RLDC)”** means the Centre established under sub-section (1) of Section 27 of the Act;
- 2.79 “Short-term Open Access”** means open access for a period up to three months;
- 2.80 “Spinning Reserve”** means part loaded generating capacity with some reserve margin that is synchronized to the system and is ready to provide

increased generation at short notice pursuant to Despatch instruction or instantaneously in response to a frequency drop;

- 2.81 “Standing Committee for Transmission Planning”** means a Committee constituted by the CEA to discuss, review and finalize the proposals for expansion or modification in the ISTS and associated intra-state systems;
- 2.82 “State Load Despatch Centre (SLDC)”** means the Centre established under subsection (1) of Section 31 of the Act;
- 2.83 “State Transmission Utility (STU)”** means the Government Company specified as such by the State Government under sub-section (1) of Section 39 of the Act;
- 2.84 “Static VAR Compensator (SVC)”** means an electrical facility designed for the purpose of dynamically generating or absorbing Reactive Power;
- 2.85 “Supervisory Control and Data Acquisition (SCADA)”** means the communication links and data processing systems which provide information to enable implementation of requisite supervisory and control access.
- 2.86 “Surge Impedance Loading”** means the unity power factor load over a resistive line such that series reactive loss ( $I^2X$ ) along the line is equal to shunt capacitive gain ( $V^2Y$ );
- 2.87 “Switching over-voltages”** means over-voltages generated during switching of lines, transformers and reactors etc., having wave fronts 250/2500 micro second;
- 2.88 “System Stability”** means a stable power system is one in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. Usually the perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped;
- 2.89 “Temporary over-voltages”** means the power frequency over-voltages produced in a power system due to sudden load rejection, single phase to ground faults, etc.,

- 2.90** “**Time Block**” means block of 15 minutes each for which Special Energy Meters record values of specified electrical parameters with first time block starting at 00.00 Hrs;
- 2.91** “**Transmission Licence**” means a Licence granted under Section 14 of the Electricity Act, 2003 to transmit electricity;
- 2.92** “**Transmission Planning Criteria**” means the policy, standards and guidelines issued by the CEA for the planning and design of the Transmission system;
- 2.93** “**Transmission Reliability Margin (TRM)**” means the amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions;
- 2.94** ‘**Deviation**’ in a time-block for a seller means its total actual injection minus its total scheduled generation and for a buyer means its total actual drawal minus its total scheduled drawal.
- 2.95** “**User**” means a person such as a Generating Company including Captive Generating Plant or Transmission Licensee (other than the Central Transmission Utility and State Transmission utility) or Distribution Licensee or Bulk Consumer, whose electrical plant is connected to the In-STS at a voltage level 33 kV and above.

(II) Words and expressions used and not defined herein these Regulations but defined in the Act or any Regulations made under the act shall have the meaning assigned to them under the Act or Regulations.



## SECTION-3

### MANAGEMENT OF GRID CODE AND ROLE OF VARIOUS ORGANIZATIONS

#### 3.1 INTRODUCTION:

- 3.1.1 The Karnataka Power Transmission Corporation Limited (KPTCL), which is the State Transmission Utility (STU), that also holds the Transmission Licence required to implement and ensure compliance with the Karnataka Electricity Grid Code (KEGC), herein after called GRID CODE, and to carry out periodic review and seek for amendments of the same. A Review Panel shall be constituted by the STU, as required in this Section, comprising of the representatives of the Users of the Transmission System.
- 3.1.2 No change in this GRID CODE, however small or big, shall be made without being deliberated upon and agreed to by the GRID CODE Review Panel and approved by the Commission.
- 3.1.3 The STU will be responsible for managing and implementing the GRID CODE for discharging its obligations with the Users. The STU will not be, however, required to incur any expenditure on account of travel etc., of any other member of the panel other than its own representative.

#### 3.2 OBJECTIVE:

- 3.2.1 The objective of this Section is to define the method of management of GRID CODE documents, implementing any changes/modifications required and the responsibilities of the constituents (Users) to effect the change.

#### 3.3 GRID CODE REVIEW PANEL:

- 3.3.1 The Chairperson of the Grid Code Review panel shall be an Engineer of the STU not below the rank of Chief Engineer (Electricity). The Member Secretary of the Panel shall also be nominated by the STU. The Panel shall consist of the following members on the recommendations of the heads of the respective organizations:

- a) Chief Engineer of the State Load Despatch Centre (SLDC)
- b) One Chief Engineer or General Manager of the Karnataka Power Corporation Limited (KPCL).
- c) One senior representative from the Southern Regional Power Committee (SRPC).

- d) One representative at senior executive level from the National Thermal Power Corporation Limited (NTPC).
  - e) One representative at senior executive level from the Power Grid Corporation of India Limited (PGCIL).
  - f) One representative at senior executive level from the Southern Regional Load Despatch Centre (SRLDC).
  - g) One representative at senior executive level from each Distribution & Retail Supply Licensee.
  - h) One representative at senior executive level from each of the IPPs feeding the Karnataka State Power Grid and feeding not less than 50 MW.
  - i) One representative from all the IPPs and CPPs of small Power Plants of less than 50 MW capacity on rotation basis.
- 3.3.2** Any other member can be co-opted as a member of the Panel when directed by the Commission.
- 3.3.3** The functioning of the Panel shall be coordinated by the STU. The Member Secretary nominated by the STU shall be the convener.
- 3.3.4** The STU shall inform all the Users, the names and addresses of the Panel Chairperson and the Member Secretary at least seven days before the first meeting of the Panel. Any subsequent changes shall also be informed to all the users by the STU. Similarly, each User shall inform the names and designations of their representatives to the Member Secretary of the Panel, at least three days before the first Panel meeting, and shall also inform the Member Secretary in writing regarding any subsequent changes.

#### **3.4 FUNCTIONS OF THE REVIEW PANEL:**

**3.4.1** The functions of the Review Panel are as follows:

- (a) Maintenance of the GRID CODE and its working under continuous scrutiny and review.
- (b) Consideration of all requests for review made by any User and publication of their recommendations for changes to the GRID CODE together with reasons for such changes.
- (c) Issue of guidance on interpretation and implementation of the GRID CODE.
- (d) Examination of the problems raised by any User.
- (e) Ensuring that the changes/modifications proposed in the GRID CODE are consistent and compatible with Indian Electricity Grid Code (IEGC).

- (f) Analysis of major grid disturbances soon after their occurrence.
- (g) Review the progress of the committee formed for coordination and monitoring of protection functions for the entire grid.

The Review Panel may hold as much number of meetings as required subject to the condition that at least one meeting shall be held in every three months. Sub-meetings may be held by the STU with the User to discuss individual requirements and with groups of Users to prepare proposals for Panel meeting for taking a decision.

### **3.5 REVIEW AND REVISIONS:**

- 3.5.1** The Users seeking any amendment to the Grid Code shall send written requests to the Member Secretary of the panel with a copy to the Commission. If the request is sent to the Commission directly, the same shall be forwarded to the STU. The STU shall, in consultation with the Distribution & Retail Supply Licensees, Generating Companies, Central Transmission Utility (CTU), SRLDC and such other persons as the Commission may direct, review the GRID CODE provisions after proper examination.
- 3.5.2** All the comments received from the members of the Panel shall be scrutinized and compiled by the STU. These comments, along with comments of STU shall be sent to all the members for their response in favour or otherwise, for the proposed change/modification. If necessary, the STU shall convene a meeting of the Panel for deliberations. The Member Secretary shall present all the proposed revisions of the Grid Code to the Panel for its consideration.
- 3.5.3** Based on the response received, the STU shall finalize its recommendation regarding the proposed modification / amendment and submit the same along with all the related correspondence to the Commission for approval. The KERC shall approve the same after holding a Public Hearing.
- 3.5.4** The STU shall send the following reports to the Commission at the conclusion of each review meeting of the Panel:
  - i. Reports on the outcome of such review.
  - ii. Any proposed revision to the Grid Code as the STU reasonably thinks necessary for achievement of the objectives referred to in the relevant paragraphs.
  - iii. All written representations and objections submitted by the Users at the time of review.

**3.5.7** The STU shall keep copies of the Grid Code with the latest amendments and shall make it available at a reasonable cost to any person requiring it.

### **3.6 Non-Compliance**

- i. If any user fails to comply with any provision of the Grid Code the user shall inform the SLDC and Grid Code Review Panel without delay the reasons for its non-compliance and shall remedy its non-compliance promptly.
- ii. SLDC shall bring the non compliance to the notice of the Commission.
- iii. Consistent failure to comply with the Grid Code provisions may lead to disconnection of the user's plant and / or facilities.

### **3.7 Code Responsibilities**

- i. In discharging its duties under the Grid Code, STU shall rely on information which shall be furnished by the Users.
- ii. STU shall not be held responsible for any consequences that arise from its reasonable and prudent actions on the basis of such information.

### **3.8 Confidentiality**

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

### **3.9 Dispute Settlement Procedures**

- 3.9.1. In the event of any dispute regarding interpretation of any part/section of the Grid Code provision between any User and STU, the matter may be referred to the Commission for its decision. The Commission's decision shall be final and binding.
- 3.9.2. In the event of any conflict between any provision of the Grid Code and any contract or agreement between STU and Users, the provision(s) of the Grid Code shall prevail.

### **3.10 Directives**

- i. Any directions issued by the State Government under section 37 of the Electricity Act 2003, shall be promptly informed to the Commission and all

- Users by STU.
- ii. Any directives issued by the Commission from time to time shall be complied with by STU and all Users.

### **3.11 Compatibility with Indian Electricity Grid Code**

This Grid Code is consistent/compatible with the IEGC. However, in matters relating to inter-State transmission, if any provision of the State Electricity Grid Code is inconsistent with the provisions of the IEGC, then the provisions of IEGC as notified by CERC shall prevail.

### **3.12 Role of various Organizations**

#### **3.12.1 Role of SLDC**

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

- (i) The State Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in the State.
- (ii) The State Load Despatch Centre shall,—
  - a) be responsible for optimum scheduling and despatch of electricity within the State, in accordance with the contracts entered into with the licensees or the generating companies operating in the State;
  - b) monitor grid operations;
  - c) keep accounts of the quantity of electricity transmitted through the State Grid;
  - d) exercise supervision and control over the intra-State transmission system; and
  - e) be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the Grid Code.
- (iii) The following are contemplated as exclusive functions of SLDC:
  - a. Data acquisition and supervisory control, state estimation, security analysis.
  - b. System Operation and control of the state grid covering contingency analysis, contingency ranking and operational plan on real time basis by conducting operational load flow studies using real time data.

- c. Furnishing feedback to STU on planning, on the issues of transmission strengthening, system protection requirement, congestion /bottlenecks.
  - d. Responsible for conducting demand forecast within the State, LGBR analysis, outage planning coordination & operation and analysis of the grid security.
  - e. Scheduling/ Re-scheduling of Generation.
  - f. System restoration following grid disturbances.
  - g. Metering and data collection of the energy transaction within the State Grid.
  - h. Compiling and furnishing data pertaining to system operation.
  - i. Operation of state Deviation Settlement Mechanism (DSM) pool account, state reactive energy account and other functions as directed by the Commission.
  - j. Display transmission line loadings, critical lines with contingent conditions and inform in writing to the STU on the transmission bottlenecks for remedial measures with a copy to the Commission.
  - k. Display of power map with power flow in the critical lines.
- (iv) In accordance with Section 33 of the Electricity Act, 2003, the State Load Despatch Centre in the State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in the State. Every licensee, generating company, generating station, sub-station and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre under subsection (1) of Section 33 of the Electricity Act, 2003. The State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre.
- (v) In case of inter-state bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State Transmission) Regulations, 2008, amended from time to time.

### **3.12.2 Role of ALDC :**

The Area Load Despatch centre shall:

- a. Comply with the directions of SLDC.
- b. Coordinate in outage management.
- c. Assist SLDC to ensure integrated operation of the power system in the State grid.
- d. Assist SLDC for monitoring the grid operations within its control area.

- e. Assist SLDC for supervision and control over the intra-State Transmission system, within its area and be responsible for carrying out real time operation.
- f. Keep accounts of the quantity of electricity transmitted through its control area.

### **3.12.3 Role of STU:**

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

- a) to undertake transmission of electricity through intra-State transmission system and inter State transmission under bilateral agreements;
- b) to discharge all functions of planning and co-ordination relating to intra-State transmission system with,
  - i) Central Transmission Utility;
  - ii) State Governments;
  - iii) Generating Companies;
  - iv) Regional Power Committees;
  - v) Central Electricity Authority (CEA);
  - vi) Licensees;
  - vii) Any other person notified by the State in this behalf;
- c) to ensure development of an efficient, congestion free, reliable, coordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centers;
- d) to provide non-discriminatory open access to its transmission system for use by,
  - i. any licensee or generating company on payment of the transmission charges; or
  - ii. any consumer as and when such open access is provided by the State Commission under sub-Section (2) of Section 42 of the Act, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.

### **3.14 UNTIL A GOVERNMENT COMPANY OR ANY AUTHORITY OR CORPORATION IS NOTIFIED BY THE STATE GOVERNMENT, THE STATE TRANSMISSION UTILITY SHALL OPERATE THE STATE LOAD DESPATCH CENTRE.**

## SECTION – 4

### PLANNING CRITERIA FOR INTRA-STATE TRANSMISSION

This section specifies the technical and design criteria and procedures to be adopted by STU for the planning and development of the Transmission System within its boundary.

#### 4.1 Introduction

- i. In accordance with Section 39(2)(b) of the Electricity Act, 2003, the State Transmission Utility (STU) shall discharge all functions of planning and coordination relating to intra-State transmission system with Central Transmission Utility, State Governments, Generating Companies, Regional Power Committees, Central Electricity Authority (CEA), licensees and any other person notified by the State Government in this behalf.
- ii. In accordance with Section 39(2) (d) of the Electricity Act, 2003, the State Transmission Utility (STU) shall inter-alia provide non-discriminatory open access to its transmission system for use by –
  - (a) Any licensee or generating company on payment of the transmission charges;  
or
  - (b) any consumer as and when such open access is provided by the State Commission under sub-section (2) of Section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.
- iii. In accordance with Section 40 of the Electricity Act, 2003, the STU shall build, maintain and operate an efficient, coordinated and economical intra- State transmission system and inter-alia provide non-discriminatory open access to its transmission system for use by
  - (a) any licensee or generating company on payment of the transmission charges;  
or
  - (b) any consumer as and when such open access is provided by the State Commission under sub-Section (2) of Section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.
- iv. In accordance with Section 3 (4) of the Electricity Act, 2003, CEA shall inter-alia prepare a National Electricity Plan in accordance with the National



- Electricity Policy and notify such plan once in five (5) years. In accordance with Section 3 (5) of the Electricity Act, 2003, CEA may review or revise the National Electricity Plan in accordance with the National Electricity Policy.
- v. In accordance with Section 73 (a) of the Electricity Act, 2003, CEA is responsible to advise the Central Government on the matters relating to the National Electricity Policy, formulate short-term and perspective plans for development of the electricity system and co-ordinate the activities of planning agencies for optimal utilization of resources to sub-serve the interests of the national economy and to provide reliable and affordable electricity for all consumers.
  - vi. The Planning Section specifies the philosophy and procedures to be applied in planning of the Intra-State Transmission System (In-STS) and the links to Regional Grid.

## 4.2 Objective

The objective of Planning criteria are as follows:

- (a) To specify the principles, procedures and criteria which shall be used in the planning and development of the Intra-State Transmission System (In-STS) and the links to Regional Grid.
- (b) To promote co-ordination amongst all Users, STU, CTU, RLDC, CEA in any proposed planning and development of the In-STS.
- (c) To provide methodology and information exchange amongst all Users, STU, SLDC, RLDC, RPC, and CEA for planning and development of the In-STS grid.

## 4.3 Scope

The Planning Criteria applies to STU, all users connected to and/or using and involved in developing the In-STS.

## 4.4 Perspective Plan

- 4.4.1** The Transmission Licensee shall file for Commission's approval a Perspective Plan on 1st April of the year preceding the first year of the Control period. The Perspective Plan shall be for a period of five years coinciding with the 5 year plan period of the Country and thereafter shall be for a period of 5 years in future. The Perspective

Plan for the Control Period shall inter alia contain the **consolidated load forecast submitted by all the Distribution Licensees, Generation Plan** and a Capital investment Plan. This shall be in accordance with the Practice Directions issued by the Commission in respect of Capital Investment programme and also consistent with the Regulations on Load Forecast. Further, the Transmission Licensee shall also revise the Perspective Plan every year taking into consideration of the changes occurred during the previous year and submit to the Commission as a Rolling Plan.

Load forecasting shall be carried out as per the KERC (Load Forecast) Regulations, 2009, not- inconsistent with the above Regulations the following may be adhered to. The Load forecasting shall be the primary responsibility of the Distribution Licensee within his area of supply. The Distribution Licensees shall determine the peak load and energy forecasts of their areas for each of the succeeding years and submit the same annually by 31st January, to STU. These shall include the details of demand forecasts, data methodology and assumptions on which the forecasts are based. The peak load and energy forecasts shall be made for the overall area of supply. The annual peak load forecast shall also be made for each Connection Point / Interface Point with the Transmission System. The peak load requirement at each Connection Point / Interface Point will essentially ensure that the STU may determine the corrective measures to be taken to maintain the capacity adequacy in the Transmission System up to the Connection Point /Interface Point. This will facilitate the Transmission Licensee to develop the compatible Transmission System. However, if the Distribution Licensee receives power at a number of Connection Points / Interface Points in a compact area, which are interconnected in a ring, then such a Distribution Licensee shall forward the overall long term demand forecast for the overall area of supply as well as at each Connection Point / Interface Point with the variation or tolerance, as mutually discussed and agreed upon with the STU. These forecasts shall be updated annually and also whenever major changes are made in the existing system. Wherever these forecasts take into consideration demands for power exceeding 5 MW by a single consumer, the Distribution Licensee shall personally satisfy himself regarding the materialisation of such a demand.

**4.4.2** The STU shall also review the methodology and assumptions used by the Distribution Licensees in making the load forecasts, in consultation with them. The resulting overall forecast will form the basis of planning for expansion of Transmission System, which will be carried out by STU. To maintain the reliability of the interconnected regional power systems, all participants must comply with the planning criteria/guidelines of CEA as updated from time to time.

**4.4.3** The STU shall forecast the demand for power within the area of supply for each of the succeeding years and provide to the Commission, the details of demand

forecasts, data, methodology and assumptions, on which the forecasts are based. Based on these forecasts and in coordination with the various agencies identified under section 39 (2) (b) of the Electricity Act 2003, STU shall be responsible to prepare and submit a long- term perspective plan to the Commission for the compatible intra-State transmission system expansion to meet the future demand. The planning shall be in conformity with the national perspective for Power Generation and Transmission Plan prepared by the CEA. This compatible intra-State transmission plan shall also include provision for reactive compensation needed for the Transmission System.

- 4.4.4** The STU shall be responsible for integrating the load forecasts submitted by each of the Distribution Licensees and determining the five-year load forecast on long-term perspective basis load forecasts for the State. For determining the requirements for the entire State, an appropriate diversity factor from the data available for the previous years shall have to be chosen. STU shall satisfy itself regarding the probability of materialisation of bulk loads of consumers with demands above 5 MW in consultation with the Distribution Licensees concerned. The STU shall extend full support to CTU to finalise the annual planning corresponding to a five-year forward term for identification of a major inter-State Transmission System including inter-regional schemes, which shall fit in with the long-term plan developed by CEA.
- 4.4.5** The STU shall furnish the requisite planning data to CTU by 31st March every year, to enable CTU to formulate and finalise the plan by 30th September each year, for the next five years.

#### **4.5 Planning Philosophy:**

- (a) CEA would formulate Perspective Transmission Plan for inter-State transmission system and STU would formulate perspective plan for intra-State transmission system. These perspective transmission plans would be continuously updated to take care of the revisions in load projections and generation scenarios, considering the seasonal and the time of the day variations. In formulating perspective transmission plan, the transmission requirement for evacuating power from renewable energy sources would also be taken care of. The transmission system required for open access would also be taken into account in accordance with National Electricity Policy so that congestion in system operation is minimized.
- (b) The STU shall carry out planning process from time to time as per the requirement for identification of intra-State transmission system including transmission system associated with Generation Projects, strengthening of intra-State transmission system to absorb / evacuate power from the ISTS in

- coordination with CTU to optimize the utilization of the Integrated Transmission network. While planning schemes, the following shall be considered in addition to the data of authenticated nature collected from and in consultation with users by the STU:
- i. Perspective plan formulated by CEA.
  - ii. Electric Power Survey of India published by the CEA.
  - iii. Transmission Planning Criteria and guidelines issued by the CEA.
  - iv. Operational feedback from RPCs.
  - v. Operational feedback from RLDC/SLDC.
  - vi. Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009, amended from time to time.
  - vii. Renewable energy capacity addition plan issued by the Ministry of New and Renewable Energy Sources (MNRES), Govt. of India and the State Agency (KREDL).
  - viii. Feedback from CTU on the LTOA granted to ISGS, IPPs and bulk consumers.
- (c) In addition to the intra-State Transmission system, the STU shall plan, from time to time, system strengthening schemes need of which may arise to overcome the constraints in power transfer and to improve the overall performance of the grid.
- (d) All Users, CTU, In-SGS and Karnataka Renewable Energy Development Limited (KREDL) and Users shall supply to the STU, the desired planning data from time to time to enable them to formulate and finalize its plan.
- (e) As voltage management plays an important role in intra-State transmission of energy, special attention shall be accorded, by STU and Users for adequate compensation for active and reactive power management considering various technological options such as Static VAr Compensators (SVC etc).
- (f) In case Long Term Access Applications require any strengthening in the intra-State transmission system to absorb/evacuate power within the State, the applicant shall coordinate with the STU. STU shall augment the intra-State transmission system in a reasonable time to facilitate absorption / evacuation.
- (g) Based on plans prepared by the CTU, STU shall have to plan their systems to further evacuate power from ISTS and to optimize the use of the integrated Transmission network.

- (h) The inter-State Transmission system and associated intra-State transmission system are complementary and inter dependent and planning of one affects the other's planning and performances. Therefore, the associated intra-State transmission system shall also be discussed and reviewed before implementation during the discussion for finalizing the ISTS proposal.

#### **4.6 Planning Criteria:**

##### **4.6.1 General Philosophy:**

The Central Electricity Authority is responsible for preparation of perspective generation and transmission plans and for coordinating the activities of planning agencies as provided under Section 73(a) of the Electricity Act 2003. The Central Transmission Utility (CTU) is responsible for development of an efficient and coordinated inter-State transmission system (ISTS). Similarly, the State Transmission Utility (STU) is responsible for development of an efficient and coordinated intra-State transmission system (In-STS). The ISTS and In-STS are interconnected and together constitute the electricity grid. It is, therefore, imperative that there should be a uniform approach to transmission planning for developing a reliable National transmission system.

- i. The planning criteria detailed herein are primarily meant for planning of Intra-State Transmission System (In-STS) down to 66kV level, including the dedicated transmission lines.

##### **4.6.2 Applicability**

- a. This planning criteria shall be applicable from the date this Grid Code is published in the Gazette.
- b. This criteria shall be used for all new transmission systems planned after the above date.
- c. The existing and already planned In-STS may be reviewed with respect to the provisions of this planning criteria. Wherever required and possible, additional system shall be planned to strengthen the system to meet the revised criteria. Till implementation of the additional system, suitable defense mechanisms should be put into place.

#### 4.6.3 Planning Philosophy and General Guidelines

- a) The long term applicants seeking transmission service are required to pose their end-to-end requirements well in advance, considering time required for implementation of the transmission project, to the STU so as to make-available the requisite transmission capacity and minimise situations of congestion and stranded assets.
- b) The transmission customers are also required to provide a basis for their transmission requirement such as – size and completion schedule of their generation facility, demand based on EPS and their commitment to bear transmission service charges.
- c) Planning of transmission system for evacuation of power from hydro projects shall be done river basin wise considering the identified generation projects and their power potential.
- d) In case of highly constrained areas like congested urban / semi-urban area, very difficult terrain etc., the transmission corridor may be planned by taking long term perspective of optimizing the right-of-way and cost. This may be done by adopting higher voltage levels for final system and operating one level below in the initial stage, or by using multi-circuit towers for stringing circuits in the future, or using new technology such as HVDC, GIS, GIL (Gas insulated Lines), Monopoles, HV UG cables and HTLS conductors etc.
- e) In accordance with Section 39 of the Electricity Act, the STU shall act as the nodal agency for In-STS planning in coordination with distribution licensees and intra-State generators connected/to be connected in the State grid. The STU shall be the single point contact for the purpose of In-STS planning and shall be responsible on behalf of all the intra-State entities, for evacuation of power from their State's generating stations, meeting requirements of DISCOMs and drawing power from ISTS commensurate with the ISTS Plan.
- f) Normally, the various intra-State entities shall be supplied power through the intra-State network. Only under exceptional circumstances, the load serving intra-State entity may be allowed direct inter-connection with ISTS on recommendation of STU provided that such an entity would continue as intra-State entity for the purpose of all jurisdictional matters including energy accounting. Under such situation, this direct interconnection may also be used by other intra-State entity(s).

- Further, State Transmission Utilities (STUs) shall coordinate with urban planning agencies, Special Economic Zone (SEZ) developers, and industrial developers etc., to keep adequate provision for transmission corridor and land for new substations for their long term requirements.
- g) The system parameters and loading of system elements shall remain within prescribed limits. The adequacy of the transmission system should be tested for different feasible load-generation scenarios as detailed subsequently in this document.
- h) The system shall be planned to operate within permissible limits both under normal as well as after more probable credible contingency as detailed in subsequent paragraphs of this Grid Code. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/rare but credible contingencies should be identified from time to time and suitable defense mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, etc., may be worked out to mitigate their adverse impact.
- i) The planned transmission capacity would be finite and there are bound to be congestions if electricity is sought to be transmitted in quantum and direction not previously planned.
- j) The following options may be considered for planning of the transmission network. The choice shall be based on cost, reliability, right-of way requirements, transmission losses, down time (in case of up-gradation and re-conductoring options) etc.,
- i. Addition of new transmission lines/ substations to avoid overloading of existing system including adoption of next higher voltage.
  - ii. Application of FACTS devices namely, Series Capacitors and phase-shifting transformers in existing and new transmission systems to increase power transfer capability.
  - iii. Up-gradation of the existing AC transmission lines to higher voltage using same right-of-way.
  - iv. Re-conductoring of the existing AC transmission line with higher ampacity conductors.
  - v. Use of multi-voltage level and multi-circuit transmission lines.

- vi. Use of narrow base towers and pole type towers in semi-urban / urban areas keeping in view cost and right-of-way optimization.
  - vii. Use of HVDC transmission – both conventional and voltage source convertor (VSC) based.
  - viii. Use of GIS / Hybrid switchgear (for urban, coastal, polluted areas etc) \use of EHV cables and any other appropriate upcoming technologies.
- k) Critical loads such as - railways, metro rail, airports, refineries, underground mines, steel plants, smelter plants, hospitals etc., shall plan their interconnection with the grid, with 100% redundancy and as far as possible from two different sources of supply, in coordination with the concerned STU.
- l) Appropriate communication system for the new sub-stations and generating stations may be planned by the STU and implemented by licensees as well as generation developers so that the same is ready at the time of commissioning.

#### **4.6.4 Criteria for Steady-state and Transient-state behavior**

##### **i) General principles**

The transmission system shall be planned considering the following general principles:

- a) In normal operation ('N-0') of the grid, with all the elements to be available in service, it is required that all the system parameters like voltages, loadings, frequency should remain within permissible normal limits.
- b) The grid may however be subjected to disturbances and it is required that loss of any one element ('N-1' or single contingency condition), all the system parameters like voltages, loadings, frequency shall be within permissible normal limits.
- c) However, after suffering one contingency, grid is still vulnerable to experience second contingency, though less probable ('N-1-1'), wherein some of the equipment may be loaded up to their emergency limits. To bring the system parameters back within their normal limits, load shedding/re-scheduling of generation may have to be applied either manually or through automatic system protection schemes (SPS). Such measures shall generally be applied within one and a half hour (1½) after the disturbance.



**ii) Permissible normal and emergency limits**

a) Normal thermal ratings and normal voltage limits represent equipment limits that can be sustained on continuous basis. Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time which may be one hour to two hour depending on design of the equipment. The normal and emergency ratings to be used in this context are given below:

(i) The loading limit for a transmission line shall be its thermal loading limit. The thermal loading limit of a line is determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient etc. In India, all the above factors and more particularly ambient temperatures in various parts of the country are different and vary considerably during various seasons of the year.

However, during planning, the ambient temperature and other factors are assumed to be fixed, thereby permitting margins during operation. Generally, the ambient temperature may be taken as 45° Celsius; however, in some places like hilly areas where ambient temperatures are less, the actuals may be taken. The maximum permissible thermal line loadings for different types of line configurations, employing various types of conductors are as per CEA Planning Criteria 2013.

(ii) Design of transmission lines with various types of conductors should be based on conductor temperature limit, right-of-way optimization, losses in the line, cost and reliability considerations etc.

(iii) The loading limit for an inter-connecting transformer (ICT) shall be its name plate rating.

(iv) The emergency thermal limits for the purpose of planning shall be 110% of the normal thermal limits.

**b) Voltage limits**

(i) The steady-state voltage limits are given below. However, at the planning stage a margin as specified at Paragraph: 4.6.5 (II) H (d) may be kept in the voltage limits.

	Voltage( kV rms)			
	Normal rating		Emergency rating	
	Nominal	Maximum	Minimum	Maximum
765	800	728	800	713
400	420	380	420	372
220	245	198	245	194
110	121	99	123	97
66	72.5	60	72.5	59

(ii) Temporary over voltage limits due to sudden load rejection:

- i) 800kV class system 1.4 p.u. peak phase to neutral (653 kV = 1 p.u.)
- ii) 420kV class system 1.5 p.u. peak phase to neutral (343 kV = 1 p.u.)
- iii) 245kV class system 1.8 p.u. peak phase to neutral (200 kV = 1 p.u.)
- iv) 145kV class system 1.8 p.u. peak phase to neutral (118 kV = 1 p.u.)
- v) 123kV class system 1.8 p.u. peak phase to neutral (100 kV = 1 p.u.)
- vi) 72.5kV class system 1.9 p.u. peak phase to neutral (59 kV = 1 p.u.)

(iii) Switching over voltage limits

- i) 800kV class system 1.9 p.u. peak phase to neutral (653 kV = 1 p.u.)
- ii) 420kV class system 2.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

### c) Reliability criteria

- (i) Criteria for system with no contingency ('N-0') the system shall be tested for all the load-generation scenarios as given in this document at Paragraph: 4.6.5 (II) D to F.
- (ii) For the planning purpose all the equipment shall remain within their normal thermal loadings and voltage ratings.
- (iii) The angular separation between adjacent nodes or substations (buses) shall not exceed 30 degree.

**d) Criteria for single contingency ('N-1')**

**1) Steady-state:**

- (a) All the equipment in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following elements (called single contingency or 'N-1' condition), but without load shedding / rescheduling of generation:

- Outage of a 110 kV or 66 kV single circuit,
- Outage of a 220kV or 230kV single circuit,
- Outage of a 400kV single circuit,
- Outage of a 400kV single circuit with fixed series capacitor (FSC),
- Outage of an Inter-Connecting Transformer (ICT),
- Outage of a 765kV single circuit,
- Outage of one pole of HVDC bipole.

- (b) The angular separation between adjacent buses under ('N-1') conditions shall not exceed 30 degree.

**2) Transient-state:**

Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. The transmission system shall be stable after it is subjected to one of the following disturbances:

- (a) The system shall be able to survive a permanent three phase to ground fault on a 765kV line close to the bus to be cleared in 100 milliseconds.
- (b) The system shall be able to survive a permanent single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

- (c) The system shall be able to survive a permanent three phase to ground fault on a 400kV line close to the bus to be cleared in 100 ms.
- (d) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.
- (e) In case of 220kV / 110 / 66kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 100 ms (5 cycles) assuming 3-pole opening.
- (f) The system shall be able to survive a fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC Bipole.
- (g) Contingency of loss of generation: The system shall remain stable under the contingency of outage of single largest generating unit or a critical generating unit (choice of candidate critical generating unit is left to the transmission planner).

### **3) Criteria for second contingency ('N-1-1')**

Under the scenario where a contingency as defined at Paragraph: 4.6.4 (v)i(a) has already happened, the system may be subjected to one of the following subsequent contingencies (called 'N-1-1' condition):

- (a) The system shall be able to survive a temporary single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and successful re-closure (dead time 1 second) shall be considered.
- (b) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

- (c) In case of 220kV / 110 /66 kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 100 (5 cycles) assuming 3-pole opening.
- (d) In the 'N-1-1' contingency condition as stated above, if there is a temporary fault, the system shall not lose the second element after clearing of fault but shall successfully survive the disturbance.
- (e) In case of permanent fault, the system shall lose the second element as a result of fault clearing and thereafter, shall asymptotically reach to a new steady state without losing synchronism. In this new state the system parameters (i.e. voltages and line loadings) shall not exceed emergency limits, however, there may be requirement of load shedding/rescheduling of generation so as to bring system parameters within normal limits.

#### **4) Criteria for generation radially connected with the grid**

For the transmission system connecting generators or a group of generators radially with the grid, the following criteria shall apply:

- (a) The radial system shall meet 'N-1' reliability criteria as given at Paragraph: 4.6.4(iv) 1) & 2) for both the steady-state as well as transient-state.
- (b) For subsequent contingency i.e., 'N-1-1' (of Paragraph: 4.6.4 (IV) 3) only temporary fault shall be considered for the radial system.
- (c) If the 'N-1-1' contingency is of permanent nature or any disturbance/contingency causes disconnection of such generator/group of generators from the main grid, the remaining main grid shall asymptotically reach to a new steady-state without losing synchronism after loss of generation. In this new state the system parameters shall not exceed emergency limits, however, there may be requirement of load shedding / rescheduling of generation so as to bring system parameters within normal limits.

#### 4.6.5 Criteria for simulation and studies

##### I. System studies for transmission planning

- a) The system shall be planned based on one or more of the following power system studies, as per requirements:
- i. Power Flow Studies
  - ii. Short Circuit Studies
  - iii. Stability Studies (including transient stability \*\* and voltage stability)
  - iv. EMTP studies (for switching / dynamic over-voltages, insulation coordination, etc)

*(\*\* Note: The candidate lines, for which stability studies may be carried out, may be selected through results of load flow studies. Choice of candidate lines for transient stability studies are left to transmission planner. Generally, the lines for which the angular difference between its terminal buses is more than 20 degree after contingency of one circuit may be selected for performing stability studies.)*

##### II. Power system model for simulation studies

###### A. Consideration of voltage level

For the purpose of planning of the Intra-STC System, the transmission network may be modeled down to 66kV level or up to the voltage level which is not in the jurisdiction of DISCOM. The STUs may also consider modeling smaller generating units (below 50MW capacity) if required.

###### B. Time Horizons for transmission planning

- i. From concept to commissioning of transmission elements generally takes three to five years; about three years for augmentation of capacitors, reactors, transformers etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon.
- ii. Endeavour shall be to prepare base case models corresponding to load generation scenarios for a 5 year time horizon. These models may be tested applying the relevant criteria mentioned in this manual.

**C. Load - generation scenarios**

- i. The load-generation scenarios shall be worked out so as to reflect in a pragmatic manner the typical daily and seasonal variations in load demand and generation availability.

**D. Load demands****i) Active power (MW)**

- a) The system peak demands (State-wise, regional and national) shall be based on the latest Electric Power Survey (EPS) report of CEA. However, the same may be moderated based on actual load growth of past three (3) years.
- b) The load demands at other periods (seasonal variations and minimum loads) shall be derived based on the annual peak demand and past pattern of load variations. In the absence of such data, the season-wise variation in the load demand may be taken as given below:

SI No	Season/ Scenario	Region-wise Demand Factors (%)				
		NR	WR	SR	ER	NER
1	Summer peak Load (S-PL)	100	95	98	100	100
2	Summer Light Load (S-LL)	70	70	70	70	70
3	Monsoon peak Load (M-LL)	96	90	90	95	95
4	Monsoon Light Load (M-LL)	70	70	70	70	70
5	Winter Peak Load (W-PL)	95	100	100	95	95
6	Winter Peak Load (W-LL)	70	70	70	70	70

- c) While doing the simulation, if the peak load figures are more than the peaking availability of generation, the loads may be suitably adjusted substation-wise to match with the availability. Similarly, while doing the simulation, if the peaking availability is more than the peak load, the generation despatches may be suitably reduced, to the extent possible, such that, the inter-regional power transfers are high.
- d) From practical considerations the load variations over the year shall be considered as under:

- i. Annual Peak Load

- ii. Seasonal variation in Peak Loads for Winter, Summer and Monsoon
  - iii. Seasonal Light Load (for Light Load scenario, motor load of pumped storage plants shall be considered)
- e) The sub-station wise annual load data, both MW and MVAR shall be provided by the DISCOMS.

**ii) Reactive power (MVAR)**

- a) 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 the different substations as well as the projected plans for reactive power compensation.
- b) For developing optimal In-STS, the DISCOMs must clearly spell out the substation-wise maximum and minimum demand in MW and MVAR on seasonal basis. In the absence of such data the load power factor at 110kV and 66kV voltage levels may be taken as 0.95 lag during peak load condition and 0.98 lag during light load condition. The DISCOMS shall provide adequate reactive compensation at the feeder level to bring power factor close to unity at 110kV and 66kV voltage levels.

**E. Generation Despatches and modeling**

- a) For planning of new transmission lines and substations, the peak load scenarios corresponding to summer, monsoon and winter seasons may be studied. Further, the light load scenarios (considering pumping load where pumped storage stations exist) may also be carried out as per requirement.
- b) For evolving transmission systems for integration of wind and solar generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional Despatch scenarios. In such scenarios, the Intra-State generating station of the RES purchasing State may be backed-down so that impact of wind generation on the ISTS grid is minimum. The maximum generation at a wind/solar aggregation level may be calculated using capacity factors as per the norms given in Table below:



<b>Voltage level /Aggregation level</b>	<b>110kV / Individual Solar farm</b>	<b>66kV / wind/</b>	<b>220kV</b>	<b>400kV</b>	<b>State as a Whole</b>
Capacity Factor (%)	80%		75%	70%	60%

- c) As per this Grid Code, it is the responsibility of each SLDC to balance its load and generation and stick to the schedules. Accordingly, it follows that in case of variation in generation from Renewable Energy Source (RES) portfolio, the State should backdown/ ramp-up its conventional (thermal/hydro) generation plants or revise their drawal schedule from ISGS plants and stick to the revised schedule. The Intra-State generating station should be capable of ramping-up/backing-down based on variation in RES generation, so that the impact of variability in RES on the ISTS grid is minimum.
- d) Further to address the variability of the wind/solar projects, other aspects like reactive compensation, forecasting and establishment of renewable energy control centers may also be planned by SLDC/STUs.

#### **F. Special area Despaches:**

- a. Special Despaches corresponding to high agricultural load with low power factor, wherever applicable.
- b. Complete closure of a generating station close to a major load centre.
- c. In case of thermal units (including coal, gas/diesel and nuclear based) the minimum level of output (ex-generation bus, i.e., net of the auxiliary consumption) shall be taken as not less than 70% of the rated installed capacity. If the thermal units are encouraged to run with oil support, they may be modeled to run up to 25% of the rated capacity.
- d. It shall be the duty of all the generators to provide technical details such as machine capability curves, generator, exciter, governor, PSS parameters etc., for modeling of their machines for steady-state and transient-state studies, in the format sought by STU.

### **G. Short circuit studies**

- a) The short circuit studies shall be carried out using the classical method with flat pre-fault voltages and sub-transient reactance ( $X''_d$ ) of the synchronous machines.
- b) MVA of all the generating units in a plant may be considered for determining maximum short-circuit level at various buses in system. This short-circuit level may be considered for substation planning.
- c) Vector group of the transformers shall be considered for doing short circuit studies for asymmetrical faults. Inter-winding reactances in case of three winding transformers shall also be considered. For evaluating the short circuit levels at a generating bus (11kV, 13.8 kV, 21kV etc.), the unit and its generator transformer shall be represented separately.
- d) Short circuit level both for three phase to ground fault and single phase to ground fault shall be calculated.
- e) The short-circuit level in the system varies with operating conditions, it may be low for light load scenario compared with for peak load scenario, as some of the plants may not be on-bar. For getting an understanding of system strength under different load-generation / export-import scenarios, the MVA of only those machines shall be taken which are on bar in that scenario.

### **H. Planning margins**

- a) In a very large interconnected grid, there can be unpredictable power flows in real time due to imbalance in load-generation balance in different pockets of the grid. This may lead to overloading of transmission elements during operation, which cannot be predicted in advance at the planning stage. This can also happen due to delay in commissioning of a few planned transmission elements, delay/ abandoning of planned generation additions or load growth at variance with the estimates. Such uncertainties are unavoidable and hence some margins at the planning stage may help in reducing impact of such uncertainties. However, care needs to be taken to avoid stranded transmission assets. Therefore, at the planning stage following planning margins may be provided:

- b) Against the requirement of Long Term Access sought, the new transmission lines emanating from a power station to the nearest grid point may be planned considering overload capacity of the generating stations in consultation with generators.
- c) The new transmission additions required for system strengthening may be planned keeping a margin of 10% in the thermal loading limits of lines and transformers (refer Paragraph: 4.6.4 (ii) above).
- d) At the planning stage, a margin of about + 2% may be kept in the voltage limits (as given at Paragraph: 4.6.4 (ii)(f), above) and thus the voltages under load flow studies (for 'N-0' and 'N-1' steady-state conditions only) may be maintained within the limits given below:

**Voltage (kVrms) (after planning margins)**

Nominal	Maximum	Minimum
765	785	745
400	412	388
220	240	203
110	119	102
66	70	62

- e) In planning studies all the transformers may be kept at nominal taps and on Load Tap Changer (OLTC) may not be considered. The effect of the taps should be kept as operational margin.
- f) For the purpose of load flow studies at planning stage, the nuclear generating units shall normally not run at leading power factor. To keep some margin at planning stage, the reactive power limits ( $Q_{max}$  and  $Q_{min}$ ) for generator buses may be taken as:

Type of generating unit	$Q_{max}$	$Q_{min}$
Nuclear units	$Q_{max} = 0.50 \times P_{max}$	$Q_{min} = (-)0.10 \times P_{max}$
Thermal Units (other than Nuclear)	$Q_{max} = 0.50 \times P_{max}$	$Q_{min} = (-)0.10 \times P_{max}$

Hydro units	$Q_{max} = 0.40 \times P_{max}$	$Q_{min} = (-)0.20 \times P_{max}$
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Notwithstanding above, during operation, following the instructions of the System Operator, the generating units shall operate at leading power factor as per their respective capability curves.

#### 4.6.6 Additional planning criteria and guidelines

##### i. Reactive power compensation

a) 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 by appropriate studies.

b) Shunt capacitors

(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.

(2) It shall be the responsibility of the respective distribution licensees 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 220/110(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.

c) **Shunt reactors**

(1) Switchable bus reactors shall be provided at EHV substations for controlling voltages within the limits (defined in the Paragraph: 4.6.4(ii)(f) without resorting to switching-off of lines. The bus reactors may also be provided at generation switchyards to supplement 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%. The standard sizes (MVAR) of reactors are:

<b>Voltage Level</b>	<b>Standard sizes of reactors ( in MVar)</b>
400kV ( 3-ph units)	50, 63, 80 and 125 (rated at 420kV)
765kV ( 1-ph units)	80 and 110 (rated at 800kV)

Fixed line reactors may be provided to control power frequency temporary over-voltage (TOV) after all voltage regulation action has taken place within the limits as defined in Paragraph: 4.6.4 (ii)(g) under all probable operating conditions.

- (2) Line reactors (switchable/ controlled/ fixed) may be provided if it is not possible to charge EHV line without exceeding the maximum voltage limits given in Paragraph: 4.6.4 (ii)(f). The possibility of reducing pre-charging voltage of the charging end shall also be considered in the context of establishing the need for reactors.
- (3) Guideline for switchable line reactors: The line reactors may be planned as switchable wherever the voltage limits, without the reactor(s), remain within limits specified for TOV conditions given at Paragraph: 4.6.4 (ii)(g).

#### d) **Static VAr compensation (SVC)**

Static VAr Compensation (SVC) shall be provided where found necessary to damp the power swings and provide the system stability under conditions defined in the Paragraph: 4.6.4(iii) on 'Reliability Criteria'. The dynamic range of static compensators shall not be utilized under steady state operating condition as far as possible.

#### **4.6.7 Substation planning criteria**

- (1) The requirements in respect of EHV sub-stations in a system such as the total load to be catered by the sub-station of a particular voltage level, its MVA capacity, number of feeders permissible etc., are important to the planners so as to provide an idea to them about the time for going in for the adoption of next higher voltage level sub-station and also the number of substations required for meeting a particular quantum of load. Keeping these in view the following criteria have been laid down for planning an EHV substation:
  - (2) The maximum short-circuit level on any new substation bus should not exceed 80% of the rated short circuit capacity of the substation. The 20% margin is intended to take care of the increase in short-circuit levels as the system grows.

The rated breaking current capability of switchgear at different voltage levels may be taken as given below:

<b>Voltage Level</b>	<b>Rated Breaking capacity</b>
66 kV	25kA/31.5kA
110 kV	25kA/31.5kA
220 kV	31.5 kA/40kA
400 kV	50kA/63kA
765 kV	40kA/50kA

Measures such as splitting of bus, series reactor, or any new technology may also be adopted to limit the short circuit levels at existing substations wherever they are likely to cross the designed limits **without sacrificing the operational flexibility and grid security**.

- (3) Rating of the various substation equipments shall be such that they do not limit the loading limits of connected transmission lines.
- (4) Effort should be to explore possibility of planning a new substation instead of adding transformer capacity at an existing substation when the capacity of the existing sub-station has reached levels as given in column (B) in the following table. The capacity of any single sub-station at different voltage levels shall not normally exceed as given in column (C) in the following table:

<b>Voltage Level (A)</b>	<b>Transformer Capacity</b>	
	<b>Existing capacity (B)</b>	<b>Maximum Capacity (C)</b>
765 kV	6000 MVA	9000 MVA
400 kV	1260 MVA	2000 MVA
220 kV	320 MVA	500 MVA
110 kV	150 MVA	250 MVA
66kV	85 MVA	120 MVA

- (5) While augmenting the transformation capacity at an existing substation or planning a new substation the fault level of the substation shall also be kept in view. If the fault level is low the voltage stability studies shall be carried out.

- (6) Size and number of interconnecting transformers (ICTs) shall be planned in such a way that the outage of any single unit would not overload the remaining ICT(s) or the underlying system.
- (7) A stuck breaker condition shall not cause disruption of more than four feeders for the 220kV system and two feeders for the 400kV system and 765kV system.

**Note** – In order to meet this requirement it is recommended that the following bus switching scheme may be adopted for both AIS and GIS and also for the generation switchyards:

- 220kV – ‘Double Main’ or ‘Double Main & Transfer’ scheme with a maximum of eight (8) feeders in one section
- 400kV and 765kV – ‘One and half breaker’ scheme

#### 4.6.8 Additional criteria for wind and solar projects

- (1) The capacity factor for the purpose of maximum injection to plan the evacuation system, both for immediate connectivity with the In-STS and for onward transmission requirement, may be taken as given below:

Voltage level/ Aggregation level	110kV/66kV /Individual wind /Solar farm	220kV	400kV	State as a whole
Capacity Factor (%)	80%	75%	70%	60%

- (2) The ‘N-1’ criteria may not be applied to the immediate connectivity of wind/solar farms with the In-STS grid i.e., the line connecting the farm to the grid and the step-up transformers at the grid station.
- (3) The wind generating stations connected at voltage level of 66kV and above shall remain connected to the grid when the voltage at the interconnection point or any or all phases dips a level of 85% of the nominal voltage (i.e., the wind generators should be capable to have low voltage ride through facility).
- (4) As the generation of energy at a wind farm is possible only with the prevalence of wind, the thermal line loading limit of the lines connecting the wind machine(s)/farm to the nearest grid point may be assessed considering 12 km/hour wind speed.

- (5) The wind and solar farms shall maintain a power factor of 0.98 (absorbing) at their grid inter-connection point for all Despatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies.
- (6) The Harmonic current injection from a generating station shall not exceed the limits specified in IEEE standard 519.

#### **4.6.9 Guidelines for Planning HVDC Transmission System**

- (1) The option of HVDC bipole may be considered for transmitting bulk power over long distance based on techno economic criteria. HVDC transmission may also be considered in the transmission corridors that have AC lines carrying heavy power flows (total more than 5000 MW) to control and supplement the AC transmission network.
- (2) The ratio of fault level in MVA at any of the converter station (for conventional current source type), to the power flow on the HVDC bipole shall not be less than 3.0 under any of the load-generation scenarios given under Paragraph:4.6.5 (ii) (C) to (F) and contingencies given at Paragraph: 4.6.4(iv), above.

Further, in areas where multiple HVDC bipoles are feeding power (multi in feed), the appropriate studies be carried at planning stage so as to avoid commutation failure.

#### **4.6.10 Guidelines for voltage stability**

- (1) Voltage Stability Studies: These studies may be carried out using load flow analysis to arrive at the knee point of Q-V curve which represents the horizontal 'distance' of the knee point to the zero-MVAR vertical axis measured in MVAR is, therefore, an indicator of the proximity to the voltage collapse.
- (2) Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions as discussed above. The system shall have adequate margins in terms of voltage stability.

#### **4.7 Planning Data**

Under this Planning Code, the State Generating Companies / IPPs / licensees are to supply data in accordance with the detailed procedures mentioned in the Karnataka Electricity Regulatory Commission (Terms and conditions for Open Access) Regulations, 2004 as amended from time to time.



## SECTION- 5

### GRID CONNECTIVITY

#### 5.1 Introduction

All Users connected to, or seeking connection to In-STS shall comply with Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 which specifies the minimum technical and design criteria and Karnataka Electricity Regulatory Commission (Terms and Conditions for Open Access) Regulations, 2004 as amended from time to time.

#### 5.2 Objective

The objective of the Grid Connectivity is as given below:

- a) To ensure the safe operation, integrity and reliability of the grid.
- b) That the basic rules for connectivity are complied with in order 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 In-STS nor impose unacceptable effects on the system of any other connected User or Transmission Licensee and Distribution Licensees.
- d) To make aware in advance the procedures for connectivity to In-STS and also the standards and condition of the system to be integrated to the grid to any person seeking a new connectivity to the grid.

#### 5.3 Scope

The connectivity criteria is applicable to all Users connected to or seeking connection to the InSTS, All such entities shall abide by the CEA (Technical Standards for connectivity to the Grid) Regulations, 2007, in order to ensure that the integrated grid is not adversely affected.

#### 5.4 Procedure for connection

A User seeking to establish new or modified arrangement of connection to or for use of In-STS, shall submit an application in the standard format (prepared by STU and approved by KEREC) to STU in case the connection is sought to intra-State transmission system and respective ESCOM in case the connection is sought at distribution system.

The STU shall process the application for grant of connectivity in accordance with these regulations

## 5.5 Connection Agreement

1. A connection agreement, or the offer for a connection agreement shall include (but not limited) within its terms and conditions the following:
  - (i) A condition requiring both Agencies to comply with the Grid Code.
  - (ii) Details of connection technical requirements and commercial arrangements
  - (iii) Details of any capital related payments arising from necessary reinforcement or extension of the system, data communication, RTU etc., and demarcation of the same between the concerned parties.
  - (iv) A Site Responsibility Schedule (Annexure-I).
  - (v) General Philosophy, Guidelines etc on protection and telemetry.
  - (vi) Requirement with respect to Harmonics, Direct current (DC) injection and Flicker (as per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007, amended from time to time).

The Connection agreement with above terms and conditions shall be signed by the applicant not-inconsistent with CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007, amended from time to time and the Karnataka Electricity Regulatory Commission (Terms and conditions for Open Access) Regulations, 2004 as amended from time to time.

### 2. Model connection agreement:

- (i) The standard connection agreement shall be prepared by the STU and submitted to the Commission for approval, within a month from the date of publishing of Grid Code in the official Gazette of Karnataka.
- (ii) The approved format shall be made available for the prospective users of the Grid and shall be hosted on STU's website.

## 5.6 Site responsibility schedule

1. For every connection to the State Transmission System for which a connection agreement is required, STU shall prepare a schedule of equipment with information supplied by the respective Users. This schedule, called 'Site Responsibility Schedule' shall indicate the following for each item of equipment installed at the connection site.

- i. Ownership of the equipment
  - ii. Responsibility for control of equipment
  - iii. Responsibility for maintenance of equipment
  - iv. Responsibility for operation of equipment
  - v. Responsibility for all matters relating to safety of persons and site.
  - vi. Management of the site.
2. The format to be used in the preparation of Site Responsibility Schedule is given in Annexure-I

## **5.7 System Performance**

1. All equipment connected to the State Transmission System shall be of such design and construction that enable STU to meet the requirement of standards of performance to meet the grid standard.
2. Installation of all electrical equipment shall comply with Rules which are in force for the time being and will be replaced by new Rules made under the Electricity Act, 2003.
3. For every new / modified connection sought, the STU shall specify the connection point, technical requirements and the voltage to be used, along with metering, tele-metering and protection requirements as specified in the Metering Code and Protection Code.
4. Insulation coordination of the User's equipment shall conform to the applicable values as specified by STU from time to time out of those applicable as per Indian Standards / Code of Practices. Rupturing capacity of the switchgear shall not be less than that specified by STU from time to time.
5. Protection schemes and metering schemes shall be as detailed in the Protection Code and Metering Code.

## **5.8 State Grid Connection Points / Interface points**

### **1. State Generating Stations (SGS)**

- (i) Voltage may be 400/220/110/66/33 kV or as agreed with STU.
- (ii) Unless specifically agreed with STU, the Connection Point with generating station shall be the terminal isolator provided just before the outgoing gantry of the feeders/evacuation lines.
- (iii) SGS shall operate and maintain all terminals, communication and protection equipment provided within the generating station.
- (iv) The provisions for the metering between generating station and STU system shall be as per the Metering Code.

- (v) Respective Users shall maintain their equipment from the outgoing feeders' gantry onwards emanating from generating station.
- (vi) All entities embedded within the State Grid system and interfacing the intra-State transmission system shall provide adequate and reliable communication facility so that SLDC is able to record in its SCADA system the MW/ MVAR flows, bus voltages at all the interface points with the intra-State system.

## 2. Distribution Licensee

- (i) Voltage may be LV side of power transformer i.e., 33 kV or 11 kV or as agreed with STU. For EHV consumers directly connected to transmission system, voltage may be 400kV /220 kV/ 110 kV/66kV.
- (ii) Unless specifically agreed with Distribution Licensee, the Connection Point with STU shall be the terminal isolator provided just before the outgoing gantry of the feeder to Distribution Licensee or individual EHV consumer as the case may be, from STU sub-station

STU shall operate and maintain all terminals, communication and protection equipment provided within its sub-station. The provisions for the metering between STU and Distribution Licensees system shall be as per the Metering Code. Respective Users shall maintain their equipment beyond the outgoing gantry of feeders emanating from STU sub-station onwards.

## 3. Southern Regional Transmission System

The Connection, protection scheme, metering scheme and the voltage shall be in accordance with the provisions of IEGC.

## 4. Independent Power Producers (IPPs), Captive Power Plants (CPPs), Extra High Voltage (EHV) Consumers and Open Access Consumers.

- (i) Voltage may be 400/220/110/66 kV or as agreed with STU.
- (ii) When IPPs, CPPs, EHV Consumers or the Open Access Consumers own sub-stations, the Connection Point shall be the terminal isolator provided just before the gantry of outgoing/incoming feeder in their premises.

## 5.9 Important Technical Requirements for Connectivity to the Grid

### 5.9.1 Reactive Power Compensation

- a) Reactive Power compensation and/or other facilities shall be provided by Users connected to In-STS avoiding the need for exchange of reactive power to/from In-STS and to maintain In-STS voltage within the specified range.
- b) The person already connected to the grid shall also provide additional reactive compensation as per the quantum and time frame decided by

SLDC. The Users / Transmission Licensees / Distribution Licensees shall provide information to SLDC regarding the installation and healthiness of the reactive compensation equipment on regular basis. SLDC shall regularly monitor the status in this regard.

### **5.9.2 Data and Communication Facilities**

Reliable and efficient communication systems (for speech, data and protection requirements) shall be provided to facilitate necessary information exchange, by all Users, and the STU for supervision/control/protection of the grid by the SLDC, under normal and abnormal conditions. All Users shall provide Systems to telemeter power system parameters such as flow (active and reactive power), voltage and status of switches/ transformer taps etc., in line with interface requirements and other guidelines made available to users by SLDC. The associated communication system and other required facilities at their respective end to facilitate data flow up to appropriate data collection point on STU's system shall also be established by the concerned User, Transmission Licensee / Distribution Licensees as specified by the STU in the Connection Agreement.

### **5.9.3 System Recording Instruments**

Recording instruments such as Data Acquisition System, Disturbance Recorder, Event Logging Facilities, Fault Locator etc., shall be provided and shall always be kept in working condition in the In-STG for recording of dynamic performance of the system.

All disturbance recording and event logging facilities and the numerical relays shall be provided with time synchronization facility for global common time reference.

### **5.9.4 Responsibilities for safety**

STU and all users shall be responsible for safety in accordance with the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007, the Karnataka Electricity Regulatory Commission (the terms and Condition for Open Access) Regulations, 2004, as amended from time to time and CEA (Technical Standards for Construction of Electric plants and Electric Lines) Regulations 2010 and Measures Relating to Safety and Electric Supply) Regulations, 2010.

### **5.9.5 Cyber Security**

All Users and STU shall have in place, a cyber security framework as specified in Information Technology Act, 2000 amended from time to time to identify the critical cyber assets and protect them so as to support reliable operation of the Grid.

### **5.10 Schedule of assets of the State Grid**

STU, other transmission licensees granted licence by the Commission and Generators shall maintain the schedule of their assets and host the same in their respective websites. The same shall be submitted to the Commission as and when called for.

## SECTION -6

### OPERATION PLANNING

#### 6.0 Operating Criteria

This Part describes the operational philosophy to maintain efficient, secure and reliable Grid and contains the following sections.

- (a) Operating Philosophy
- (b) System Security Aspects

This section describes the general security aspects to be followed by generating companies, STU, intra-State transmission licensee, bulk consumers and all other Users of the In-STS.

#### 6.1 Operating philosophy.

- (a) All users connected with In-STS shall comply with this Operating Criteria and the directions issued by SLDC, to ensure integrated grid operation and for achieving the maximum economy and efficiency in the operation of the power system.
- (b) A set of detailed operating procedures for the State Grid shall be developed and maintained by the SLDC in consultation with the concerned persons for guidance of the staff of SLDC and the same shall be consistent with this Grid Code and IEGC to facilitate compliance with the requirement of the Grid Code and IEGC.
- (c) The control rooms of the SLDC, ALDCs / power plants and any other control centres of all Transmission and Distribution Companies shall be manned round the clock by qualified and adequately trained and certified personnel.

#### 6.2 System Security Aspects

- i. STU and all Users shall endeavor to operate their respective power systems and power stations in an integrated manner at all times.
- ii. No part of the grid shall be deliberately isolated from the rest of the State / Regional grid, except

- a) under an emergency, and conditions in which such isolation would prevent a total grid collapse and / or would enable early restoration of power supply,
- b) for safety of human life,
- c) when serious damage to a costly equipment is imminent and such isolation would prevent it,
- d) When such isolation is specifically instructed by SLDC /ALDC.

*Complete synchronization of the grid shall be restored as soon as the conditions again permit it. The restoration process shall be supervised by SLDC, in co-ordination with RLDC.*

- iii. A list of important elements of the State grid which shall not be deliberately opened or removed from service at any time, except when specifically instructed by SLDC or with specific and prior clearance of SLDC (List of such important grid elements on which the above stipulations apply will be prepared by the SLDC in consultation with the RLDC, CTU and STUs as per provisions of Indian Electricity Grid Code) shall be available on the website of SLDC. In case of opening/removal of any important element of the grid under an emergency situation, the same shall be communicated to SLDC at the earliest possible time after the event.
- iv. Any tripping, whether manual or automatic, of any of the above elements of State grid shall be precisely intimated to the SLDC within ten minutes of the event. The reason (to the extent determined) and the likely time of restoration shall also be intimated. All reasonable attempts shall be made for the elements' restoration as soon as possible.
- v. Maintenance of their respective power system elements shall be carried out by users, and STU in accordance with the provisions in the Central Electricity Authority (Grid Standards) Regulations, 2010.  
Any prolonged outage of 400kV and above power system elements, which forms the National Transmission Grid, is causing or likely to cause danger to the grid or sub-optimal operation of the grid, shall be regularly monitored by SLDC. SLDC shall report such outages to RLDC for onward transmission to RPC. STU and Transmission licensee shall make all reasonable efforts to restore such elements as per action plan to be finalized and intimated by RPC as per provisions of IEGC.



The Planned /Scheduled outages of the power system elements pertaining to the State grid shall be carried out by STU in concurrence with the SLDC duly informing the RLDC for secured operation of the Grid.

vi. **Governor Action**

(i) Governor action for all Generators of different capacity, thermal, hydro, gas and renewable generating units shall be operated as per the provisions of IEGC.

- a) Thermal generating units of 200 MW and above
- b) Hydro units of 10 MW and above

(ii) The Restricted Governor Mode of Operation (RGMO) shall essentially have the following features:

(a) There should not be any reduction in generation in case of improvement in grid frequency below the upper limit fixed by CERC from time to time (for example if grid frequency changes from 49.8 to 49.95 Hz. then there shall not be any reduction in generation). Whereas for any fall in grid frequency, generation from the unit should increase by 5% limited to 105 % of the Maximum Continuous Rating (MCR) of the unit subject to machine capability.

(b) Ripple filter of +/- 0.03 Hz. shall be provided so that small changes in frequency are ignored for load correction, in order to prevent governor hunting.

(c) If any of these generating units is required to be operated without its governor in operation as specified above, the RLDC shall be immediately advised about the reason and duration of such operation. All governors shall have a droop setting between 3% and 6%.

(iii) All other generating units including those with pondage upto 3 hours, Gas turbine / Combined Cycle Power Plants, wind and solar generators shall be exempted from clause 6.2 vi and following clauses vii, viii and ix till the situation is reviewed. Provided that if a generating unit cannot be operated under restricted governor mode operation, then it shall be operated in free governor mode operation with manual intervention to

operate in the manner required under restricted governor mode operation

- vii. Facilities available with/in load limiters, Automatic Turbine Run-up System (ATRS), Turbine Supervisory Control, Coordinated Control System, etc., shall not be used to suppress the normal governor action in any manner and no dead bands and/or time delays shall be deliberately introduced except as specified in para 6.2(vi) above.
- viii. All thermal generating units of 200 MW and above and all hydro units of 10 MW and above operating at or up to 100% of their Maximum Continuous Rating shall normally be capable of (and shall not in any way be prevented from) instantaneously picking up to 105% and 110% of their MCR, respectively, when frequency falls suddenly. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements shall be kept in operation (synchronized with the Regional grid) only after obtaining the permission of SLDC / RLDC. The SLDC can also direct a generator to come to its technical minimum in line with CEA/CERC Notifications from time to time depending on the grid situation.
- ix. The recommended rate for changing the governor setting, i.e., supplementary control for increasing or decreasing the output (generation level) for all generating units, irrespective of their type and size, would be one (1.0) per cent per minute or as per manufacturer's limits. However, if frequency falls below the limit specified by CERC from time to time, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability. All generators shall inform the SLDC on the Governor status as and when required and also submit the performance analysis of RGMO to SLDC for verification.
- x. Except under an emergency, or to prevent an imminent damage to costly equipment, no Generator shall suddenly reduce his generating unit output without prior intimation to and consent of the SLDC, particularly when frequency is falling or is below the limit specified by CERC from time to time. Similarly, no User / Distribution Licensee shall cause a sudden variation in its load without prior intimation to and consent of the SLDC. The extent of sudden reduction in Generator output / sudden variation of load by User / Distribution

- Licensee shall be determined by SLDC. In the event of any inconsistency in this provision from that of the IEGC, the provisions of IEGC shall prevail.
- xi. All users shall ensure that temporary over voltage due to sudden load rejection and the maximum permissible values of voltage unbalance shall remain within limits specified under the Central Electricity Authority (Grid Standards) Regulations, 2010.
  - xii. All generating units shall normally have their automatic voltage regulators (AVRs) in operation. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the SLDC shall be immediately intimated about the reason and duration of such operation, and obtain its permission. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be properly tuned by the respective generating unit owner duly reporting the AVR and PSS functional availability to SLDC and SLDC shall undertake to do random test to ascertain the functionality of AVR and PSS.
  - xiii. Provision of protections and relay settings shall be coordinated periodically throughout the Regional grid, as per a plan to be separately finalized by the Protection Sub-Committee of the SRPC. SRPC will prepare islanding schemes and ensure its implementation in accordance with the Central Electricity Authority (Grid Standards) Regulations, 2010. All Users shall ensure that installation and operation of protection system shall comply with the provisions of the Central Electricity Authority (Grid Standards) Regulations, 2010.
  - xiv. SLDC shall ensure that all Users take all possible measures to ensure that the grid frequency always remains within the frequency band specified by the CERC from time to time.
  - xv. All distribution licensees and STU shall provide automatic under-frequency and df/dt relays for load shedding in their respective systems, to arrest frequency decline that could result in a collapse/disintegration of the grid, as per the plan separately finalized by the concerned RPC and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency. All distribution licensees, STU and SLDC shall ensure that the above under-frequency and df/dt load shedding / islanding schemes are always functional. The provisions of the CEA Regulations regarding under frequency and df/dt relays shall be complied with. All Distribution licensees and STU shall abide by the decisions of SRPC regarding action to be taken to

get the required load relief from under frequency and df/dt relays by STU or SLDC. **The required relief available at the set (under) frequency shall be monitored on a continuous basis by SLDC.**

- xvi. All Users, STU/SLDC shall also facilitate identification, installation and commissioning of System Protection Schemes (SPS) (including inter-tripping and run-back) finalized by the SRPC Forum in the power system to operate the transmission system closer to their limits and to protect against situations such as voltage collapse and cascade tripping, tripping of important corridors/flow-gates etc., Such schemes finalized by the concerned SRPC forum shall always be kept in service. Any SPS is to be taken out of service; only with consultation with RLDC after indicating reason and duration of anticipated outage from service.
- xvii. Procedures shall be developed and documented for recovery from partial/total collapse of the grid in accordance with the Central Electricity Authority (Grid Standards) Regulations, 2010 and to periodically update the same in accordance with their requirements given under Regulation 14. These procedures shall be followed by all the Users and STU/SLDC to ensure consistent, reliable and quick restoration.
- xviii. Each User, distribution licensee, STU and SLDC shall provide and maintain adequate and reliable communication facility with redundancy internally and with other Users / STU / ALDCs / SLDC to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes, e.g., ALDC to SLDC.
- xix. All the Users, Distribution licensees / ALDCs / STU shall send information / data including disturbance recorder/sequential event recorder output to SLDC within 24 Hours for purpose of analysis of any grid disturbance/event. No User / distribution licensee / ALDCs / SLDC / STU shall block any data / information required by the SLDC and SRPC/SRLDC for maintaining reliability and security of the grid and for analysis of an event.
- xx. All Users, Distribution licensees and STU shall provide adequate voltage control measures through automatic under voltage relays as finalized in consultation with SRPC, to prevent voltage collapse and shall ensure its effective application to prevent voltage collapse/ cascade tripping Voltage fluctuation limits and voltage wave-form quality shall be maintained as

specified in the Central Electricity Authority (Grid Standards) Regulations, 2010, and amendments from time to time.

xxi. Special requirements for Renewable Energy

System Operator (SLDC) shall make all efforts to evacuate the available Solar, mini-hydel, co-generation and wind power and other Renewable Energy (RE) sources and treat the plants as must-run stations. However, SLDC may instruct such generator to back down generation in case grid security or safety of any equipment or personnel is likely to be endangered and Renewable Energy (RE) sources shall comply with the same. For this, Data Acquisition System facility shall be provided by the generator for transfer of information to the SLDC.

- i. SLDC may direct a wind farm to curtail its VAR drawal/injection in case the security of grid or safety of any equipment or personnel is endangered.
- ii. During the wind generator start-up, the wind generator shall ensure that the reactive power drawal (inrush currents in case of induction generators) shall not affect the grid performance.

### **6.3 Demand Estimation for Operational Purpose**

Load forecasting shall be carried as per the KERC (load forecast) Regulations, 2009, and not- inconsistent with the above Regulations the following may be adhered to:

- (a) The distribution licensee shall formulate a long term demand forecast considering the previous financial years as base and projecting the demand for the succeeding 5 years.
- (b) It shall be the responsibility of all distribution licensees to fully co-operate with STU in preparation of demand forecast for the entire State.
- (c) The distribution licensee shall provide their estimates for the period from 1<sup>st</sup> April to 31<sup>st</sup> March by 1<sup>st</sup> January of each year on a 'financial year ahead' basis. This shall be updated for every month subsequently in the previous month on a 'month ahead basis' and in the previous day on a 'day ahead basis' as required by STU/SLDC.
- (d) The long term demand estimation/ load forecast (for more than one year) shall be done by STU and SLDC shall be provided with a copy of the same as and when it is finalized.
- (e) Based on the data furnished by the distribution licensees, STU shall make monthly peak and lean period demand estimates for year ahead and daily

- peak and lean period demand estimates for the month ahead and furnish the same to SLDC.
- (f) The distribution Licensee shall provide SLDC on day ahead basis, at 9.00 Hrs each day their estimated demand for each 15-minute block for the ensuing day. Distribution licensee shall also provide SLDC estimates of loads that may be shed, when required, in discreet blocks with details of arrangements of such load shedding.
  - (g) The SLDC would update demand forecast (in MW as well as KWh) on quarterly, monthly, weekly and ultimately on daily basis which would be used in the day ahead scheduling.
  - (h) Based on such demand estimation for daily/weekly/monthly/yearly basis SLDC will prepare load generation balance plan for that year. The SLDC shall carry out this demand estimate for operational planning purposes.
  - (i) Based on this demand estimate and the estimated availability from different sources, SLDC shall plan demand management measures like load shedding, power cuts etc., and shall ensure that the same is implemented by the distribution licensees. All distribution licensees shall abide by the demand management measures of the SLDC and shall also maintain historical data base for demand estimation.
  - (j) SLDC shall carry out its own demand estimation from the historical data and weather forecast data from time to time. All distribution licensees and other concerned persons shall provide relevant data and other information as required by SLDC for demand estimation.
  - (k) To carry out demand estimation for operational purposes on a daily//weekly/monthly/yearly basis, mechanisms and facilities at SLDC shall be created to facilitate online estimation of demand for daily operational use for each 15 minutes block.
  - (l) The SLDC shall take in to account the wind energy forecasting to estimate the active and reactive power availability.
  - (m) Based on its demand estimation on daily/weekly/monthly /yearly basis for current year for load - generation balance planning, the SLDC shall carry out system studies for operational planning purposes using this demand estimate. SLDC shall plan demand management measures like load shedding, power cuts, etc. and shall ensure that the same is implemented by the distribution licensees.
  - (n) All distribution licensees shall abide by the demand management measures of the SLDC and shall also maintain historical database for demand estimation.

## 6.4 Demand Management

### 6.4.1 Introduction

This Section is concerned with the provisions to be made by SLDC / ALDCs to effect a reduction of demand in the event of insufficient generating capacity, and inadequate transfers from external interconnections to meet demand, or in the event of breakdown or congestion in intra-State or inter-State transmission system or other operating problems (such as frequency, voltage levels beyond normal operating limit, or thermal overloads, etc.) or over drawal of power vis-à-vis of the regional entities beyond the limits mentioned in the Regulations of CERC from time to time.

### 6.4.2 Demand Disconnection

- (a) SLDC / ALDCs / Distribution licensees and bulk consumers shall initiate action to reduce the drawal by their control area, from the grid, within the net drawal schedule whenever the system frequency falls below frequency specified by CERC from time to time.
- (b) The SLDC / ALDCs / Distribution licensee and bulk consumers shall ensure that requisite load shedding is carried out in their control area so that there is no over drawal when frequency below the limit specified by CERC from time to time.
- (c) Each User shall formulate contingency procedures and make arrangements that will enable demand disconnection to take place, as instructed by the SLDC, under normal and/or contingent conditions. These contingency procedures and arrangements shall regularly be updated by User/STU and monitored by SLDC. SLDC may direct any User / STU to modify the above procedures/arrangement, if required, in the interest of grid security and the concerned User/STU shall abide by these directions.
- (d) The SLDC through respective ALDCs / Distribution Licensees shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response (which may include lower tariff for interruptible loads) etc., to reduce over drawal in order to comply with clause 6.4.2 (a) and (b) above. A Report detailing the scheme and periodic reports on progress of implementation of the schemes shall be sent to the Commission by the SLDC.



- (e) In order to maintain the frequency within the stipulated band and maintaining the network security, the interruptible loads shall be arranged in four groups of loads, for scheduled power cuts/load shedding, loads for unscheduled load shedding, loads to be shed through under frequency relays / df/dt relays and loads to be shed under any System Protection Scheme identified at the SRPC level. These loads shall be grouped in such a manner, that there is no overlapping between different groups of loads. In case of certain contingencies and/or threat to system security, the ALDCs / Distribution licensee/s or bulk consumer connected to the In-STS to decrease drawal of its control area by a desired quantum. Such directions of SLDC shall immediately be acted upon and the respective Agencies shall send compliance report immediately after compliance of these directions to SLDC.
- (f) All Users, Distribution licensee or bulk consumer shall comply with direction of SLDC and carry out requisite load shedding or backing down of generation in case of congestion in transmission system to ensure safety and reliability of the system. The procedure for application of measures to relieve congestion in real time as well as provisions of withdrawal of congestion shall be in accordance with the Central Electricity Regulatory Commission (Measures to relieve congestion in real time operation) Regulations, 2009.
- (g) The measures taken by the Users, Distribution licensee or bulk consumer shall not be withdrawn as long as the frequency remains at a level lower than the limits specified in clauses 6.4.2 (a) & (b) above or congestion continues, unless specifically permitted by the SLDC.

## **6.5 Load Crash**

**6.5.1** In the event of load crash in the system due to weather disturbances or any other reason, the situation would be controlled by SLDC by the following methods in descending priorities:

- i. Lifting of the load restrictions, if any.
- ii. Exporting the power to neighboring regions/ States provided the same does not endanger the security of the ISTS.
- iii. Backing down of thermal stations with a time lag of 5-10 minutes for short period in merit order.
- iv. Closing down of hydel units (subject to non-spilling of water and effect on irrigation) keeping in view the inflow of water into canals and safety of canals/hydel channels.



**6.5.2** While implementing the above, the system security aspects should not be violated as per the provisions in Section 5.2 of IEGC.

## **6.6 Operational Liaison**

### **6.6.1 Introduction**

(a) This Grid Code sets out the requirements for the exchange of information in relation to Operations and/or Events on the total grid system which have or will have an effect on:

- 1) The ISTS in the Region
- 2) The system of a User and STU

b) The Operational liaison function is a mandatory built-in hierarchical function of the SLDC, STU, ALDC, DISCOMs and Users, to facilitate quick transfer of information to operational staff. It will correlate the required inputs for optimization of decision making and actions.

### **6.6.2 Procedure for Operational Liaison**

#### ***Operations and events on a User/STU system:***

- i. Before any operation is carried out by a User, STU or transmission licensee shall obtain permission of the SLDC, and give details of the operation to be carried out. In case such operation is likely to have impact on other regions, the RLDC of those Regions shall also be informed.
- ii. All planned outages shall be communicated to SLDC by the 20<sup>th</sup> of the previous month so as to enable SLDC to study the impact and communicate to SRPC before 25<sup>th</sup> of previous month for outage coordination approval.
- iii. Immediately following an event, the User, STU, transmission licensee or DISCOM shall inform the SLDC about the event. All operational instructions given by SLDC shall have unique codes which shall be recorded and maintained as specified in the Central Electricity Authority (Grid Standards) Regulations, 2010.

## **6.7 Outage Planning**

### **6.7.1 Introduction**

a) This Section sets out the procedure for preparation of outage schedules for the elements of the State grid in a coordinated and optimal manner

keeping in view the Regional system operating conditions and the balance of generation and demand. (List of elements of grid covered under these stipulations shall be prepared and be available with SLDC).

- b) The generation output and transmission system should be adequate after taking into account the outages to achieve the security standards.
- c) Annual outage plan for the EHV transmission system in the State will be prepared in advance for the financial year by the SLDC in consultation with SRPC and reviewed during the year on quarterly and monthly basis.

All Users, STU and transmission licensee(s) shall follow these annual outage plans. 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, co-generation plants and its associated evacuation network shall be planned during off season. For Ex: Outage of wind generator should be planned during lean wind season, outage of solar, if required during the rainy season and outage of run-of-the river hydro power plant in the lean water season.

### **6.7.2 Objective**

- a) To produce a coordinated generation and transmission outage programme for the State grid, considering all the available resources and taking into account transmission constraints, as well as, irrigational requirements.
- b) To minimise surplus or deficits, if any, in the system requirement of power and energy and help operate system within Security Standards.
- c) To manage the transmission element outages of the State grid without adversely affecting the grid operation but taking into account the Generation Outage Schedule, outages of User/STU/CTU systems and maintaining system security standards.

### **6.7.3 Outage Planning Process**

- a) The SLDC will be primarily responsible for finalization of the Annual Load Generation Balance Report (LGBR) and the annual outage plan for the following financial year by 31<sup>st</sup> December of each year. The LGBR will be prepared for peak as well as off-peak scenarios.

- b) The STU, transmission licensees, IPPs, and other generating stations shall provide to the SLDC their proposed outage plan in writing for the next financial year by 31st October of each year. These shall contain identification of each generating unit/transmission line/ICT etc., the preferred date for each outage and its duration, and where there is flexibility, the earliest start date and latest finishing date. SLDC shall prepare LGBR for its control area, for peak as well as off-peak scenario, by 31<sup>st</sup> December for the next financial year and submit the same to the Commission. The annual plans for managing deficits/surpluses in the control area shall clearly be indicated in the LGBR submitted by SLDCs to KERC.
- c) The draft LGBR and draft outage plan shall be uploaded by the SLDC on its website.
- d) The final outage plan and the final LGBR shall be intimated by SLDC to Users, STU, CTU, RLDC and other generating stations connected to the In-STS by 31<sup>st</sup> December of each year for implementation.
- e) The above annual outage plan will be reviewed by SLDC on quarterly and monthly basis in coordination with all parties concerned, and adjustments made wherever found to be necessary.
- f) In case of emergency in the system, viz., loss of generation, break down of transmission line affecting the system, grid disturbances, system isolation, SLDC may clear the planned outage after conducting necessary studies.
- g) SLDC is authorized to defer the planned outage in case of any of the following, taking into account the statutory requirements:
  - i. Grid disturbances
  - ii. System isolation
  - iii. Partial Black out in the State
  - iv. Any other event in the system that may have an adverse impact on the system security by the proposed outage.
- h) The detailed generation and transmission outage programmes shall be based on the latest annual outage plan (with all adjustments made to date).

- i) Each User and STU shall obtain the final approval from SLDC / RLDC prior to availing an outage.

## **6.8 Contingency planning**

### **6.8.1 Introduction**

- a. This Section describes the steps in the recovery process to be followed by all users in the event of total or partial blackouts of the State/ Regional transmission system
- b. The objective of contingency planning is to design the responsibility of all users to achieve the fastest recovery in the event of the State transmission system or Regional system block out, taking in to account essential loads, generator capabilities and system constraints.

### **6.8.2 Contingency planning procedure**

1. SLDC shall be prepared to efficiently handle the following types of contingency and restoration of the system back into steady state
  - a. Partial system blackout in the State grid due to multiple tripping of the Transmission lines emanating from major generating stations/main receiving stations.
  - b. Total blackout in the State /Region.
  - c. Partial grid disturbances resulting in formation of islands and system split.
2. In case of partial blackout in the State / Regional grid, priority is to be given for early restoration of generating units which have tripped. Startup power for such generating stations shall be extended through shortest possible route and within shortest possible time from adjoining substations/ generating stations where the supply is available. Synchronizing facility at all generating stations and 220 kV and above substations shall be available.
3. In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of SRLDC for early restoration of the entire grid. Start-up power to the thermal stations shall be given by the hydel stations or through inter-State supply, if available. All possible efforts shall be made to extend the hydel supply to the thermal power stations through shortest transmission network so as to avoid high voltage problem due to low load conditions. For safe and fast

restoration of supply, SLDC shall formulate the proper sequence of operation for major generating units, lines, transformers and load within the State in consultation with SRLDC. The sequence of operation shall include opening, closing/tripping of circuit breakers, isolators, on-load tap-changers etc.

## 6.9 Recovery Procedures

- a) Detailed plans and procedures for restoration after partial/total blackout of In-ST\$ will be finalized by the SLDC/STU in coordination with the RLDC. The procedure will be reviewed, confirmed and/or revised once every subsequent year. Mock trial runs of the procedure for different subsystems shall be carried out by the SLDC / STU at least once every six months under intimation to SRLDC. Diesel Generator sets for black start shall be tested on weekly basis and test report shall be sent to SLDC on a quarterly basis.
- b) List of generating stations with black start facility, synchronizing points and essential loads to be restored on priority, shall be prepared and be available with SLDC.
- c) The SLDC is authorized during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.
- d) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.
- e) All Users shall pay special attention to implement the instructions of SLDC and to carry out the recovery procedures so that secondary collapse due to undue haste or inappropriate loading is avoided.
- f) Despite the urgency of the situation, careful, prompt and complete logging of all operations and operational messages shall be ensured by all Users to facilitate subsequent investigation in to the incident and efficiency of the restoration process. Such investigation shall be conducted promptly after the incident and discussed in the (Protection Coordination Committee) PCC Forum of SPRC and placed before the Grid Code Review Panel in its next meeting.

## **6.10 Operational Event/ Accident Reporting**

### **6.10.1 Introduction**

- a) This Section covers the details of requirement for the exchange of information relating to operations and/or events in the total system, including the southern grid which have or may have an operational effect on:
- (i) The Karnataka Grid in case of an operation and/or event occurring on a user system.
  - (ii) A user system in case of an operation and/ or event in the transmission system the procedure for issue of warnings in the event of a risk of serious and wide spread disturbances on the whole or part of Karnataka State power grid is set out in this Section.
  - (iii) This section applies to SLDC, STU and all entities embedded within the State power system that is under the control and supervision of SLDC.

### **6.10.2 Objective**

The objective of this Section is to define the events/ incidents to be reported, the reporting route to be followed and the information to be supplied to ensure a consistent approach in reporting of incidents and accidents in the State Transmission System.

### **6.10.3 Reportable Events**

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

- a. Exceptionally high / low system voltage or frequency.
- b. Serious equipment problem relating to major circuit breaker, transformer or bus bar.
- c. Loss of major Generating Unit, system split, State Transmission System breakaway or Black Start.
- d. Tripping of Transmission Lines, ICTs (Inter connecting transformer) and capacitor banks.
- e. Major fire incidents.
- f. Force-Majeure condition like flooding or lightning etc.
- g. Major failure of protection.
- h. Equipment and Transmission Line overload.

- i. Accidents-Fatal and Non-Fatal.
- j. Load Crash / Loss of Load
- k. Excessive Drawal deviations.
- l. Minor equipment alarms.

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

#### **6.10.4 Reporting Procedure**

##### **1. Reporting Time for events and accidents**

All reportable incidents occurring on lines and equipment of 33 kV and above and all the lines on which there is the inter user flow affecting the State Transmission System shall promptly be reported orally by the User whose equipment has experienced the incident (the reporting User) to any other significantly affected users and to SLDC. The reporting User should submit a written confirmation to SLDC within one hour of such oral report.

If the reporting incident is of major nature, then the reporting User shall submit an initial written report within two hours to SLDC. This has to be further followed up by the submission of a comprehensive report within 24 hours of the submission of the initial written report.

In other cases, the reporting User shall submit a report within 5 (five) days to SLDC.

2. SLDC shall call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been the source of the reportable incident. The above shall not relieve any User from the obligation to report events in accordance with Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010. The format of such a report shall be as agreed by the State Grid Code Review Panel, but will typically contain the following information:

- i. Location of incident.

- ii. Date and time of incident.
- iii. Plant or equipment involved.
- iv. Details of relay indications with nature of fault implications.
- v. Antecedent conditions like line flows, bus voltage, generation and demand supplies and quantum interrupted and duration if applicable.
- vi. Amount of generation lost if applicable and its duration.
- vii. Brief description of incident.
- viii. weather condition during the incident.
- ix. Estimate of time to return to service.
- x. Name of Organization.
- xi. Possibility of alternate arrangement of supply.

### **6.10.5 Reporting Form**

The standard reporting form other than for accidents shall be as agreed from time to time by the Grid Code Review Panel. A typical form is attached (APPENDIX-E).

### **6.10.6 Major Grid Incidence**

- (a) Following a major grid incident, SLDC and other Users shall cooperate to enquire and establish the cause of such failure and make appropriate recommendations. SLDC shall report the occurrence of such major grid failure to the SRPC \ Commission in writing as well as SRLDC immediately for information and shall submit the enquiry report to the Commission within two months of the incident. Analysis of major grid disturbance in the Intra-State Power System soon after their occurrence shall be done by a Protection Sub- Committee constituted by STU. If the disturbance is of major nature the SRPC will also conduct detailed analysis of the incident. The User, the generator, the ESCOM and the STU shall furnish required data to SRPC.
- (b) Periodic Reports –STU/Transmission licensee shall send a weekly report to SLDC on the performance of their respective systems which should cover the following information:
  - (i) Voltage profile at all Substations – 66kV/110kV and above.
  - (ii) Average, maximum, minimum demand (both MW and MVAR) met at such Substations.
  - (iii) Quantum and duration of load shed, with reasons.
  - (iv) Outage of major elements.
  - (v) Network constraints.
  - (vi) Daily energy consumed and energy exchanged by the DISCOM.



- (c) The SLDC shall post on its website a monthly performance report of the State as a whole covering:
  - (i) Hourly demand met and generation for peak and minimum demand met on every day. Also the average daily off-peak and peak demands met.
  - (ii) Daily average consumption.
  - (iii) Station wise daily maximum, minimum and average generation (MW), together with daily energy generation.
  - (iv) Instances of non-compliance of the State Grid Code.
  - (v) Progress of construction of new generating units, lines and transformers.
  - (vi) Details of generation and transmission outages during the month.

#### **6.10.7 Warnings**

- (i) An oral warning shall be issued by SLDC and confirmed in writing as well, to the STU/ Transmission Licensee and the users, who may be affected when SLDC knows that there is a risk of widespread and serious disturbance to the whole, or part of the total system.
- (ii) Provided that sufficient time is available, the warning shall contain such information as the SLDC considers reasonable, to explain the nature, extent of the anticipated disturbance, to the user and STU/ Transmission Licensee, provided that such information is available to SLDC.
- (iii) Each user and STU/ Transmission Licensee, on receipt of such a warning, shall take necessary steps to warn the operational staff and maintain their plant and apparatus in the condition in which it is best able to withstand the anticipated disturbance for the duration of the warning.
- (iv) Scheduling and despatch may be affected during the period covered by such a warning.

#### **6.10.8 Loss of communication with SLDC**

- (i) In the event of loss of communication with SLDC, the provision made as above shall not apply; instead, the following provision shall apply:
- (ii) Each generating station shall continue to operate in accordance with the last despatch instruction issued by SLDC, but shall use all reasonable endeavours to maintain the system frequency at the target of 50 Hz, plus or minus 0.05 Hz by monitoring frequency, until such time the new despatch instructions are received from SLDC.

### **6.10.9 Major Failure**

Whenever a major failure takes place, STU/ Transmission Licensee and other users shall cooperate, inquire and establish the cause of the failure and produce appropriate recommendations. The STU shall submit the inquiry report to the Grid Code Review Panel. Based on the analysis of report, the panel shall suggest modifications to the Grid Code, if any, within two months of the incident to the Commission for approval.

### **6.10.10 Accident Reporting**

Report of accidents shall be in accordance with the Section 161 of the Electricity Act, 2003 and the Rules framed thereunder. Reporting of accident and failure of supply or transmission of electricity shall be in the specified form to the Commission and the Electrical Inspector.

## SECTION -7

### CROSS BOUNDARY SAFETY

#### 7.1 Introduction

This Section specifies the requirements for safe working practices for maintenance of equipment associated with cross boundary operations. It lays down the procedure to be followed when work is required to be carried out on electrical equipment that is connected to another User's system.

#### 7.2 Objective

The objective of this Section is to achieve an agreement on the principles of safety as specified in the Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010, when working across the inter user boundary between one User and another User.

#### 7.3 Designated Officers/ Control Persons.

STU and all Users shall nominate suitable authorized persons to be responsible for the co-ordination of safety across their boundary. These persons shall be referred to as Designated Officer(s) (or control person(s)).

#### 7.4 Procedure

1. STU shall issue a list of Designated Officers (names, designations and telephone numbers) to all Users who have a direct inter user boundary with STU or other Users. This list shall be updated promptly whenever there is change of name, designation or telephone number.
2. All Users with a direct inter user boundary with STU or other User system shall issue a similar list of their Designated Officers to STU or other User(s), which shall be updated promptly whenever there is a change in the list.
3. Whenever work across a cross boundary / an inter-user boundary is to be carried, the Designated Officer of the User including STU itself, wishing to carry out work shall personally contact the other relevant Designated Officer. If the Permit to Work (PTW)/ Line Clear permit cannot be obtained personally, the Designated Officers shall contact through telephone and exchange Code words to ensure correct identification of both agencies.

4. Should the work extend over more than one shift, the Designated Officer shall ensure that the relief Designated Officer is fully briefed on the nature of the work and the code words in operation.
5. The Designated Officer(s) shall co-operate to establish and maintain the precautions necessary for the required work to be carried out in a safe manner. Both the established isolation and the established earth shall be locked in position, where such facilities exist, and shall be clearly identified.
6. SLDC shall be the nodal agency in real time for clearing outages. STU and All users shall approach SLDC for executing the maintenance work. Work shall not commence until the Designated Officer of the User including STU itself, wishing to carry out the work, is satisfied that all the safety precautions have been established. This Designated Officer shall issue agreed safety documentation (PTW)/ line clear permit to the working party to allow work to commence. **The PTW /LCP in respect of specified EHV lines and other interconnections shall be issued with the consent of SLDC.**
7. When work is completed and safety precautions are no longer required, the Designated Officer who has been responsible for the work being carried out shall make direct contact with the other Designated Officer to return the PTW/LCP. Return of PTW in respect of specified EHV lines and interconnections shall be informed to SLDC.
8. The equipment shall only be considered as suitable for connecting back to service when all safety precautions are confirmed as removed, by direct communication using code word contact between the two Designated Officers, and after ensuring that the return of agreed safety documentation (PTW /LCP) from the working party has taken place with prior approval of SLDC.
9. STU shall develop an agreed written procedure for inter-user boundary safety and continually update it.
10. Any dispute concerning inter-user boundary safety shall be resolved at the level of STU, if STU is not a party. In case STU is a party, the dispute shall be referred to Grid Code Review Panel and then to KERC.

### 7.5 Special Consideration

- 1) For inter-user boundary between STU and other User's circuits, all Users shall comply with the agreed safety rules, which must be in accordance with Safety Regulations or Rules framed under the Act.
- 2) Each Designated Officer shall maintain a legibly written safety logbook, in chronological order, of all operations and messages relating to safety

coordination sent and received by him. All safety logs shall be retained for a period of not less than 10 years.

- 3) Each of the Distribution licensees connected to the transmission system shall maintain an updated map of distribution system pertaining to the area fed by each substation and exhibit the same in respective substation. The same shall be uploaded in their websites.

## **7.6 Safety Standard and Line Clear Permit:**

### **7.6.1 Introduction**

This Section sets out the procedure for the record of the Line Clear Permit and sets guidelines for ensuring safety from electrical hazards to consumers, general public and working personnel.

### **7.6.2 Objective**

The main objective of this Section is to ensure safety to the working personnel of STU/ Transmission Licensee and users and maintenance of proper records for the issue of Line Clear Permits for allowing working personnel to carry out the works safely.

### **7.6.3 Safety Standards**

- 1) The Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010, issued separately formulates the precautions to be taken for ensuring safety to the general public, consumers of electricity and the workmen. This forms an integral part of the Grid Code and STU/ Transmission Licensee and all the users shall comply with this standard.
- 2) STU/ Transmission Licensee shall prepare his own safety manual for the Transmission Lines, substations based on this standard. For the guidance of the shift operators, Operation and Maintenance Manuals for each substation shall be prepared by the Licensee. These manuals shall contain all the maintenance and operation schedules, based on the recommendations of the manufacturers of the various equipment installed in the substation. These manuals shall be periodically reviewed based on the experience gained and replacement of equipment. A maintenance register for the equipment including the station batteries shall be maintained at the respective substations. These shall be updated as and when the maintenance work is carried out and shall be periodically reviewed by the appropriate higher authority in whose control the

substation falls. Similar registers shall be maintained for the Transmission Lines.

- 3) The Operation Manual shall clearly contain the details of isolation and earthing to be provided for allowing work on the equipment. The Single Line Diagram (SLD) of the substation indicating the positions of various isolating devices shall be prominently displayed in the station. Charts showing the clearances from live parts (section clearance) for working on the isolated equipment where workmen are allowed to work shall be displayed prominently at each substation.
- 4) The danger boards as stipulated in the Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010 and in relevant Indian Standards shall be displayed at the places approachable by the general public.
- 5) Regular maintenance shall be carried out on all the Transmission Lines in accordance with IS: 5613 and or relevant standards and records of all these shall be maintained. Wherever possible, hot line checking and replacement of failed insulators shall be made before and after every monsoon.
- 6) All the equipment in the receiving stations and substations shall be maintained in good condition as per the manufacturers' manuals and relevant Indian and/or International Standards wherever available. The relays and circuit breakers shall be checked for their proper operations whenever these are taken out for maintenance purposes. The station batteries shall be maintained in good working condition by carrying out routine checks and maintenance works. The DC system provided in all these stations shall be properly maintained with no appreciable leakage current. An online monitoring system for monitoring of leakage and detection of ground faults shall be provided.

### **7.7 Format of Line Clear Permit (LCP)**

The form under **Annexure III** and designated as requisition for Line Clear Permit shall be used by the requesting safety coordinator, who is an authorized person. The form under **Annexure IV** and designated as check list for Line Clear Permit and Line Clear Permit shall be used at the time of issue of Line Clear Permit. The form under **Annexure V** and designated as Line Clear Return shall be used for the return of the Line Clear Permit after the work for which the Line Clear Permit was taken, is completed.

## SECTION- 8

### SCHEDULING AND DESPATCHING

#### 8.1 Introduction

This part sets out the:

- a) Demarcation of responsibilities between various Intra-State entities and SLDC in Scheduling and Despatch;
- b) The procedure for Scheduling and Despatch;
- c) The reactive power and voltage control mechanism;
- d) Complementary commercial mechanisms

#### 8.2 Objective

This code deals with the procedures to be adopted for scheduling of the net injection/ drawals of Intra-State entities concerned on a day ahead basis with the modality of the flow of information among the SLDC, ALDCs and Intra-State entities. The procedure for submission of capability declaration by each Intra-State Generating Station (In-SGS) and submission of requisition / drawal schedule by other State entities is intended to enable SLDC to prepare the Despatch Schedule for each Generating station and drawal schedule for each DISCOM. It also provides methodology of issuing real time Despatch / drawal instructions and rescheduling, if required, to Intra-State entities along with the commercial arrangement for the deviations from schedules, as well as, mechanism for reactive power pricing. The methodology for scheduling and despatch of wind and solar generating plant shall be as per the KERC (Forecasting, Scheduling, Deviation settlement and related matters for wind and solar Generation sources) Regulations, issued and amended from time to time.

#### 8.3 Scope

This code will be applicable to STU, SLDC, ALDCs, In-SGS, Distribution Licensees / Intra-State entities, including generators/ captive generating plant/ IPPs, wind and solar generating stations and other concerned persons in the State grid.

#### 8.4 Demarcation of responsibilities:

1. The SLDC shall coordinate the scheduling of all such generating stations in the State, which are not scheduled by RLDC under CERC Regulations as notified

from time to time. The SLDC shall also be responsible for such generating stations for:

- i. real time monitoring of the stations' operation;
  - ii. checking that there is no gaming in its availability declaration;
  - iii. revision of availability declaration and injection schedule;
  - iv. switching instructions;
  - v. metering and energy accounting;
  - vi. issuance of deviation (as per DSM) accounts in its control area;
  - vii. collections / disbursements of deviation (as per DSM) payments in its area;
  - viii. Outage planning etc.,.
2. Scheduling of a generating station supplying power to any State other than the host State will be as provided in the Scheduling and Despatch Code of the IEGC.
3. The Regional grids will be operated as power pools with decentralized scheduling and despatch, in which the States shall have operational autonomy, and SLDC shall have the total responsibility for
- i. scheduling / despatching State's own generation (including generation of its embedded licensees),
  - ii. regulating the demand of its control area,
  - iii. scheduling the drawal from the ISGS (within its share in the respective plant's expected capability)
  - iv. permitting inter-State long term access, medium term and short term open access transactions for embedded generators/consumers, in accordance with the contracts
  - v. regulating the net drawal of its control area from the regional grid in accordance with the respective regulations of the CERC and
  - vi. regulating the net drawal /injection of each DISCOM, Users of its control area as per the schedules.
4. The system of each regional entity shall be treated and operated as a notional control area. The algebraic summation of scheduled drawal from ISGS and from contracts through long-term access, medium-term and short-term open access arrangements shall provide the drawal schedule of each regional entity, and this shall be determined in advance on day-ahead basis. The regional *entities* shall regulate their generation and/or consumers' load so as to maintain their actual drawal from the regional grid close to the above schedule. Similarly, the



SLDC shall regulate the generation and load in its control area, so as to maintain its actual drawal close to its schedule from all the sources. Deviation, if any, from the drawal schedule, shall be within the limits specified by the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 for inter-State players and as per the limits specified by the KERC (forecasting, scheduling, deviation settlement and related matters for wind and solar generation sources) regulations, issued and amended from time to time for intra-State players and it shall not cause system parameters to deteriorate beyond permissible limits and shall not lead to unacceptable line loading. Such deviation from net drawal schedule shall be priced through the deviation (as per DSM) mechanism as specified by the Central Commission and State Commission from time to time.

5. The SLDC and distribution licensee(s) shall always endeavour to restrict the net drawal of the State from the grid to within the drawal schedules, whenever the system frequency is below the lower limit as specified by the CERC (IEGC) Regulations 2010 and its amendments from time to time. The concerned Distribution Licensee, User, SLDC shall ensure that their automatic demand management scheme mentioned in clause 5.4.2 of IEGC, acts to ensure that there is no over drawal below frequency band limit as specified by the CERC (IEGC) Regulations, 2010, and its amendments from time to time. If the automatic demand management scheme has not yet been commissioned or not working, then action has to be taken as per manual demand management scheme to ensure zero over drawal when frequency is below the lower limit as specified by the CERC (IEGC) Regulations, 2010, and its amendments issued from time to time.
6. The SLDC / STU / Distribution Licensees shall regularly carry out the necessary exercises regarding short-term demand estimation for the State / area to enable them to plan in advance as to how they would meet their consumers' load without overdrawing from the drawal schedule.
7. The In-SGS, other generating stations and sellers shall be responsible for power generation/power injection generally according to the daily schedules advised to them by the SLDC on the basis of the contracts/ requisitions received from the SLDC / buyers / Power Exchanges.
8. The In-SGS would normally be expected to generate power according to the daily schedules advised to them. The In-SGS may also deviate from the given schedules within the limits specified in the DSM Regulations of CERC, depending

on the plant and system conditions. In particular, they may be allowed to generate beyond the given schedule under deficit conditions as long as such deviations do not cause system parameters to deteriorate beyond permissible limits and/or do not lead to unacceptable line loading. Deviations, if any, from the ex-power plant generation schedules shall be appropriately priced in accordance with DSM Regulations of CERC. In addition, deviations, from schedules causing congestion, shall also be priced in accordance with the Congestion Charge Regulations of CERC. The treatment of injection of infirm power by generating stations during testing shall be in accordance with the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009, and the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014, and amendments issued from time to time.

9. Provided that when the frequency is higher than 50.05 Hz, the actual net injection shall not exceed the scheduled despatch for that time block. Also, while the frequency is above the limit as specified by the CERC (IEGC) Regulations 2010 and its amendments from time to time, the In-SGS may (at their discretion) backdown without waiting for an advice from SLDC / RLDC to restrict the frequency rise. When the frequency falls below limit as specified by the CERC (IEGC) Regulations 2010 and its amendments from time to time, the generation at all In-SGS (except those on peaking duty) shall be maximized, at least upto the level to which can be sustained, without waiting for an advice from SLDC / RLDC subject to the condition that such increase does not lead to unacceptable line loading or system parameters to deteriorate beyond permissible limit.
10. However, notwithstanding the above, the SLDC may direct the DISCOMs / In-SGS to increase/decrease their drawal/generation in case of contingencies e.g. overloading of lines/transformers, abnormal voltages, threat to system security. Such directions shall immediately be acted upon. In case the situation does not call for very urgent action, and SLDC has some time for analysis, it shall be checked whether the situation has arisen due to deviations from schedules, pursuant to short-term open access. These shall be got terminated first, before an action, which would affect the scheduled supplies to the long term and medium term customers is initiated.
11. For all outages of generation and transmission system, which may have an effect on the regional grid, SLDC shall cooperate with other Regional entities

- to coordinate the action to be taken through Operational Coordination Committee (OCC) for outages foreseen sufficiently in advance and through RLDC (in all other cases), as per procedures finalized separately by OCC. In particular, outages requiring restriction of ISGS generation and/or restriction of ISGS share which the State can receive and curtailment of other long term transactions shall be planned carefully to achieve the best optimization.
12. The In-SGS shall make an advance declaration of ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 00:00 hrs to 24:00 hrs. During fuel shortage condition, in case of thermal stations, they may specify minimum MW, maximum MW, MWh capability and declaration of fuel shortage. The generating stations shall also declare the possible ramping up / ramping down in a block. In case of a gas turbine generating station or a combined cycle generating station, the generating station shall declare the capacity for units and modules on Administrative Price Mechanism (APM) gas, Re-gasified-liquid natural gas (RLNG) and liquid fuel separately, and these shall be scheduled separately.
  13. While making or revising its declaration of capability, except in case of Run of the River (with up to three hour pondage) hydro stations, the In-SGS shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronization of units as a result of forced outage of units.
  14. It shall be incumbent upon the In-SGS to declare the plant capabilities faithfully, i.e., according to their best assessment. In case, it is suspected that they have deliberately over/under declared the plant capability contemplating to deviate from the schedules given on the basis of their capability declarations (and thus make money either as undue capacity charge or as the charge for deviations from schedule), the SLDC may ask the In-SGS to explain the situation with necessary backup data.
  15. The In-SGS shall be required to demonstrate the declared capability of its generating station as and when asked by the State Load Despatch Centre. In the event of the In-SGS failing to demonstrate the declared capability, such reduction in capacity shall be informed by SLDC to the respective DISCOM who has PPA with such generator and the concerned DISCOM shall reduce the capacity charges on pro-rata basis due to the generator as a measure of penalty.

16. The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression over a period of a month.
17. The STU or Transmission licensee shall install special energy meters (SEM) on all inter-face points with the Distribution Licensees and other identified points between Distribution Licensees for recording of actual net MWh interchanges and MVArh drawals. The installation, operation and maintenance of special energy meters shall be in accordance with the CEA (Installation and Operation of Meters) Regulations, 2006 and amendments issued from time to time. All concerned entities (in whose premises the special energy meters are installed) shall take weekly meter readings and transmit them to the SLDC by scheduled time.
18. The operating log books of the generating station shall be available for review by the Grid Code Review panel, Regional Power Committee and KERC. These books shall keep record of machine operation and maintenance.
19. Hydro generating stations are expected to respond to grid frequency changes and inflow fluctuations. The hydro generating stations shall be free to deviate from the given schedule without causing grid constraint and a compensation for difference between the actual net energy supply by the hydro generating station and the scheduled energy (ex-bus) over day shall be made by the SLDC in the day ahead schedule for the 4<sup>th</sup> day (day plus 3).
20. SLDC shall periodically review the actual deviation from the Despatch and net drawal schedules being issued, to check whether any of the inter-State or Intra-State entities are indulging in unfair gaming or collusion. In case any such practice is detected, the matter shall be reported to the KERC and CERC for further investigation.

### **8.5 Scheduling and Despatch procedure:**

Scheduling and Despatch procedure including long-term access, medium-term and short-term open access (to be read with provisions of Open Access Regulations as amended from time to time). The scheduling procedure for medium-term open access transactions shall be similar to the scheduling procedure for long-term access transactions and is as given below:

1. All inter-State generating stations (ISGS) of the Southern Region and all intra-State generating stations (In-SGS) of the State shall be duly listed on the SLDC web-site. The station capacities and allocated /contracted Shares of different beneficiaries shall also be listed out.
2. The State shall be entitled to a MW despatch upto (foreseen ex-power plant MW capability for the day) x (State's Share in the station's capacity) for all such stations in case of ISGS and entitled to a MW despatch upto the foreseen ex-power plant MW capability for the day from the In-SGS. In case of hydro-electric stations, there would also be a limit on daily MWh despatch equal to (MWh generation capacity for the day) X (State's Share in the station's capacity) in case of ISGS and a limit on daily MWh despatch equal to the MWh generation capacity for the day from In-SGS.
3. By 08 hours every day, the In-SGS shall inform the SLDC, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 00:00 hrs to 24:00 hrs of the following day.
4. The above information of the foreseen capabilities of the In-SGS with corresponding MW and MWh entitlements of the State, will be compiled by the SLDC every day for the next day, and advised to the beneficiaries by 10.00 hours. The SLDC shall review it vis-à-vis the foreseen load pattern and the State's own generating capability including bilateral exchanges, if any, and advise the RLDC by 15 hours its drawal schedule for each of the ISGS in which the State has shares, long-term, medium-term bilateral interchanges and approved short term bilateral interchanges.
5. Scheduling of collective transaction:
  - a. The individual transactions for State Utilities/intra-State entities shall be scheduled by the SLDC. Power Exchange(s) will send the detailed breakup of each point of injection and each point of drawal within the State to SLDC after receipt of acceptance from NLDC. Power Exchange(s) will ensure necessary coordination with SLDC for scheduling of the transactions.
  - b. Timeline for above activities will be as per detailed procedure for Scheduling of Collective Transaction issued in accordance with the CERC (Open access in inter-State transmission) Regulations, 2008 and the

KERC [Terms and Conditions for Open Access] Regulations, 2004 as amended from time to time.

6. The SLDC shall inform any modifications/changes to be made in drawal schedule/foreseen capabilities, if any, to RLDC by 22.00 hours or preferably earlier.
7. The declaration of the generating capability by hydro In-SGS shall include limitation on generation during specific time periods, if any, on account of restriction(s) on water use due to irrigation, drinking water, industrial, environmental considerations etc. The SLDC shall periodically check that the generating station is declaring the capacity and energy sincerely, and is not manipulating the declaration.
8. Since variation of generation in run-of-river power stations shall lead to spillage, these shall be treated as must-run stations. All renewable energy power plants, except for biomass power plants and non-fossil fuel based cogeneration plants whose tariff is determined by the KERC shall be treated as 'MUST RUN' power plants and shall not be subjected to 'merit order despatch' principles. Provided that, in case of low load conditions, the SLDC shall regulate the generation of Renewable energy power plants to maintain Grid security.
9. Run-of-river power station with pondage and storage type power stations are designed to operate during peak hours to meet system peak demand. Maximum capacity of the station declared for the day shall be equal to the installed capacity including overload capability, if any, minus auxiliary consumption, corrected for the reservoir level. The State Load Despatch Center shall ensure that generation schedules of such type of stations are prepared and despatched for optimum utilization of available hydro energy except in the event of specific system requirements / constraints.
10. The schedule finalized by the SLDC for hydro generating station, shall normally be such that the scheduled energy for a day equals the total energy (ex-bus) expected to be available on that day, as declared by the generating station, based on foreseen/planned water availability/release. It is also expected that the total net energy actually supplied by the generating station on that day will equal the declared total energy, in order that the water release requirement is met.

11. While finalizing the above daily despatch schedules for the In-SGS, SLDC shall ensure that the same are operationally reasonable, particularly in terms of ramping-up/ramping-down rates and the ratio between minimum and maximum generation levels.
12. While finalizing the drawal and despatch schedules as above, the SLDC shall also check that the resulting power flows do not give rise to any transmission constraints. In case any impermissible constraints are foreseen, the SLDC shall moderate the schedules to the required extent. Any changes in the scheduled quantum of power which are too fast or involve unacceptably large steps may be converted into suitable ramps by the SLDC.
13. In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and substations owned by the State Transmission Utility or any other transmission licensee involved in intra-State transmission (as certified by the SLDC) necessitating reduction in generation, the SLDC shall revise the schedules which shall become effective from the 4<sup>th</sup> time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the scheduled generation of the In-SGS shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised accordingly.
14. In case of any grid disturbance, scheduled generation of all the In-SGS and scheduled drawal of all the Distribution Companies shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the SLDC / RLDC.
15. Revision of declared capability by the In-SGS(s) having two-part tariff with capacity charge and energy charge (except hydro stations) and requisition by Distribution Licensees for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 4<sup>th</sup> time block, counting the time block in which the request for revision has been received in the RLDC to be the first one. Provided that SLDC may allow revision, of the declared capacity (DC) at 6 hourly intervals effective form 00:00, 06:00,12:00 and 18:00 hours in case of Run-of-the-River (ROR) and pondage based hydro generating



stations, if there is large variation of expected energy (MWh) for the day compared to previous declaration.

16. Notwithstanding anything contained in Regulation 8.5.15 of this Code, in case of forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under Short Term bilateral transaction (excluding collective transactions through power exchange), the generator or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to the SLDC. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised accordingly. The revised schedules shall become effective from the 4<sup>th</sup> time block, counting the time block in which the forced outage is declared to be the first one. The SLDC shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit. However, the transmission charges as per original schedule shall continue to be paid for two days. Provided that the schedule of the buyers and sellers shall be revised after forced outage of a unit, only if the source of power for a particular transaction has clearly been indicated during short-term open access application and the said unit of that generating station goes under forced outage.

Provided also that, the provision of this sub-regulation in respect of revision of schedule of electricity is applicable to traders and any other agencies (except the generating station).

In case of revision of schedule of a generating unit, the schedules of all transactions under the long-term access, medium-term open access and short-term open access (except collective transactions through power exchange), shall be reduced on pro-rata basis.

17. If, at any point of time, the SLDC observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own, and in such cases, the revised schedules shall become effective from the 4<sup>th</sup> time block, counting the time block in which the revised schedule is issued by the SLDC as to be the first one.

18. To discourage frivolous revisions, SLDC may, at its sole discretion, refuse to accept schedule/capability changes of less than two (2) percent of previous schedule/capability. The schedule of thermal generating stations indicating



fuel shortage while intimating the Declared Capacity to the SLDC shall not be revised except in case of forced outage of generating unit.

Provided that in case of gas based In-SGS, for optimum utilization of gas, this shall be permitted, i.e., in case of tripping of a unit, this gas may be diverted to another unit using the same gas.

19. The State Load Despatch Centre shall also formulate the procedure for meeting contingencies both in the long run and in the short run (daily scheduling).

20. Special dispensation for scheduling of wind and solar generation:

(i) Scheduling of Wind and Solar power generation plants would have to be done for the purpose of computing deviation where the sum of generation capacity of such plants are clubbed at a Pooling Station and connected through a line(s) at the connection point to the transmission or distribution system is 10 MW and above and connection point is 33 KV and above, and where PPA has not yet been signed. For capacity and voltage level below this, as well as for old Wind farms (A wind farm is collection of wind turbine generators that are connected to a common connection point commonly known as Pooling Station), it could be mutually decided between the Wind Generator and the transmission or distribution utility, as the case may be, if there is no existing contractual agreement to the contrary. The schedule by wind power generating stations (excluding collective transactions) may be revised by giving advance notice to SLDC. The revisions by wind power generating stations and solar power generating stations shall be effective from 4<sup>th</sup> time block, the first being the time-block in which notice was given. There may be one revision for each time slot of 1.5 hours starting from 00:00 hours of a particular day subject to a maximum of 16 revisions during the day or as specified in KERC (Forecasting, Scheduling, Deviation settlement and related matters for wind and solar Generation sources) Regulations, issued and amended from time to time.

(ii) The schedule of solar generation shall be given by the generator based on availability of the generator, weather forecasting, season and normal solar generation curve and shall be vetted by the SLDC. If SLDC is of the opinion that the schedule is not realistic, it may ask the solar generator to modify the schedule.

- (iii) SLDC shall maintain the record of schedule from renewable power generating stations based on type of renewable energy sources i.e., wind or solar from the point of view of grid security. While scheduling generating stations in the State, system operator shall aim at utilizing available wind and solar energy fully.
21. Generation schedules and drawal schedules issued/revised by the State Load Despatch Centre shall become effective from designated time block irrespective of communication success.
22. For any revision of scheduled generation, including post facto deemed revision, there shall be a corresponding revision of scheduled drawals of the beneficiaries.
23. A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by the SLDC.
24. When for the reason of transmission constraints e.g. congestion or in the interest of grid security, it becomes necessary to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed by the State Load Despatch Centre.
25. The short-term customer shall be curtailed first followed by the medium term customers, which shall be followed by the long-term customers and amongst the customers of a particular category, curtailment shall be carried out on *pro-rata* basis.
26. After the operating day is over at 24:00 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of generating stations and drawal schedule of the ESCOMs and other users) shall be issued by the SLDC. These schedules shall be the data for commercial accounting. The average ex-bus capability for each ISGS shall also be worked out based on all before-the-fact advice to SLDC.
27. Collective Transaction through Power Exchange(s) would normally be curtailed subsequent to the Short Term Bilateral Transaction(s).

28. RLDC will curtail a Transaction at the periphery of the Regional Entities. SLDC shall further incorporate the curtailment of intra-State Entities to implement the curtailment.
29. while availability declaration by the In-SGS shall have a resolution of one (1) MW and one (1) MWh, all entitlements, requisitions and schedules shall be rounded off to the nearest two decimal at each control area boundary for each of the transactions, to have a resolution of 0.01 MW and 0.01 MWh."

## **8.6 Reactive Power and Voltage Control**

**8.6.1** Reactive power compensation should ideally be provided locally, by generating Reactive Power as close to the Reactive Power consumption as possible. The beneficiaries are therefore expected to provide local VAR compensation/generation, such that they do not draw VARs from the state grid, particularly under low-voltage conditions. However, considering the present limitations, this is not being insisted upon. Instead, to discourage VAR draws by beneficiaries, VAR exchanges with Intra-State Transmission System shall be priced as follows:

- (a) The beneficiary pays for VAR drawal when voltage at the metering point is below 97%,
- (b) The beneficiary gets paid for VAR return when voltage is below 97%,
- (c) The beneficiary gets paid for VAR drawal when voltage is above 103%,
- (d) The beneficiary pays for VAR return when voltage is above 103%.

**8.6.2** The charge/payment for VARs shall be at a nominal paise/kVArh rate as may be specified by the Central Electricity Regulatory Commission from time to time for inter-State transactions, and will be between the beneficiary and the State Pool Account for VAR interchanges.

Notwithstanding the above, SLDC may direct a beneficiary to curtail its VAR drawal/injection in case the security of grid or safety of any equipment is endangered.

**8.6.3** The SLDC may issue direction to any generator within the State to increase Var generation/absorption up to the machine capability limit. In general, the beneficiaries shall endeavour to minimize the VAR drawal at an interchange point when the voltage at that point is below 95% of the rated voltage and shall not return VAR when the voltage is above 105%. Transformer taps at the respective drawal points may be changed to control the VAR interchange as per the beneficiary's request to SLDC, but only at reasonable intervals. A

beneficiary may also request the SLDC for increase/decrease of VAR generation at a generating station for addressing a voltage problem.

**8.6.4** Switching in/out of all bus and line reactors throughout the state grid shall be carried out as per instructions of SLDC. Tap changing on all transformers in STU system shall also be done as per SLDC's instructions. The SLDC shall monitor the working of shunt capacitor banks installed in the substations of STU or transmission licensee and Distribution substation and direct them to switch in/out as and when required.

**8.6.5** The generating station shall change generator-transformer taps and generate/absorb Reactive Power as per the instructions of the SLDC, within capability limits of the respective generating units, that is, without sacrificing the active generation required at that time. No payments shall be made to the generating companies for such VAR generation/absorption.

**8.6.6** VAR exchanges directly between two beneficiaries on the interconnecting lines generally addresses or causes a local voltage problem, and generally do not have an impact on the voltage profile of the State grid. Accordingly, the management/control and commercial handling of the VAR exchanges on such lines shall be as per following provisions, on case-by-case basis:

- (i) The two concerned beneficiaries may mutually agree not to have any charge/payment for VAR exchanges between them on an interconnecting line,
- (ii) The two concerned beneficiaries may mutually agree to adopt a payment rate/scheme for VAR exchanges between them identical to or at variance from that specified by the KERC for VAR exchanges with the state transmission system. If the agreed scheme requires any additional metering, the same shall be arranged by the concerned beneficiaries,
- (iii) The computation and payments for such VAR exchanges shall be effected as mutually agreed between the two beneficiaries.

In case of a disagreement between the concerned beneficiaries (e.g. one party wanting to have the charge/payment for VAR exchanges, and the other party refusing to have the scheme), the scheme as specified in **Annexure VI** shall be applied.

## SECTION- 9

### PROTECTION AND METERING

#### 9.1 General Protection Requirements

STU, In-SGS, other embedded generators, ESCOMs and other bulk consumers shall abide by the provisions contained in Section 6 of the CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007.

- i. Protection system shall be designed to reliably detect faults on various abnormal conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protected zone.
- ii. Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity. Where failure of a protective relay in the requester's system has substantial impact on the grid, it shall connect an additional protection as backup protection besides the main protection.
- iii. Notwithstanding the protection systems provided in the grid, the requester and user shall provide requisite protections for safeguarding his system from the faults originating in the grid.
- iv. Special protection scheme such as under-frequency relay for load shedding, voltage instability, angular instability, generation backing down or islanding schemes may also be required to be provided to avert system disturbances.
- v. Protection co-ordination issues shall be finalized by the Regional Power Committee.
- vi. No item of electrical equipment shall be allowed to remain connected to the system, unless it is covered by the appropriate protection aimed at reliability, selectivity, speed and sensitivity. The guidelines mentioned in the manual on protection of generators, generator transformers, and 220 kV and 400 kV networks vide publication No. 274 & 296 of C.B.I.P and relevant Standards shall be kept in view.

- vii. All the generating companies and Distribution Licensees shall cooperate with the STU and Transmission Licensee(s) to ensure correct and appropriate settings of protection to achieve effective, discriminatory isolation of faulty line/equipment within the target clearance times specified elsewhere in this Standard.
- viii. Protection settings shall not be altered, or protection bypassed and/or disconnected without consultation and agreement of all affected users. In case the protection has been bypassed and/or disconnected by agreement due to any cause, the same should be rectified and protection restored to normal conditions, as quickly as possible. If agreement has not been reached, the electrical equipment shall be isolated forthwith.

## **9.2 Protection System Studies**

A dedicated group is required to be constituted and trained by STU, transmission licensee (s) and all Users to carry out computer aided studies for relay settings. It is also recommended that for settings of critical transmission lines and corridors, the relay setting calculations be validated by simulations on the Real Time Digital Simulator (RTDS) available with CPRI and PGCIL.

STU may appoint a reputed consultant to carry out studies (in which manpower from STU will also involve and get trained) to determine the relay settings for the complete network and also carry out the settings at site in coordination with the CTU and STU's with time-bound target for one time and the same shall be continued in house by STU.

## **9.3 Protection System Management:**

In addition to technical issues related to protection, the management issues related to protection system need to be addressed. In order to comprehensively address the protection issues in the STU, transmission licensee (s) and all Users, following are the recommendations.

### **9.3.1 Establishing Protection Application Department:**

- 1) STU, transmission licensee(s) and all Users shall establish a Protection Application Department with adequate manpower and skill set.

- 2) The protection system skill set is gained with experience, resolving various practical problems, case studies, close interaction with the relay manufacturers and field engineers.
- 3) Therefore, it is proposed that such people should be nurtured to have a long standing career growth in the Protection Application Department.
- 4) The STU shall Constitute a committee containing experts in the field of protection, indicated below for coordination and monitoring of protection functions for the entire grid, duly making the required studies for the protective relay settings.,
  - a. The Committee shall be headed by an Engineer not below the Rank of Chief Engineer Electrical, to conduct review meeting at least once in 3 months.
  - b. The Sub-Committee may be headed by the respective Superintending Engineers of the protection Circles who will conduct review meeting once in every month and bring the issues to the main Protection Committee for deliberation and decisions.

### **9.3.2 Relay Setting Calculations**

- 1) The protection group should do periodic relay setting calculations as and when necessitated by system configuration changes. A relay setting approval system should be in place.
- 2) Relay setting calculations also need to be revisited whenever the minor configuration or loading, changes in the system due to operational constraints. Feedback from the field/substations on the performance of the relay settings should be collected and settings should be reviewed and corrected if required.
- 3) Creating and maintaining data base of relay settings: Data regarding settings of relays in their network should be compiled by the CTU and STUs and furnished to the RLDC and SLDC respectively and a copy should also be submitted to RPC for maintaining the data base.

### **9.3.3 Co-ordination with system study group, system planning group and other Stakeholders**

- 1) STU, transmission licensee (s) and all Users shall develop a strong system study group with adequate manpower and skill-set that can carry out various system studies required for arriving at system related settings in protection system in addition to others studies.
- 2) The Protection Application Department should closely work in coordination with the STU, transmission licensee (s) and all Users' system study group, system planning group, the system operation group.

Wherever applicable, it should also co-ordinate and work with STU, transmission licensee (s) and all Users to arrive at the proper relay setting calculations for the system as a whole. The interface point relay setting calculations at CTU-STU, STU-DISCOMs, STU-GEN Companies, CTU-GEN Companies and also generator backup relay setting calculations related to system performance should be periodically reviewed and joint concurrence should be arrived.

The approved relay settings should be properly documented. Any un-resolved issues among the stakeholders should be taken up with the RPC and resolved.

#### **9.3.4 Simulation testing for checking Dependability and Security of Protection System for Critical lines and series compensated Lines**

The protection system for critical lines, all series compensated lines along with interconnected lines should be simulated for intended operation under normal and abnormal system conditions and tested for the dependability and security of Protection system. The RTDS facilities available in the country like at CPRI, POWERGRID and other places should be made use of by the STU, transmission licensee(s) and all Users of the Grid for this purpose.

The network model should be periodically updated with the system parameters, as and when network changes are incorporated.

#### **9.3.5 Adoption of Relay Setting and Functional verification of Setting at site**

- a. The Protection Application Department shall ensure through field testing group that the final relay settings are exactly adopted in the relays at field.
- b. There should be clear template for the setting adoption duly authorized and approved by the field testing in-charge.



- c. No relay setting in the field shall be changed without proper documentation and approval by the Protection Application Department.
- d. The Protection Application Department shall periodically verify the implemented setting at site through an audit process.
- e. Protection application department should also maintain a log of all protection operations. This record will be assets record and assist in future upgradation of protection system.

### **9.3.6 Storage and Management of Relay settings**

With the application of numerical relays, increased system size and volume of relay setting, associated data to be handled is enormous. It is recommended that utilities shall evolve proper storage and management mechanism (version control) for relay settings.

Along with the relay setting data, IED configuration file should also be stored and managed.

### **9.3.7 Root Cause Analysis of Major Protection Tripping (Multiple Element Outages) along with corrective & Improvement Measures**

- a. The routine tripping of transmission lines, transformers and generating units are generally analyzed by the field protection personnel. For every tripping, a trip report along with an associated DR and event logger file shall be generated. However, for major tripping in the system, it is recommended that the protection application department shall perform the root cause analysis of the event.
- b. The root cause analysis shall address the cause of a fault, any mal-operation or non-operation of relays, protection scheme etc.
- c. The root cause analysis shall identify corrective and improvement measures required in the relay setting, protection scheme or any other changes to ensure system security, reliability and dependability of the protection system.
- d. The Protection Application Department shall keep proper records of corrective and improvement actions taken.

### 9.3.8 Performance Indices: Dependability & Security of Protection System

The key performance indices should be calculated on yearly basis on the dependability and security of protection system as brought out in CBIP manual.

### 9.3.9 Periodic Protection Audit

Periodic audit of the protection system shall be ensured by the Protection Application Department.

The audit shall broadly cover the three important aspect of protection system, namely the philosophy, the setting, the healthiness of Fault Clearing System.

All the generating companies, STU, transmission licensee (s) and all Users shall co-operate with Regional Power Committee to conduct protection audits and shall attend to the defects/ shortcomings/ observations of such protection audit on the advice of RPC.

### 9.3.10 Regular Training and Certification

- i. The members of the Protection Application Department shall undergo regular training to enhance & update their skill sets.
- ii. The training modules shall consist of system studies, relaying applications, testing & commissioning of relays and Certification of protection system is strongly recommended.

## 9.4 Fault Clearance Time

From stability considerations, the maximum Fault Clearance Time for faults on any user's system directly connected to the Transmission System, or any faults on the Transmission System itself, shall be as specified in the CEA (Grid Standards) Regulations, 2010, amended from time to time as shown below:

Voltage Class	Target Clearance Time
400kV	100 milliseconds
220kV	160 milliseconds

For 110kV/66kV 350 msec is suggested instead of 160 msec in view of non-availability of carrier protection, zone-2 faults will get cleared after the set time delay. For 110kV/66kV lines, zone-2 time delay of 300 msec, if Local Breaker Backup (LBB) is available in the next bus and time delay of 200 msec if LBB is not available, may be adopted.

## 9.5 Generator Protection Requirements

All generating units and all associated electrical equipment of the generating company connected to the Transmission System shall be protected by adequate protection, as per the CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 and CBIP manual on Protection of Generators, Generator Transformers and 220kV and 400 kV networks vide publication 274 (revised), so that, the Transmission System does not suffer due to any disturbances originating at the generating unit. In case of inconsistency in protection aspects between CEA and CBIP, the provisions of CEA shall prevail.

## 9.6 Transmission Line Protection Requirements

Every HV/EHV/UHV line emanating from a generating station or a substation or a switching station shall necessarily have distance protection along with other protection as per the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and CBIP manual on Protection of Generators, Generator Transformers and 220kV and 400 kV networks vide publication 274 (revised).

(a) **400 kV lines:** - These lines shall have two main distance protections, viz. Main I and Main II with permissive inter-trip for remote earth fault. Three zone numerical non-switched distance protection with permissive inter-trip for accelerated tripping at remote end in case of zone 2 fault as Main I protection shall be provided. Main II protection shall be similar fast protection using direction comparison relay scheme. In addition to the above, single pole tripping and single shot single pole auto reclosing after an adjustable dead time shall be provided for single phase to ground faults. Three pole tripping and no auto reclose for multiphase faults. In addition to the above, back-up protection with OCR and EFR shall be provided.

(b) **220 kV lines:** - These lines shall have Main I and Main II protection which are of different manufacture or whose characteristics are based on different algorithms with permissive inter-trip for remote earth fault. Three zone

numerical non-switched distance protection, with permissible inter-trip shall be provided in Main I or Main II. DEF functionality shall be enabled for covering high resistive faults. The same shall be coordinated with zone protection and Auto reclose timings.

Single pole tripping and Single Shot Three Pole Auto-reclosing with adjustable dead-time shall be provided for the stability of the power system for single phase to ground faults. For multiphase faults three pole tripping with no auto reclose shall be provided.

- (c) **110/66kV lines:** - Three zone numerical switched distance protection with permissible inter-trip for accelerated tripping at the remote end in case of zone 2 protection shall be provided as main protection. The back-up will be directional three-phase over current and earth fault protection.
- (d) **Differential protection for short transmission lines less than 10 km distance:** The recommendation of SRPC to provide differential protection using fiber optic/any other reliable communication channel between the two ends as one of the main protection and distance protection with reduced zone one setting as main two protections for short 220kV lines less than 10 Km line and 110/66kV lines of length less than 5 Km is to be adopted by STU to have a reliable protection for EHV lines.
- (e) **Continuity of ground wires:** - Ground wires help to reduce the apparent tower footing resistance. It is to be noted that all HV/EHV and UHV lines need one or more than one ground wire at a certain height above the conductor to provide the desired shielding. The continuity of such ground wires above the entire length of the transmission lines is necessary to have effective line protection. The tower footing impedance parameters are required to be kept as low as practically feasible and may need special measures like counter poles and other known methods of reducing the footing impedance.
- (f) **Busbar Protection:** - Adequate busbar protection for the station busbar sections in all 400 kV and 220 kV class substations shall be provided.
- (g) **Local Breaker Backup Protection (LBB):** - In the event of any circuit breaker failing to trip on receipt of trip command from protective relays, all circuit breakers connected to the bus section to which the faulty circuit breaker is connected are required to be tripped with a time delay of 200milli seconds.
- (h) **Recommendations for provisions of auto-reclosing.**

Single phase high speed auto-re closure (HSAR) at 400 kV and 220 kV lines including the lines emanating from Generating Stations with a dead time of 1000 milli second is recommended for adoption.

**Note:** Recommended methodology for relay settings for uncompensated and compensated lines, use of system studies to analyse distance relay behaviour, maintaining operation of power station auxiliary system of nuclear power plants, coordination between system study group and protection engineers and simulation studies are presented in the annexure-VII & VIII onwards which shall be referred to by the STU and Users.

General Information of the substation details for facilitating protection audit which should indicate the details of instrument transformers, availability of Protection System, substation protection and monitoring equipment, DC supply, line protection, transformer protection and reactor protection as shown in annexure -IX.

The check list to enable audit of practices followed in protection application & criteria used for setting calculations in 220kV, 400kV & 765kV substations shall be used as per the annexure -XI.

## 9.7 Power Transformer Protection requirements

- a. **400 kV and 220 kV class Power Transformers:** - These shall be provided with differential protection, restricted earth fault protection, over flux protection, Bucholtz protection, PRV, oil and winding temperature protection along with IDMT over current protection and earth fault protection as backup protection for HV & LV and non-directional over current protection for tertiary winding. Over fluxing relays shall be provided on transformers having rating more than 100MVA capacity. Appropriate fire protection for all power transformers as per CBIP/CEA specifications shall be provided.
  
- b. **110 kV and 66 kV class power transformers:** These shall have differential protection, restricted earth fault protection, Bucholtz protection, and winding/oil temperature protection. They shall also have directional over current as back-up protection with an instantaneous element. In addition to the above, pressure relief valves/diaphragms shall be provided for all the power transformers. Appropriate fire protection for all the power transformers as per CBIP/CEA specifications shall be provided.

- c. **Distribution System:** For smaller transformers of HV class on the distribution system, differential protection shall be provided for 5 MVA capacities and above, along with back-up time lag over current and earth fault protection with directional feature for parallel operation. Transformers of capacity less than 5 MVA shall be protected by time lag over current, earth fault and instantaneous restricted earth fault relays. In addition, all such transformers shall be provided with gas operated relays, winding and oil temperature protection.
- d. **Distribution Lines:** All the 33 kV and 11 kV lines at Connection Points/ Interface Points shall be provided with a minimum of over current and earth fault relays.
- e. **Plain Radial Feeders:** Non-directional over current and earth fault relays with suitable settings to obtain discrimination between adjacent relay settings.
- f. **Parallel/Ring Feeders:** Directional time lag over current and earth fault relay.
- g. **Inadvertent Flow:** - When two systems are operating in parallel with floating tie-line, it may not be possible to have tie-line absolutely floating because of dynamics of network parameters and there will be a flow of energy from one system to another system. Such inadvertent flow shall be accounted for the purpose of commercial billing.

## 9.8 Metering

Meters shall be provided as specified in the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 as amended from time to time.

## SECTION- 10

### Miscellaneous

#### Issue of orders and practice directions

Subject to the provisions of the Electricity Act, 2003 and these Regulations, the Commission may, from time to time, issue orders and practice directions with regard to the implementation of the Regulations and procedures to be followed.

#### 10.1 Power to remove difficulties

- (i) In case of any difficulty in giving effect to any of the provisions of these regulations, the Commission may by general or special order, direct the Open Access Customers, generators and the licensees to take suitable action, not being inconsistent with the provisions of the Electricity Act, 2003, which appears to the Commission to be necessary or expedient for the purpose of removing the difficulty.
- (ii) The Open Access Customers, generators and the licensees may make an application to the Commission and seek suitable orders to remove any difficulties that may arise in implementation of these Regulations.

#### 10.2 Power to amend:

The Commission may from time to time add, vary, alter, modify or amend any provisions of these Regulations after following the necessary procedures.

The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing the parties likely to be affected by grant of relaxation, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

By order of the Commission

**Secretary**  
**KARNATAKA ELECTRICITY REGULATORY COMMISSION**

## SITE RESPONSIBILITY SCHEDULE

Name of Power Station / Sub – Station:

Site Owner:

Site Manager:

Tel. Number:

Fax Number:

Item of Plant / Apparatus	Plant Owner	Safety responsibility	Control responsibility	Operation responsibility	Maintenance responsibility	remarks
____KV Switchyard						
All equipment including bus bars feeders						
Generating units						



## ANNEXURE-II

## INCIDENT REPORTING

First report

Date: \_\_\_\_\_

Time: \_\_\_\_\_

S.N	Item	Details
1	Date and time of incident	
2	Location of incident	
3	Type of incident	
4	System parameters before the incident (voltage, frequency, flows, generation etc.)	
5	Relay indications received and performance of protection	
6	Damage to equipment	
7	Supplies interrupted and duration, if applicable	
8	Amount of generation lost, if applicable	
9	Possibility of alternate supply arrangement	
10	Estimate of time to return to service	
11	Cause of incident	
12	Any other relevant information and remedial action taken	
13	Recommendations for future improvement / repeat incident	
14	Name of the organization	

**Requisition for Line Clear Permit (Clause No. 7.7 )**

Date .....

Time .....

I Mr/Ms. ----- request Line Clear Permit on the following HT/EHT line/equipment

**HV/EHV Apparatus/Line Identification:**

**Details of works to be carried out:**

**Estimated time required for completion:**

Name and Signature .....

.....  
 (Requesting Safety Coordinator) (In-charge of crew)

Designation.....

Date.....

(For use in substation from where Line Clear Permit will be issued)

- (a) Line Clear Permit issued: Yes/No
- (b) Number and date of issue (Code No.):
- (c) Time of issue:
- (d) Date & time of return:
- (e) Remarks: see check list LCP - H

**Receipt of LCP**

I have received confirmation from ..... (Name of issuing safety coordinator) at .....(location) that the safety precautions have been established and the instructions will not be issued at his location for their removal until his LCP-H is cancelled.

Name and Signature.....

(Requesting safety coordinator)

In charge of the crew at .....(time) on .....(date)

(To be printed on the reverse of LCP-H: Checklist of Line Clear Permit)

**Conditions:**

- (a) This permit is valid only for working in the feeder/equipment mentioned herein and not in any other feeder/equipment.
- (b) Only authorised persons are allowed to work on feeders/equipment for which the permit has been issued.
- (c) Works as per requisition only should be carried out.
- (d) Before touching any part of the feeder/equipment, the same should be earthed at two points on either side through standard discharge rods connected with good earth.

Temporary earthing may only be removed after completion of all works and after all the men have come down from the feeder/equipment.

(e) Work should be so planned that the Line Clear is returned before or at the time indicated. If unavoidable delay is anticipated, advance information should be given to the location from where the Line Clear is issued.

(f) Before return of the Line Clear, it should be ensured that all the men, materials, tools/tackles etc., on the line have returned and reported that all temporary earths are removed. There should also be a check on the material, tools and plant issued for the work to ensure that nothing is left behind on the line or equipment.

(g) Only authorised persons should return Line Clear.

(h) In case the Line Clear cannot be returned in person, the same may be returned to the Line Clear Issuing Authority over telephone by naming the code words assigned and the telephone number which is used for naming the code words assigned. In case two or more different code words are issued to the two or more persons in whose favour the permit is given, those persons must jointly return the Line Clear by naming their own code words. The Line Clear Return will not be deemed to be accepted unless returned by all these persons.

(i) The Line Clear issuing authority should go over the checklist of Line Clear Return before accepting it.

(j) If Line clear is returned over telephone, the Line Clear return form duly filled and signed should be sent to the Line Clear issuing authority by post immediately for record.

(k) Control person should keep all the required data of LCP issued and LCR received. He should monitor and keep specific note in the log sheet when more than one LCP are issued on same line/ equipment/bay along with code words.

<<<<<<>>>>>>

**Check list for Line Clear Permit and Line Clear Permit (Clause No. 7.7)**

LCP-H Number.....  
Dated.....Time.....

**Check List of the Line Clear Permit:**

- (a) Name of location for which line clear is issued
- (b) Reference and authority requisitioning Line Clear: (Indicate original LCP-G number including suffix and prefix)
- (c) Identity of HV Apparatus
- (d) Sources from which the line/equipment is charged
- (e) Number/name of circuit breaker/isolating switch open at each of above sources
- (f) Whether confirmed that the line is disconnected at both ends
- (g) Whether line is earthed at both ends
- (h) Whether circuit breaker truck removed in case of indoor switchgear controlling the feeder/equipment for which line clear is given
- (i) Whether fuses of control supply voltage of the circuit breaker/isolating switches controlling the feeder/equipment for which line clear is given are removed and kept in safe custody
- (j) Time of issue of Line Clear Permit and LCP-G No.
- (k) Name of requesting safety coordinator on whom LCP-G is issued
- (l) Approximate time for returning LCP-G as ascertained from the requesting coordinator

Name and Signature.....  
(Issuing Safety Coordinator)

Designation.....

**Line Clear Permit**

LCP - G No..... I, Mr/Ms.----- (Issuing Safety Coordinator) do hereby issue permission to Mr/Ms.----- (Requesting Safety Coordinator) for carrying out works as per requisition No.....date.....time .....

The EHV/ HV Line/equipment herein described is declared safe. The permission is subject to the conditions given in LCP-F.

Name and Signature.....  
(Person issuing Line Clear Permit)

Designation.....

<<<<<<>>>>>>

**Annexure V**

**Line Clear Return (Clause No.7.7 )**

LCP - I Number..... Date  
.....Time.....

LCP-H No..... Dated..... I, Mr/Ms. ----- hereby return the LCP No. -----at -  
----- (time) for the following HT/EHT Line/Apparatus.

I declare that all the crew who were sent on work have been withdrawn, temporary earth(s) removed, all repair tools and materials checked and the feeders/equipments mentioned below are safe to be energised.

- (a) HV/EHV Apparatus/Line Identification:
- (b) Safety precaution no longer required:
- (c) Isolation [State locations and each point of isolation indicating means by which isolation was achieved]
- (d) Earthing [State location at which earthing was established and identify each point of earthing]
- (e) Details of work done

**Check list to be ticked off:**

- (a) Whether all men withdrawn: Yes/No
- (b) Whether all temporary earth removed: Yes/No
- (c) Whether materials, tools and plant used in the work have been checked: Yes/No
- (d) Code Number (If used when Line Clear is returned over phone) -----

Name and Signature.....  
(Requesting Safety Coordinator)

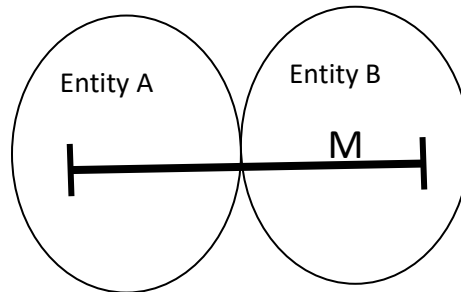
Designation.....  
In-charge of Crew -----  
(Designation)

<<<<<<>>>>>>>

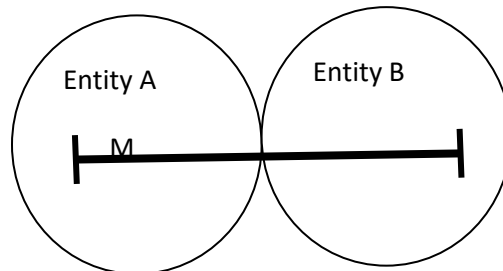
Annexure VI

**Payment for Reactive Energy Exchanges on Lines Owned By Individual Entities (Clause No. 8.6.6)**

**Case- 1:** Interconnecting line owned by Entity – A  
Metering Point: Substation of Entity – B



**Case- 2:** Interconnecting line owned by Entity – B  
Metering Point: Substation of Entity – A

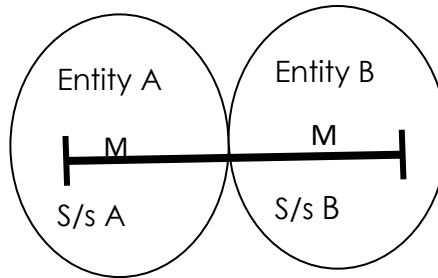


Entity B pays to Entity A for

- (i) Net VARh received from Entity A while voltage is below 97%
- (ii) Net VARh supplied to Entity A while voltage is above 103%

Note: Net VARh and net payment may be positive or negative

**Case- 3:** Interconnecting line jointly owned by Entity – A & B  
 Metering Point: Substations of Entity - A & Entity - B



Net VARh exported from S/S-A, while voltage < 97% = X1  
 Net VARh exported from S/S-A, while voltage > 103% = X2  
 Net VARh imported at S/S-B, while voltage < 97% = X3  
 Net VARh imported at S/S-B, while voltage > 103% = X4

- (i) State-B pays to State-A for X1 or X3, whichever is smaller in magnitude, and
- (ii) State-A pays to State-B for X2 or X4, whichever is smaller in magnitude.

Note:

1. Net VARh and net payment may be positive or negative.
2. In case X1 is positive and X3 is negative, or vice-versa, there would be no payment under (i) above.
2. In case X2 is positive and X4 is negative, or vice-versa, there would be no payment under (ii) above.

<<<<<<>>>>>>>>

**RECOMMENDED METHODOLOGY FOR RELAY SETTINGS OF UNCOMPENSATED TRANSMISSION LINES****1. ZONE-1 REACH SETTING:**

Zone-1: To be set to cover 80% of protected line length. Set zero sequence compensation factor  $K_N$  as  $(Z_0 - Z_1) / 3Z_1$ .

Where:

$Z_1$  = Positive sequence impedance of the protected line

$Z_0$  = Zero sequence impedance of the protected line

Note: With this setting, the relay may overreach when parallel circuit is open and grounded at both ends. This risk is considered acceptable.

**2. ZONE-2 REACH SETTING:**

Zone-2: To be set to cover the next 20% of length of principal line section plus 50% of shorter adjacent line to take care of under reaching due to mutual coupling effect. Set  $K_N$  as  $(Z_0 - Z_1) / 3Z_1$ .

Sometimes impedance so selected might enter the next voltage level. However, unselectivity in the Zone-2 grading is generally not to be expected when in-feeds exist at the remote sub-station as they reduce the overreach considerably.

This holds good for majority of the cases, however, for certain cases, where in-feed from other feeder at the local bus is not significant, Zone-2 of remote end relay may see the fault at lower voltage level. Care has to be taken for all such cases by suitable time delay.

**3. ZONE-3 REACH SETTING:**

Zone-3 distance protection can offer time-delayed remote back-up protection for an adjacent transmission circuit. To achieve this, Zone-3 distance elements must be set according to the following criteria where possible.

Zone-3 to be set to cover the next 20% of the length of principal line section plus 100% of longest adjacent line.



However, in such case where Zone-3 reach is set to enter into next lower voltage level, Zone-3 timing shall be coordinated with the back-up protection (Directional over current and earth fault relay) of power transformer. Where such coordination cannot be realized, it is recommended to carry out simulation studies for relay reach and time coordination and suitable solution may be devised. Some of the typical solution can be application of back up distance protection for power transformer, duplicated protection for downstream 220kV feeders or special protection scheme logic. Similar issues, if encountered for Zone-2 reach setting, should also be addressed in the above manner.

#### 4. **RESISTIVE REACH SETTING**

For phase to ground faults, resistive reach should be set to give maximum coverage considering fault resistance, arc resistance & tower footing resistance. It has been considered that ground fault would not be responsive to line loading.

For Zone-1 resistive reach, attention has to be given to any limitations indicated by manufacturer in respect of resistive setting vis-a-vis reactance setting to avoid overreach due to remote in-feed. *It is recommended to study the impact of remote end in-feed for expected power flow and fault resistance on the extent of overreach. This is particularly important for short lines.*

In case of phase to phase fault, resistive reach should be set to provide coverage against all types of anticipated phase to phase faults subject to check of possibility against load point encroachment considering minimum expected voltage and maximum load expected during short time emergency system condition.

It is recommended that all the distance relays should have quadrilateral / polygon characteristic. For relays having Mho characteristic, it is desirable to have load encroachment prevention characteristic or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a line during emergency system condition, following criteria may be considered for deciding load point encroachment:

- Maximum load current ( $I_{max}$ ) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15 minutes rating of the transmission facility).
- Minimum voltage ( $V_{min}$ ) to be considered as 0.85pu (85%).

Due to in-feeds, the apparent fault resistance seen by relay is several times the actual value. This should be kept in mind while arriving at resistive reach setting for Zone-2 and Zone-3.

**5. ZONE-2 TIMER SETTING:**

A Zone-2 timing of 0.4 seconds (considering LBB time of 200mSec, CB open time of 60ms, resetting time of 30ms and safety margin of 60ms) is recommended. However, if a long line is followed by a short line, then a higher setting (typically 0.6second) may be adopted on long line to avoid indiscriminate tripping through Zone-2 operation on both lines.

For special cases, following shall be the guiding philosophy:

Since Zone-2 distance protection is set to overreach the circuit it is intended to protect, it will also be responsive to faults within adjacent power system circuit. For this reason the time delay for Zone-2 back-up protection must be set to coordinate with clearance of adjacent circuit faults, within reach, by the intended main protection or by breaker fail protection.

The following formula would be the basis for determining the minimum acceptable Zone-2 time setting:

$$t_{Z2} > t_{MA} + t_{CB} + t_{Z2reset} + t_s$$

Where:

$t_{Z2}$  = Required Zone-2 time delay

$t_{MA}$  = Operating time of slowest adjacent circuit main protection or Circuit Local back-up for faults within Zone-2 reach

$t_{CB}$  = Associated adjacent circuit breaker clearance time

$t_{Z2reset}$  = Resetting time of Zone-2 impedance element with load current present

$t_s$  = Safety margin for tolerance (e.g. 50 to 100ms)

Unequal lengths of transmission circuit can make it difficult to meet the Zone-2 secondary reach setting criterion. In such cases it will be necessary to co-ordinate Zone-2 with longer time delay. The time  $t_{MA}$  in equation must be the adjacent circuit Zone-2 protection operating time.

**6. ZONE-3 TIMER SETTING**

Zone-3 timer should be set so as to provide discrimination with the operating time of relays provided in subsequent sections with which Zone-3 reach of relay being set, overlaps. Typical recommended Zone-3 time is 0.8 to 1.0 second.

For Special cases, where co-ordination between long and short lines is required, following formula would be the basis for determining the minimum acceptable Zone-3 time setting:

$$t_{Z3} > t_{MA} + t_{CB} + t_{Z3reset} + t_s \quad \text{Where:}$$

$t_{Z3}$  = Required Zone-3 time delay

$t_{MA}$  = Operating time of slowest adjacent circuit local back-up protection

$t_{CB}$  = Associated adjacent circuit breaker clearance time

$t_{Z3reset}$  = Resetting time of Zone-3 impedance element with load current present

$t_s$  = Safety margin for tolerance (e.g. 50 to 100milliseconds)

## **7. LOAD IMPEDANCE ENCROACHMENT**

With the extended Zone-3 reach settings, that may be required to address the many under reaching factors already considered, load impedance encroachment is a significant risk to long lines of an interconnected power system. Not only the minimum load impedance under expected modes of system operation be considered in risk assessment, but also the minimum impedance that might be sustained for seconds or minutes during abnormal or emergency system conditions. Failure to do so could jeopardize power system security.

Ideal solution to tackle load encroachment may be based on the use of blinders or by suitably setting the resistive reach of specially shaped impedance elements or by use of polygon type impedance elements.

It is recommended that all the distance relays should have quadrilateral / polygon characteristic. For relays having Mho characteristics, it is desirable to have load encroachment prevention characteristics or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a feeder during emergency system condition, following criteria may be considered for deciding resistive reach / blinder setting to prevent load point encroachment:

- Maximum load current ( $I_{max}$ ) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating ( the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15 minutes rating of the transmission facility).
- Minimum voltage ( $V_{min}$ ) to be considered as 0.85pu (85%).
- For setting angle for load blinder, a value of 30 degree may be adequate in most cases.

For high resistive earth fault where impedance locus lies in the Blinder zone, fault clearance shall be provided by the back-up directional earth fault relay.

## **8. ZONE-4 SUBSTATION LOCAL BACKUP PROTECTION SETTINGS**

Zone-3 distance protection is usually targeted to provide only remote back-up protection. In such a case, the distance relay may be provided with an additional zone of reverse-looking protection (e.g. Zone-4) to offer substation-local back-up protection. The criterion for setting Zone-4 reverse reach would be as under.

- The Zone-4 reverse reach must adequately cover expected levels of apparent bus bar fault resistance, when allowing for multiple in feeds from other circuits. For this reason, its resistive reach setting is to be kept identical to Zone-3 resistive reach setting.

With a reverse reach setting of less than the Zone-1 reach of distance protection for the shortest line connected to the local bus bar, the Zone-4 time delay would only need to co-ordinate with bus bar main protection fault clearance and with Zone-1 fault clearance for lines out of the same substation. For this reason this can be set according to the Zone-3 time.

**9. USE OF SYSTEM STUDIES TO ANALYSE DISTANCE RELAY BEHAVIOUR**

Often during system disturbance conditions, due to tripping of one or more trunk lines, some lines get overloaded and the system voltage drops. During such conditions the back-up distance elements may become susceptible to operation due to encroachment of impedance locus in to the distance relay characteristic.

While the ohmic characteristic of a distance relay is independent of voltage, the load is not generally constant-impedance. The apparent impedance presented to a distance relay, as the load voltage varies, will depend on the voltage characteristic of the load. If the low voltage situation resulted from the loss of one or more transmission lines or generating units, there may be a substantial change in the real and reactive power flow through the line in question. The combination of low voltage and worsened phase angle may cause a long set relay to operate undesirably either on steady state basis, or in response to recoverable swings related to the initiating event.

The apparent impedance seen by the relay is affected by in-feeds, mutual coupling and therefore the behavior of distance relay during various system condition needs to be studied wherever necessary to achieve proper relay coordination.

It is desirable and hence recommended that system studies are conducted using computer-aided tools to assess the security of protection by finding out trajectory of impedance in various zones of distance relay under abnormal or emergency system condition on case-to-case basis particularly for critical lines / corridors.

In addition, the settings must be fine-tuned, simulating faults using Real Time Digital Simulator on case-to-case basis particularly for critical lines / corridors.

Such facilities available at CPRI, POWERGRID or elsewhere in the country should be used for protection related studies.

**10. DIRECTIONAL PHASE OVER CURRENT PROTECTION**

Directional phase over current relays are still being used as back-up protection for 220kV transmission lines by many utilities. In view of time coordination issues and increased fault clearance time in the event of failure of main distance protection, *it is recommended that for all 220kV lines also main-1 and main-2 protections similar to 400kV lines be provided.*

**11. DIRECTIONAL GROUND OVER CURRENT PROTECTION (DEF) SETTINGS**

Normally this protection is applied as a supplement to main protection when ground fault currents may be lower than the threshold of phase over current protection. It might also be applied as main protection for high resistance faults.

The ground over current threshold should be set to ensure detection of all ground faults, but above any continuous residual current under normal system operation. Continuous residual current may arise because of following:

- Unbalanced series impedances of untransposed transmission circuits
- Unbalanced shunt capacitance of transmission circuits.
- Third harmonic current circulation.

Various types of directional elements may be employed to control operation of ground over current (zero sequence over current) protection response. The most common approach is to employ Phase angle difference between Zero sequence voltage and current, since the relaying signals can easily be derived by summing phase current signals and by summing phase voltage signals from a suitable voltage transformer.

However, this method is not suitable for some applications where transmission lines terminated at different substations, run partially in parallel. In such cases following type of directional control is recommended to be used for the directional earth fault relay.

Relative phase of negative sequence voltage and current

To ensure proper coordination, operating time must be set according to following criteria:

The DEF protection should not operate when the circuit local backup protection of remote end clears a fault in an adjacent circuit i.e. DEF should be coordinated with the remote end LBB.

## **12. POWER SWING BLOCKING FUNCTION**

While the power-swing protection philosophy is simple, it is often difficult to implement it in a large power system because of the complexity of the system and the different operating conditions that must be studied. There are a number of options one can select in implementing power-swing protection in their system. Designing the power system protection to avoid or preclude cascade tripping is a requirement of modern day power system. Below we list two possible options:

### **12.1. Block all Zones except Zone-1**

This application applies a blocking signal to the higher impedance zones of distance relay and allows Zone 1 to trip if the swing enters its operating characteristic. Breaker application is also a consideration when tripping during a power swing. A subset of this application is to block the Zone 2 and higher impedance zones for a preset time (Unblock time delay) and allow a trip if the detection relays do not reset.

In this application, if the swing enters Zone 1, a trip is issued, assuming that the swing impedance entering the Zone-1 characteristic is indicative of loss of synchronism.

However, a major disadvantage associated with this philosophy is that indiscriminate line tripping can take place, even for recoverable power swings and risk of damage to breaker.

### 12.2. Block All Zones and Trip with Out of Step (OOS) Function

This application applies a blocking signal to all distance relay zones and order tripping if the power swing is unstable using the OOS function (function built in modern distance relays or as a standalone relay). This application is the recommended approach since a controlled separation of the power system can be achieved at preselected network locations. Tripping after the swing is well past the 180 degree position is the recommended option from CB operation point of view.

Normally all relay are having Power swing Un-block timer which unblocks on very slow power swing condition (when impedance locus stays within a zone for a long duration). Typically the Power swing un-blocking time setting is 2sec.

However, on detection of a line fault, the relay has to be de-blocked.

### 12.3. Placement of OOS trip Systems

Out of step tripping protection (Standalone relay or built-in function of Main relay) shall be provided on all the selected lines. The locations where it is desired to split the system on out of step condition shall be decided based on system studies.

*The selection of network locations for placement of OOS systems can best be obtained through transient stability studies covering many possible operating conditions.*

*Till such studies are carried out and Out-of-Step protection is enabled on all identified lines, it is recommended to continue with the existing practice of Non-Blocking of Zone-I on Power Swing as mentioned under Option-12.1 above. However, it should be remembered that with this practice the line might trip for a recoverable swing and it is not good to breakers.*

*It is strongly recommended that, the required studies must be carried out at the earliest possible time (within a timeframe of one year) to exercise the option-12.2 & 12.3 above.*

## 13. LINE OVERVOLTAGE PROTECTION

**FOR 400kV LINES:** Low set stage (Stage-I) may be set in the range of 110% - 112% (typically 110%) with a time delay of 5 seconds. High set stage (Stage-II) may be set in the range 140% - 150% with a time delay of 100milliseconds.

**FOR 765kV LINES:** Low set stage (Stage-I) may be set in the range of 106% - 109% (typically 108%) with a time delay of 5 seconds. High set stage (Stage-II) may be set in the range 140% - 150% with a time delay of 100milliseconds.

However, for over voltage Stage-I protection, a time grading of 1 to 3 seconds may be provided between overvoltage relays of double circuit lines. Grading on overvoltage tripping for various lines emanating from a station may be considered and same can be achieved using voltage as well as time grading. Longest timed delay should be checked with expected operating time of Over-fluxing relay of the transformer to ensure disconnection of line before tripping of transformer.

It is desirable to have Drop-off to pick-up ratio of overvoltage relay better than 97% (Considering limitation of various manufacturers relay on this aspect).

**14. LINE DIFFERENTIAL PROTECTION**

Many transmission lines are now having OPGW or separate optic fiber laid for the communication. Wherever such facilities are available, it is recommended to have the line differential protection as Main-I protection with distance protection as backup (built-in Main relay or standalone). Main-II protection shall continue to be distance protection. For cables and composite lines, line differential protection with built in distance back up shall be applied as Main-I protection and distance relay as Main-II protection. Auto-reclose shall be blocked for faults in the cables.

**15. MAINTAINING OPERATION OF POWER STATION AUXILIARY SYSTEM OF NUCLEAR POWER PLANTS:**

Depression of power supply voltages for auxiliary plant in some generating stations may reduce the station output. Maintenance of full generation output may be a critical power system security factor. In the case of nuclear plant, auxiliary power supplies are also a major factor in providing full nuclear plant safety and security.

The potential loss of system generation or the potential challenges to nuclear plant safety systems may be factors which will dictate the longest acceptable clearance times for transmission circuit faults in the vicinity of a power station. This should be further taken up with utilities of nuclear plants and this and any other requirements should be understood and addressed.

**16. COORDINATION BETWEEN SYSTEM STUDY GROUP AND PROTECTION ENGINEERS**

For quite a few cases where system behavior issues are involved it is recommended that power system study group is associated with the protection engineers. For example power swing locus, out of step tripping locations, faults withstands capability, zone2 and zone3 overlap reach settings calculations are areas where system study group role is critical/essential.

\*\*\*\*\*

**RECOMMENDED METHODOLOGY FOR RELAY SETTINGS OF SERIES COMPENSATED TRANSMISSION LINES:**

Following phenomenon associated with the protection of Series compensated lines require special attention:

**1) VOLTAGE AND CURRENT INVERSION****1.1. Voltage inversion on Series Compensated line:**

In this case the voltage at the relay point reverses its direction. This phenomenon is commonly called as voltage inversion. Voltage inversion causes false decision in conventional directional relays. Special measures must be taken in the distance relays to guard against this phenomenon.

**1.2. Current inversion on Series Compensated line:**

Fault current will lead source voltage by 90 degrees if  $X_C > X_S + X_{L1}$ . Current inversion causes a false directional decision of distance relays (voltage memories do not help in this case). [Here  $X_C$  is reactance of series capacitor,  $X_S$  is source reactance and  $X_{L1}$  is reactance of the line]

Current inversion influences operation of distance relays and therefore they cannot be applied without additional logic for the protection of series compensated lines when possibility of current inversion exists. Performance of directional comparison protections, based on residual (zero sequence) and negative sequence currents are also affected by current inversion. *It is therefore, recommended to check the possibility of current inversion through system studies at the planning stage itself.*

**2) LOW FREQUENCY TRANSIENTS**

Series capacitors introduce oscillations in currents and voltages in the power systems, which are not common in non-compensated systems. These oscillations have frequencies lower than the rated system frequency and may cause delayed increase of fault currents, delayed operation of spark gaps as well as delayed operation of protective relays.

Low frequency transients have in general no significant influence on operation of line current differential protection as well as on phase comparison protection. However, they may significantly influence the correct operation of distance protection in two ways:

- They increase the operating time of distance protection, which may in turn influence negatively the system stability
- They may cause overreaching of instantaneous distance protection zones and this way result in unnecessary tripping on series compensated lines.

It is recommended to reduce the reach setting by a safety factor ( $K_s$ ) to take care of possible overreach due to low frequency oscillations.



**3) MOV INFLUENCE AND APPARENT IMPEDANCE**

Metal Oxide Varistors (MOV) are used for capacitor over-voltage protection. In contrast to spark gaps, MOVs carry current when the instantaneous voltage drop across the capacitor becomes higher than the protective voltage level in each half-cycle. Extensive studies have been done by Bonneville Power Administration in USA to arrive at a non-linear equivalent circuit for a series connected capacitor using an MOV. The composite impedance depends on total fault current and protection factor  $k_p$ .

The latter is defined by equation.

$$k_p = \frac{U_{MOV}}{U_{NC}}$$

Where  $U_{MOV}$  is voltage at which MOV starts to conduct theoretically and  $U_{NC}$  is voltage across the series capacitor when carrying its rated nominal current

This should be considered while relay setting.

**4) IMPACT OF SC ON PROTECTIVE RELAYS OF ADJACENT LINES**

Voltage inversion is not limited only to the buses and to the relay points close to the series compensated line. It can spread deep into the network and this way influence the selection of protection devices (mostly distance relays) at remote ends of the lines adjacent to the series compensated circuit, and sometimes even deeper in the network. Estimation of their influence on performances of existing distance relays of adjacent lines must be studied. In the study, it is necessary to consider cases with higher fault resistances, for which spark gaps or MOVs on series capacitors will not conduct at all.

If voltage inversion is found to occur, it may be necessary to replace the existing distance relays in those lines with distance relays that are designed to guard against this phenomenon.

**5) MULTI CIRCUIT LINES**

Two parallel power lines both series compensated running close to each other and ending at the same busbar at both ends can cause some additional challenges for distance protection due to the zero sequence mutual impedance. The current reversal phenomenon can also raise problems from the protection point of view, particularly when the power lines are relatively short and when permissive overreach schemes are used.

**Influence of zero sequence mutual impedance**

Zero sequence mutual impedance  $Z_{M0}$  will not significantly influence the operation of distance protection as long as both circuits are operating in parallel and all precautions related to settings of distance protection on series compensated line have been considered. Influence of parallel line switched off & earthed at both ends, on the operation of distance protection on single operating circuit is well known.

The presence of series capacitor additionally exaggerates the effect of zero sequence mutual impedance between two circuits. The effect of zero sequence mutual impedance on possible overreaching of distance relays is increased further compared to case of non-compensated lines. This is because while the series capacitor will compensate self-impedance of the zero sequence network the mutual impedance will be same as in the case of non-compensated double circuit lines. The reach of under reaching distance protection zone 1 for phase to earth measuring loops must further be reduced for such operating conditions.

Zero sequence mutual impedance may also disturb the correct operation of distance protection for external evolving faults during auto reclosing, when one circuit is disconnected in one phase and runs in parallel during dead time of single pole auto reclosing cycle. *It is recommended to study all such operating conditions by dynamic simulations in order to fine tune settings of distance relays.*

#### **6) DIRECTIONAL RESIDUAL OVERCURRENT PROTECTION**

All basic application considerations, characteristic for directional residual over-current protection on normal power lines apply also to series compensated lines with following additions. Low fault currents are characteristic of high resistive faults. This means that the fault currents may not be enough to cause voltage drops on series capacitors that would be sufficient to start their over-voltage protection. Spark gaps may not flash over in most cases, and metal oxide varistors (MOVs) may not conduct any significant current. Series capacitors may remain fully inserted during high resistive earth faults.

##### **Local end directional residual OC protection:**

The directional relay operates always correctly for reverse faults. VT located between bus and capacitor generally does not influence directional measurement. But in case VT is located between line and capacitor it may influence correct operation: While reverse faults are detected correctly the forward operation is dependent on system conditions. Additional zero sequence source impedance can be added into relay circuits to secure correct directional measurement.

##### **Remote end directional residual OC protection:**

In this case the current can be reduced to extremely low values due to low zero sequence impedance at capacitor end. Further the measured residual voltage can be reduced to very low value due to low zero sequence source impedance and/or low zero sequence current. Zero sequence current inversion may occur at the capacitor end (dependent on fault position). Directional negative sequence OC protection too may face very similar conditions.

Adaptive application of both the above OC protection principles can be considered wherever required to get the desired result.

**7) DISTANCE PROTECTION SETTINGS GUIDELINES**

- Basic criteria applied for Z1 & Z2 reach settings are :
  - Zone-1 should never overreach for the fault at remote bus
  - Zone-2 should never under reach for fault on protected line
  - **Permissive overreach (POR) schemes are usually applied**

Distance protection Zone 1 shall be set to

Zone-1 is set usually at 80% of  $X_{Z1} = K_s \cdot (X_{11} + X_{12} - X_C)$  Where  $X_{11}$  is reactance between CT and capacitor and  $X_{12}$  is reactance between capacitor and remote end Bus,  $X_C$  is reactance of capacitor and  $K_s$  is safety factor to prevent possible overreaching due to low frequency (sub-harmonic) oscillations. These setting guidelines are applicable when VT is installed on the bus side of the capacitor. It is possible to remove  $X_C$  from the above equation in case VT is installed on line side, but it is still necessary to consider the safety factor.

- Alternatively, Zone-1 is set at 80% of line impedance with a time delay of **100 millisecond**. POR Communication scheme logic is modified such that relay trips instantaneously in Zone-1 on carrier receive. ( For remote end relay of the line looking into series capacitor)
- Zone-2 is set to 120 % of uncompensated line impedance for single circuit line. For double circuit lines, special considerations are mentioned at Section B-5 above.
- Phase locked voltage memory is used to cope with the voltage inversion. Alternatively, an intentional time delay may be applied to overcome directionality problems related to voltage inversion.
- Special consideration may be required in over voltage stage-I (low set) trip setting for series compensated double circuit lines. It has been experienced that in case of tripping of a heavily loaded circuit, other circuit experience sudden voltage rise due to load transfer. To prevent tripping of other circuit on such cases, over-voltage stage-I setting for series compensated double circuit lines may be kept higher at 113%.

**8) SIMULATION STUDIES**

System studies, Use of real Time digital simulators, Tests using EMTP files are very important when applying protections for series compensated lines. It is recommended to carry out such studies specific to each line.

\*\*\*\*\*

- General Information:**
1. Name of Sub-station
  2. Date of first commissioning
  3. Type of Bus Switching Scheme:
  4. Whether SLD collected or Not:

- Audit Team:**
1. ....
  2. ....
  3. ....

**(1) Instrument Transformer** ( To be filled for each one of them)

**A. Current transformer (C T)**

- a. Location of CT
- b. Date of CT ratio Test Testing
- c. Test Results

		Core I	Core II	Core III	Core IV	Core V	Core VI
i	Ratio Adopted						
ii	Ratio measured						
iii	error calculated						
	Knee point voltage						

**B. Capacitive voltage transformer (C V T)**

<b>1</b>	<b>Location of CVT</b>			
a	Date of Testing			
b	CVT ratio Test			
		Core I	Core II	Core III
i	Ratio Adopted			
ii	Ratio measured			
iii	error calculated			
<b>2</b>	<b>Location of CVT</b>			
a	Date of Testing			
b	CVT ratio Test			
		Core I	Core II	Core III
i	Ratio Adopted			
ii	Ratio measured			
iii	error calculated			

**(2) Availability of Protection System****A. Bus Bar relay**

		765kV	400kV	220kV
i)	Make and Model of Bus Bar relay			
ii)	Whether stability checks done or not			
iii)	Date of testing			
iv)	Remarks (if any)			

**B. Sub-station protection and monitoring Equipment**

	System	LBB (Make & Model)	Functional (Yes / No)	Date of last testing	Event Logger (Make & Model)	Functional (Yes / No)	Synchronizing Facility Available or not	Synchro Check Relay (Make & Model)	Setting of Synchro check Relay
i)	765kV System								
ii)	400kV System								
iii)	220kV System								

**C. Transmission Line Protection**

1	Line-1 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
2	Line-2 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
3	Line-3 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
4	Line-4 (name of line)	Main-I Protection (Make and Model)	Functional (Yes / No)	Date of testing	Main-II Protection (Make and Model)	Functional (Yes / No)	Date of testing	LBB Protection (Make and Model)	Functional (Yes / No)	Date of testing
		PLCC/ Protection coupler (Make and Model)	Functional (Yes / No)	DR (Make & Model)	Functional (Yes / No)	Time Synch. Unit (Make & Model)	OK / Not OK			
5										

## D. Transformer Protection

1	ICT-1 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
2	ICT-3 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
3	ICT-3 (name of ICT)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
		Bucholtz / PRD	LA Rating HV Side	LA Rating LV Side	OTI/WTI Indication working or not	Date of last testing
		Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Current Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection
4						

## E. Reactor Protection

1	Reactor-1 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection	
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing		
2	Reactor-2 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection	
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing		
3	Reactor-3 (name of Line/Bus Reactor)	Differential Protection (Make & Model)	REF Protection (Make & Model)	Back-up Over Impedance Protection (Make & Model)	Over Flux Protection (Make & Model)	Other protection	
		Bucholtz / PRD	LA Rating HV Side	OTI/WTI Indication working or not	Date of last testing		



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## Annexure- IX

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### (3) Line Parameter

		Line-1	Line-2	Line-3	Line-4	Line-5
Name of Line						
Line length (km)						
Line Parameters ( In Ohms/Per KM/Per Phase Primary value)	R1					
	X1					
	R0					
	X0					
	R0M					
	X0M					
Relay setting	Adopte d	Please enclose the settings for all lines, transformers, Reactors and Bus Bars as Annexure-I				
	Recom mended	Please enclose the settings for all lines, transformers, Reactors and Bus Bars as Annexure-II				

### (4) DC Supply

		220 /110 V DC-I	220 /110 V DC-II	48 V DC- I	48 V DC- II
a)	Measured voltage (to be measured at farthest Panel)				
i.	Positive to Earth			NA	NA
ii.	Negative to Earth				
b)	No. of Cells Per Bank				
c)	Availability of Battery Charger	Yes/No	Yes/No	Yes/No	Yes/No



**(5) Circuit Breakers**

		Make and Model	Status of Breaker Available or Not	No.of trip/close coil & healthiness	PIR (Available or Not)	Date of Last Timing taken	Remarks (If any)
<b>A</b>	<b>765kV System</b>						
i	765kV bay-1						
ii	765kV bay-2						
iii	765kV bay-3						
iv	765kV bay-4						
v	765kV bay-5						
<b>B</b>	<b>400kV System</b>						
i	400kV bay-1						
ii	400kV bay-2						
iii	400kV bay-3						
iv	400kV bay-4						
v	400kV bay-5						
vi	400kV bay-6						
<b>C</b>	<b>220kV System</b>						
i	220kV bay-1						
ii	220kV bay-2						
iii	220kV bay-3						
iv	220kV bay-4						
v	220kV bay-5						

**(6) Availability of Auxiliary Supply**

**Auxiliary Supply-1:** Source of supply : .....  
Reliability of supply: .....  
Average trippings per month: .....

**Auxiliary Supply-2:** Source of supply : .....  
Reliability of supply: .....  
Average trippings per month: .....

.....

**DG Set-1:** Make .....  
Rating .....  
Weather on Auto or Manual .....  
Fuel Level .....

**DG Set-1:** Make .....  
Rating .....  
Weather on Auto or Manual .....  
Fuel Level .....

.....

.....

**(7) Availability of UFR Relay**

Make .....  
Setting .....

**(8) Availability of DF/DT Relay**

Make .....  
Setting .....

**(9) Special System Protection Scheme (SPS)**

Available (Yes/No) .....  
Verification .....

**(10) Status of corrective actions based on Tripping Analysis**

.....  
.....

**(11) Any other observation/ comments**

.....  
.....

\*\*\*\*\*

**Annexure-X****CHECK LIST TO ENABLE AUDIT OF PRACTICES FOLLOWED IN PROTECTION APPLICATION & CRITERIA USED FOR SETTING CALCULATIONS IN 220KV, 400KV & 765KV SUBSTATIONS****CHECK-LIST:**

Check list for different protected objects & elements in fault clearance system are as under:

(put  $\checkmark$  mark in the appropriate box )

**A. Transmission Lines (OHL and Cables)**

1.	Independent Main-I and Main-II protection (of different make OR different type) is provided with carrier aided scheme	<input type="checkbox"/> YES <input type="checkbox"/> NO
2.	Are the Main-I & Main-II relays connected to two separate DC sources (Group-A and Group-B)	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	Is the Distance protection (Non-switched type, suitable for 1-ph & 3-ph tripping) as Main1 and Main2 provided to ensure selectivity & reliability for all faults in the shortest possible time	<input type="checkbox"/> YES <input type="checkbox"/> NO
4.	Is both main-I & Main-II distance relay are numerical design having Quadrilateral or Polygon operating characteristic	<input type="checkbox"/> YES <input type="checkbox"/> NO
5.	In the Main-I / Main-II Distance protection, Zone-I is set cover 80% of the protected line section	<input type="checkbox"/> YES <input type="checkbox"/> NO
6.	In the Main-I / Main-II distance protection, Zone-2 is set cover 120% of the protected line section in case of Single circuit line and 150% in case of Double circuit line	<input type="checkbox"/> YES <input type="checkbox"/> NO
7.	In the Main-I / Main-II distance protection, Zone-3 is set cover 120% of the total of protected line section plus longest line at remote end as a minimum.	<input type="checkbox"/> YES <input type="checkbox"/> NO
8.	Resistive reach for Ground fault element set to give maximum coverage considering fault resistance, arc resistance & tower footing resistance. ( In case, It is not possible to set the ground fault and phase fault reaches separately, load point encroachment condition imposed on Phase fault resistive reach shall be applied)	<input type="checkbox"/> YES <input type="checkbox"/> NO
9.	Resistive reach for Phase fault element set to give maximum coverage subject to check of possibility against load point encroachment considering minimum expected voltage and maximum load.	<input type="checkbox"/> YES <input type="checkbox"/> NO

10.	In case of short lines, is manufacturers recommendation considered in respect of resistive setting vis a vis reactance setting to avoid overreach.	<input type="checkbox"/> YES <input type="checkbox"/> NO
11	Is Zone-2 time delay of Main-I / Main-II distance relay set to 0.350 seconds ? In case any other value has been set for Zone-II timer, kindly specify the value and justification thereof.	<input type="checkbox"/> YES <input type="checkbox"/> NO
12	Is Zone-3 timer is set to provide discrimination with the operating time of relays at adjacent sections with which Zone-3 reach of relay is set to overlap. Please specify the Zone-3 time set.	<input type="checkbox"/> YES <input type="checkbox"/> NO
13.	Is Zone-4 reach set in reverse direction to cover expected levels of apparent bus bar fault resistance, when allowing for multiple in feeds from other circuits?	<input type="checkbox"/> YES <input type="checkbox"/> NO
14.	Is reverse looking Zone-4 time delay set as Zone-2 time delay?	<input type="checkbox"/> YES <input type="checkbox"/> NO
15.	Is Switch on to fault (SOTF) function provided in distance relay to take care of line energisation on fault?  Whether SOTF initiation has been implemented using hardwire logic  In case of Breaker and half switching scheme, whether initiation of line SOTF from CB closing has been interlocked with the other CB	<input type="checkbox"/> YES <input type="checkbox"/> NO  <input type="checkbox"/> YES <input type="checkbox"/> NO  <input type="checkbox"/> YES <input type="checkbox"/> NO
16.	Whether VT fuse fail detection function has been correctly set to block the distance function operation on VT fuse failure	<input type="checkbox"/> YES <input type="checkbox"/> NO
17.	Is the sensitive IDMT directional E/F relay (either separate relay or built-in function of Main relay) for protection against high resistive earth faults?	<input type="checkbox"/> YES <input type="checkbox"/> NO
18.	Is additional element (Back-up distance) for remote back-up protection function provided in case of unit protection is used as Main relay for lines?	<input type="checkbox"/> YES <input type="checkbox"/> NO
19.	In case of Cables, is unit protection provided as Main-I & Main-II protection with distance as back-up.	<input type="checkbox"/> YES <input type="checkbox"/> NO
20.	Are the line parameters used for setting the relay verified by field testing	<input type="checkbox"/> YES <input type="checkbox"/> NO
21.	Is Two stages Over-Voltage protection provided for 765 & 400kV Lines?  Do you apply grading in over-voltage setting for lines at one station.  Please specify the setting values adopted for: Stage-I : (typical value - 106 to 112 % , delay : 4-7 Sec) Stage-II: (typical value - 140 to 150%, delay: 0 to 100msec.)	<input type="checkbox"/> YES <input type="checkbox"/> NO  <input type="checkbox"/> YES <input type="checkbox"/> NO  .....

22.	Is 1-ph Auto –reclosing provided on 765, 400 & 220kV lines? Please specify the set value: Dead time: (typical 1 Sec) Reclaim time: (typical 25 Sec)	<input type="checkbox"/> YES <input type="checkbox"/> NO  ..... .....
23.	Is the Distance communication. Scheme Permissive Over Reach (POR) applied for short lines and Permissive Under Reach (PUR) applied for long lines? If any other communication scheme has been applied, please provide the detail with justification thereof.	<input type="checkbox"/> YES <input type="checkbox"/> NO  .....
24.	Is the Current reversal guard logic for POR scheme provided on Double circuit lines?	<input type="checkbox"/> YES <input type="checkbox"/> NO
25.	In case the protected line is getting terminated at a station having very low fault level i.e. HVDC terminal, whether week end-infeed feature has been enabled in respective distance relay or not	<input type="checkbox"/> YES <input type="checkbox"/> NO
26.	In case of protected line is originating from nuclear power station, are the special requirement (stability of nuclear plant auxiliaries) as required by them has been met	<input type="checkbox"/> YES <input type="checkbox"/> NO
27.	What line current , Voltage and Load angle have been considered for Load encroachment blinder setting and what is the resultant MVA that the line can carry without load encroachment. (In the absence of Load encroachment blinder function, this limit shall be applied to Zone-3 phase fault resistive reach.)	I= V= Angle: S=
28.	a) What are the Zones blocked on Power swing block function: b) Setting for Unblock timer: (typical 02 second) c) Out of Step trip enabled	Z1 / Z2 / Z3 / Z4 Time: <input type="checkbox"/> YES <input type="checkbox"/> NO
29.	Whether the location of Out of step relay has been identified on the basis of power system simulation studies	<input type="checkbox"/> YES <input type="checkbox"/> NO
30.	a) Is Disturbance recorder and Fault locator provided on all line feeder ? b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC d) Whether DR is time synchronised with the GPS based time synchronising equipment e) Whether DR analog channels contain line phase & neutral current and line phase & neutral	<input type="checkbox"/> YES <input type="checkbox"/> NO Standalone / built-in  <input type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> YES <input type="checkbox"/> NO



	voltage.  f) Whether DR digital channel as a minimum contain the CB status, Main-I & II trip status, LBB trip status, Over-voltage trip status, Stub protn trip status, Permissive and direct carrier receive status, Line reactor trip status.	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>31.</b>	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	<input type="checkbox"/> YES <input type="checkbox"/> NO

### B. Power Transformers

<b>1.</b>	Do you use Group A and Group B protections connected to separate DC sources for power transformers	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>2.</b>	Do you follow CBIP guideline (274 & 296) for protection setting of transformer	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>3.</b>	Do you use duplicated PRD and Bucholtz initiating contact for power transformers at 765kV and 400kV levels	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>4.</b>	Do you classify transformer protections as below in groups: Group A Group B <ul style="list-style-type: none"> <li>• Biased differential relay Restricted earth fault (REF) relay</li> <li>• PRD , WTI Buchholz Protection OTI</li> <li>• Back up Protection(HV) Back up Protection(MV)</li> <li>• Over fluxing protection(HV) Over fluxing protection(MV)</li> </ul>	<input type="checkbox"/> YES <input type="checkbox"/> NO  Group A or B
<b>5.</b>	In case of Breaker & half switching scheme, whether CT associated with Main & Tie Breakers are connected to separate bias winding of the low impedance Biased differential protection in order to avoid false operation due to dissimilar CT response.	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>6.</b>	Is Restricted earth fault (REF) protection used a high impedance type	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>7.</b>	Are Main protection relays provided for transformers are of numerical design.	<input type="checkbox"/> YES <input type="checkbox"/> NO
<b>8.</b>	a) Are directional over current & earth fault relays provided as back-up protection of Transformer are of numerical design.	<input type="checkbox"/> YES <input type="checkbox"/> NO  <input type="checkbox"/> YES <input type="checkbox"/> NO

	b) Do the back-up earth fault relays have harmonic restrain feature	
9.	Is Fire protection system (HVW type) )/N <sub>2</sub> fire extinguisher system provided for power transformer and functioning	<input type="checkbox"/> YES <input type="checkbox"/> NO
10.	a) Is the Disturbance recorder provided for Transformer feeder b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC d) Whether DR is time synchronised with the GPS time synchronising equipment	<input type="checkbox"/> YES <input type="checkbox"/> NO Standalone/built-in <input type="checkbox"/> YES <input type="checkbox"/> NO <input type="checkbox"/> YES <input type="checkbox"/> NO
11.	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	<input type="checkbox"/> YES <input type="checkbox"/> NO

### C. Shunt Reactors

1.	Do you use Group A and Group B protections connected to separate DC sources for reactors	<input type="checkbox"/> YES <input type="checkbox"/> NO										
2.	Do you follow CBIP guideline (274 and 296) for protection setting of reactors	<input type="checkbox"/> YES <input type="checkbox"/> NO										
3.	Do you use duplicated PRD and Bucholtz initiating contact for Reactors at 765kV and 400kV levels	<input type="checkbox"/> YES <input type="checkbox"/> NO										
4.	Do you classify Reactor protections as below in groups: <table style="width: 100%; border: none;"> <tr> <td style="width: 50%; text-align: center;">Group A</td> <td style="width: 50%; text-align: center;">Group B</td> </tr> <tr> <td>• Biased differential relay</td> <td></td> </tr> <tr> <td>• (High impedance type]</td> <td style="text-align: center;">R.E.F Protection</td> </tr> <tr> <td>• PRD , WTI</td> <td style="text-align: center;">Buchholz Protection, OTI</td> </tr> <tr> <td>• Back up impedance protection</td> <td style="text-align: center;">O/C &amp; E/F relay</td> </tr> </table>	Group A	Group B	• Biased differential relay		• (High impedance type]	R.E.F Protection	• PRD , WTI	Buchholz Protection, OTI	• Back up impedance protection	O/C & E/F relay	<input type="checkbox"/> YES <input type="checkbox"/> NO Group A or B
Group A	Group B											
• Biased differential relay												
• (High impedance type]	R.E.F Protection											
• PRD , WTI	Buchholz Protection, OTI											
• Back up impedance protection	O/C & E/F relay											
5	In case of Breaker & half switching scheme, whether CT associated with Main & Tie Breakers are connected to separate bias winding of the low impedance Biased differential protection in order to avoid false operation due to dissimilar CT response.	<input type="checkbox"/> YES <input type="checkbox"/> NO										
6	Is Restricted earth fault (REF) protection used a high impedance type	<input type="checkbox"/> YES <input type="checkbox"/> NO										

7	Are Main & back-up protection relays provided for Reactor are of numerical design.	<input type="checkbox"/> YES <input type="checkbox"/> NO
8	Is Fire protection system (HVW type)/N <sub>2</sub> fire extinguisher system provided for Reactor and functioning	<input type="checkbox"/> YES <input type="checkbox"/> NO
9	a) Is the Disturbance recorder and Fault locator provided on all the Shunt Reactors used in 765 kV, 400 kV substations? b) Whether standalone or built in Main relay c) Whether DR is having automatic fault record download facility to a central PC	<input type="checkbox"/> YES <input type="checkbox"/> NO Standalone/built-in <input type="checkbox"/> YES <input type="checkbox"/> NO
10.	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	<input type="checkbox"/> YES <input type="checkbox"/> NO

**D. Bus bars**

1.	Bus Bar protection for 765, 400 & 220kV buses is provided	<input type="checkbox"/> YES <input type="checkbox"/> NO
2.	Duplicated Bus bar protection is provided for 765kV and 400kV buses	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	CBIP guideline for Protection (274 and 296) settings is followed	<input type="checkbox"/> YES <input type="checkbox"/> NO
4	In an existing substation if CTs are of different ratios, is biased type bus protection provided.	<input type="checkbox"/> YES <input type="checkbox"/> NO
5	In stations where single bus bar protection is provided, is backup provided by reverse looking elements of distance relays or by second zone elements of remote end distance relays?	<input type="checkbox"/> YES <input type="checkbox"/> NO
6	In case of GIS where burn through time of SF <sub>6</sub> is shorter than remote back up protection is the bus bar protection duplicated irrespective of voltage level?	<input type="checkbox"/> YES <input type="checkbox"/> NO
7	Since it is difficult to get shutdowns to allow periodic testing of bus protection, numerical bus protections with self-supervision feature is an answer. Is this followed?	<input type="checkbox"/> YES <input type="checkbox"/> NO
8	Does the Setting document for the numerical relays (IED) contain all the settings for all functions that are used and indicates clearly the functions not used (to be Blocked / Disabled). Are all default settings validated or revised settings given in the setting document?	<input type="checkbox"/> YES <input type="checkbox"/> NO

**E. Disturbance Recorder (DR) and Event Logger (EL)**

1	<p>a) Is the Disturbance recorder and Fault locator provided on all line feeders of 765, 400 &amp; 220kV substations?</p> <p>b) Whether standalone or built in Main relay</p> <p>c) Whether DR is having automatic fault record download facility to a central PC</p> <p>d) Whether Central PC for DR , EL are powered by Inverter (fed from station DC)</p>	<p><input type="checkbox"/> YES    <input type="checkbox"/> NO</p> <p>Standalone / built-in</p> <p><input type="checkbox"/> YES    <input type="checkbox"/> NO</p> <p><input type="checkbox"/> YES    <input type="checkbox"/> NO</p>
2.	<p>Whether DR is having the following main signals for lines:</p> <p><u>Analogue signals:</u></p> <ul style="list-style-type: none"> <li>• From CT: IA, IB, IC, IN</li> <li>• From VT: VAN, VBN, VCN</li> <li>• From Aux. VT: V0</li> </ul> <p><u>Digital Signals</u></p> <ul style="list-style-type: none"> <li>• Main I Carrier receive</li> <li>• Main I Trip</li> <li>• Line O/V Stage I / Stage II</li> <li>• Reactor Fault Trip</li> <li>• Stub Protection Operated.</li> <li>• Main II Trip</li> <li>• Main II Carrier Receive</li> <li>• Direct Trip CH I / II</li> <li>• CB I Status (PH-R, Y &amp; B)</li> <li>• CB II Status (PH R, Y &amp; B)</li> <li>• Bus bar trip</li> <li>• Main / Tie CB LBB Operated</li> <li>• Main / Tie Auto-reclose operated.</li> </ul> <p>DR for Transformer / Reactor feeder should contain analog channel like input currents &amp; voltage. Binary signal include all protection trip input, Main &amp; Tie CB status, LBB trip</p>	<p><input type="checkbox"/> YES    <input type="checkbox"/> NO</p>
3.	<p>Whether substation (765, 400 , 220kV) is having Event logger facility (standalone or built-in-SAS)</p>	<p><input type="checkbox"/> YES    <input type="checkbox"/> NO</p>

4.	Whether GPS based time synchronizing equipment is provided at the substation for time synchronizing of Main relays / DR/ Event logger / SAS/ PMU / Line Current Differential Relays	<input type="checkbox"/> YES <input type="checkbox"/> NO
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### F. Circuit Breakers

1.	Is breaker fail protection ( LBB / BFR) provided for all the Circuit Breakers at 220kV , 400kV & 765kV rating	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	For Circuit Breaker connected to line feeder / transformer feeder, whether operation of LBB / BFR sends direct trip signal to trip remote end breaker ?	<input type="checkbox"/> YES <input type="checkbox"/> NO
4.	For lines employing single phase auto reclosing, Is start signal from protection trip to LBB / BFR relay is given on single phase basis?	<input type="checkbox"/> YES <input type="checkbox"/> NO
5.	Is separate relay provided for each breaker and the relay has to be connected from the secondary circuit of the CTs associated with that particular breaker?	<input type="checkbox"/> YES <input type="checkbox"/> NO
6.	Is LBB relay provided with separate DC circuit independent from Group-A and Group-B Protections?	<input type="checkbox"/> YES <input type="checkbox"/> NO
7.	Is the LBB initiation provided with initiating contact independent of CB trip relay contact?	<input type="checkbox"/> YES <input type="checkbox"/> NO
8.	Is Separation maintained between protective relay and CB trip coil DC circuit so that short circuit or blown fuse in the CB circuit will not prevent the protective relay from energizing the LBB scheme?	<input type="checkbox"/> YES <input type="checkbox"/> NO
9.	Is LBB relay initiated by Bus bar protection in addition to other fault sensing relays, since failure of CB to clear a bus fault would result in the loss of entire station if BFP relay is not initiated?	<input type="checkbox"/> YES <input type="checkbox"/> NO
10.	Is tripping logic of the bus bar protection scheme used for LBB protection also?	<input type="checkbox"/> YES <input type="checkbox"/> NO
11.	Are the special considerations provided to ensure proper scheme operation by using Circuit Breaker contact logic in addition to current detectors in cases breaker-fail relaying for low energy faults like buckholz operation?	<input type="checkbox"/> YES <input type="checkbox"/> NO
12.	Are the Current level detectors set as sensitive as the main protection? (Generally setting of 0.2 A is commonly practiced for lines and transformers)	<input type="checkbox"/> YES <input type="checkbox"/> NO
13.	Is timer set considering breaker interrupting time, current detector reset time and a margin? (Generally a timer setting of 200ms has been found to be adequate)	<input type="checkbox"/> YES <input type="checkbox"/> NO
14.	Is the back-up fault clearance time is shorter than the operating time of the remote protections (distance relay Zone-2) ?	<input type="checkbox"/> YES <input type="checkbox"/> NO

15.	Is the breaker failure protection provided with two steps (First stage – retrip own CB, Second stage- Trip all associated CBs). This mitigates unwanted operation of breaker failure protection during maintenance and fault tracing.	<input type="checkbox"/> YES <input type="checkbox"/> NO
16.	Is the breaker failure protection hardware provided is separate from line /transformer feeder protection?	<input type="checkbox"/> YES <input type="checkbox"/> NO

### G. Communication systems

1.	<p>a) Do you use PLCC for tele-protection of distance relays at 765, 400 &amp; 220kV feeders</p> <p>b) Specify type of coupling</p> <p>c) Whether redundant PLCC channels provided for 400 &amp; 765kV lines</p> <p>d) Specify number of PLCC channels per circuit :</p> <p>e) Whether dependability &amp; security of each tele-protection channel measured &amp; record kept?</p>	<input type="checkbox"/> YES <input type="checkbox"/> NO (Ph-Ph / Ph-G/ Inter-ckt) <input type="checkbox"/> YES <input type="checkbox"/> NO ( One / two) <input type="checkbox"/> YES <input type="checkbox"/> NO
2.	<p>a) In case you use OPGW for tele-protection, are they on geographically diversified route for Main-I and Main-II relay?</p> <p>b) Whether dedicated fiber is being used for Main-I / Main-II relay or multiplexed channel are being used.</p>	<input type="checkbox"/> YES <input type="checkbox"/> NO  Dedicated / multiplexed

### H. Station DC supply systems

1.	Do you have two separate independent DC system (220V or 110V) (Source-A and Source-B)	<input type="checkbox"/> YES <input type="checkbox"/> NO
2.	Do you have two independent DC system (48V) for PLCC (source-A and source-B)	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	There is no mixing of supplies from DC source-A and DC source-B	<input type="checkbox"/> YES <input type="checkbox"/> NO
4.	Whether the protection relays and trip circuits are segregated into two independent system fed through fuses from two different DC source	<input type="checkbox"/> YES <input type="checkbox"/> NO
5.	Whether Bay wise distribution of DC supply done in the following way: <p>a) Protection</p> <p>b) CB functions</p> <p>c) Isolator / earth switch functions</p> <p>d) Annunciation / Indications</p> <p>e) Monitoring functions</p>	<input type="checkbox"/> YES <input type="checkbox"/> NO

6	Whether following has been ensured in the cabling: a) Separate cables are used for AC & DC circuits b) Separate cables are used for DC-I & DC-II circuits c) Separate cables are used for different cores of CT and CVT outputs to enhance reliability & security	<input type="checkbox"/> YES <input type="checkbox"/> NO
7	Is guidelines prescribed in CBIP manual 274 & 296 followed in general	<input type="checkbox"/> YES <input type="checkbox"/> NO

### I. PERFORMANCE INDICES

1.	Is there a system of periodically measuring Dependability & Security of Protection system (as given in CBIP manual 296) and recorded	<input type="checkbox"/> YES <input type="checkbox"/> NO
2.	Is there a system of periodically measuring Dependability of switchgear associated with Protection system and recorded	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	Is there a process of Root cause analysis of unwanted tripping events	<input type="checkbox"/> YES <input type="checkbox"/> NO
4.	Are improvement action like revision of relay setting, better maintenance practices, modernising & retrofitting of switching & protection system taken based on above data?	<input type="checkbox"/> YES <input type="checkbox"/> NO
5.	Is attention also given to DC supply system, tele-protection signaling, healthiness of tripping cables, terminations etc. in order to improve the performance of fault clearance system	<input type="checkbox"/> YES <input type="checkbox"/> NO

### J. ADDITIONAL CHECKS FOR SERIES COMPENSATED LINES

1.	What is the operating principle of Main protection employed	<input type="checkbox"/> Distance <input type="checkbox"/> Line Current differential
2.	Are both main-I & Main-II distance relay are numerical design	<input type="checkbox"/> YES <input type="checkbox"/> NO
3.	Are both main-I & Main-II distance relay suitable for Series compensated lines	<input type="checkbox"/> YES <input type="checkbox"/> NO
4.	Are POR tele-protection scheme employed for distance relays	<input type="checkbox"/> YES <input type="checkbox"/> NO
5.	Position of Line VT provided on series compensated line	<input type="checkbox"/> Between Capacitor and line <input type="checkbox"/> Between Capacitor and Bus
6.	What is the under reaching (Zone 1) setting used in teleprotection schemes (Local & Remote end)	% of line length Rationale:
7.	What is the overreaching (Zone 2) setting in used teleprotection schemes	% of line length Rationale:
8.	What kinds of measurement techniques are used to cope with voltage inversion?	<input type="checkbox"/> Phase locked voltage memory

		<input type="checkbox"/> Intentional time delay Other, specify:	*****
9.	Whether system studies carried out to check the possibility of current inversion due to series compensation	<input type="checkbox"/> YES <input type="checkbox"/> NO	
10.	Whether any system studies conducted to find the impact of series compensation on the performance of protections installed on adjacent lines? If yes, how many lines were found to be affected ?. Pl. specify _____	<input type="checkbox"/> YES <input type="checkbox"/> NO	
11	If YES, are the affected protections on adjacent lines changed / setting revised after the introduction of series compensation?	<input type="checkbox"/> YES <input type="checkbox"/> NO	
12.	Is dynamic simulation done to fine tune settings of distance relay installed on series compensated double circuit lines?	<input type="checkbox"/> YES <input type="checkbox"/> NO	
13.	Whether performance of directional earth fault relay verifies by simulation studies	<input type="checkbox"/> YES <input type="checkbox"/> NO	
14.	When is flashover of spark gaps expected?	<input type="checkbox"/> For protected line Faults up to ohms  <input type="checkbox"/> For external faults an adjacent lines	
15.	Whether measures taken for under/overreach problems at sub-harmonic oscillations?	<input type="checkbox"/> YES <input type="checkbox"/> NO	
16.	Whether MOV influence considered while setting the distance relay reach	<input type="checkbox"/> YES <input type="checkbox"/> NO	
17.	Have you experienced any security problems (Relay mal-operation) with high frequency transients caused by <input type="checkbox"/> Flashover of spark gaps <input type="checkbox"/> Line energisation Other, specify:	<input type="checkbox"/> YES <input type="checkbox"/> NO	
18.	If YES, how the above problem has been addressed?	_____ _____	

By order of the Commission

**Secretary**  
**KARNATAKA ELECTRICITY REGULATORY COMMISSION**