

# Indian Electricity Grid Code

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## Central Electricity Regulatory Commission

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## **CHAPTER –1**

### **GENERAL**

#### **1.1 Introduction**

The Indian Power System is a conglomeration of a number of agencies. The Indian Electricity Grid Code (IEGC) lays down the rules, guidelines and standards to be followed by the various agencies and participants in the system to plan, develop, maintain and operate the power system, in the most efficient, reliable, economic and secure manner, while facilitating healthy competition in the generation and supply of electricity.

#### **1.2 Objective**

The IEGC brings together a single set of technical rules, encompassing all the Utilities connected to/or using the inter-State transmission system (ISTS) and provides the following:

- Documentation of the principles and procedures which define the relationship between the various Users of the inter-State transmission system (ISTS), as well as the Regional and State Load Despatch Centres
- Facilitation of the operation, maintenance, development and planning of economic and reliable Regional Grid
- Facilitation for beneficial trading of electricity by defining a common basis of operation of the ISTS, applicable to all the Users of the ISTS

#### **1.3 Scope**

- i) All parties that connect with and/or utilize the ISTS are required to abide by the principles and procedures defined in the IEGC in so far as they apply to that party.
- ii) For the purpose of the IEGC, the Damodar Valley Corporation (DVC) will be treated similar to an STU/SEB, in view of the fact that DVC is a vertically integrated utility like an SEB and has its own generation, transmission and distribution in the identified command area.
- iii) For the purpose of the IEGC, the generating stations of the Bhakra Beas Management Board (BBMB) and Sardar Sarover Narmada Nigam Ltd. (SSNNL) shall be treated as intra-State

generating stations, but their transmission systems shall be a part of the ISTS. This is because of the fact that only some of the States of Northern Region/Western Region have a share in BBMB/SSNNL, and their generating units have to be scheduled and dispatched in a very special manner (in coordination with the irrigational requirements). The scheduling and despatch of the BBMB/SSNNL generation shall continue to be the responsibility of the BBMB/SSNNL, with a proviso that it shall be duly coordinated with respective Regional Load Despatch Centre and the beneficiaries.

- iv) This IEGC shall come into effect from 01.04.2006.

#### **1.4 Structure of the IEGC**

This IEGC contains the following:

- i) **Role of various Organizations and their linkages**

This chapter defines the functions of the various Organizations as are relevant to IEGC.

- ii) **Planning Code for inter-State transmission**

This Chapter provides the policy to be adopted in the planning and development of bulk power transfer and associated ISTS. The Planning Code lays out the detailed information exchange required between the planning agencies and the various participants of the power system for load forecasting, generation availability, and power system planning etc. for the future years under study. The Planning Code stipulates the various criteria to be adopted during the planning process.

- iii) **Connection Conditions**

This chapter specifies minimum technical and design criteria to be complied with by any agency connected to the system or seeking connection to the ISTS, to maintain uniformity and quality across the system. This includes:

- a) Procedure for connection to the ISTS
- b) Site responsibility schedule

iv) **Operating Code for Regional Grids**

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

(a) **Operating Policy**

(b) **System security aspects**

This section describes the general security aspects to be followed by generating companies and all Regional Constituents of the Grid.

(c) **Demand Estimation for operational purposes**

This section details the procedures to estimate the demand by the various constituents for their systems for the day/week/month/year ahead, which shall be used for operational planning.

(d) **Demand management**

This section identifies the methodology to be adopted for demand control by each regional constituent as a function of the frequency and deficit generation.

(e) **Periodic Reports**

This section provides various provisions for reporting of the operating parameters of the grid such as frequency profile etc.

(f) **Operational liaison**

This section sets out the requirement for the exchange of information in relation to normal operation and/or events in the grid.

(g) **Outage Planning**

This section indicates procedure for outage planning.

(h) **Recovery procedures**

This section contains the procedures to be adopted following a major grid disturbance, for black start and resynchronization of islands, etc.

(i) **Event Information**

This section indicates the procedure by which events are reported and the information exchange etc. takes place.

v) **Scheduling & Despatch Code**

This section deals with the procedure to be adopted for scheduling and despatch of generation of the Inter-State Generating Stations (ISGS) including complementary commercial mechanisms, on a daily basis with the modality of the flow of

information between the ISGS, Regional Load Despatch Centre (RLDC) and the State Load Despatch Centres (SLDCs).

vi) **Inter-Regional Exchanges**

This Chapter deals with special considerations for operation of inter-regional links.

vii) **Management of IEGC**

This Chapter deals with the procedure for review/amendment and management of IEGC.

## **1.5 Non-compliance**

In case of a persistent non-compliance of any of the stipulations of the IEGC by a constituent or an agency (other than RPC and RLDC), the matter shall be reported by any agency/RLDC to the Member Secretary, RPC. The Member Secretary, RPC, shall verify and take up the matter with the defaulting agency for expeditious termination of the non-compliance. In case of inadequate response to the efforts made by the Member Secretary, RPC, the non-compliance shall be reported to CERC. CERC, in turn after due process, may order the defaulting agency for compliance, failing which; the CERC may take appropriate action.

RPC shall maintain appropriate records of such violations.

In case of a non-compliance of any of the stipulations of the IEGC by RLDC or RPC, the matter shall be reported to the CERC.

## **1.6 Free Governor Action**

- i) All thermal and hydro (except those with zero pondage) generating units : with effect from the date to be separately notified by the Commission.
- ii) Any exemption from the above may be granted only by CERC for which the concerned constituent/ agency shall file a petition in advance.
- iii) The Gas turbine/Combined Cycle Power Plants and Nuclear Power Stations shall be exempted from Sections 4.8 (c), 4.8 (d), 5.2 (e), 5.2 (f), 5.2 (g) and 5.2 (h) till the Commission reviews the situation.

## 1.7 Charge/Payment for Reactive Energy Exchanges

The rate for charge/payment of reactive energy exchanges (according to the scheme specified in section 6.6 shall be 5.0 paise/kVArh w.e.f 01.04.2006, and shall be escalated at 0.25 paise/kVArh per year thereafter, unless otherwise revised by the CERC.

## 1.8 Exemptions

Any exemption from provisions of IEGC shall become effective only after approval of the Commission, for which the agencies will have to file a petition in advance.

## 1.9 Glossary and Definitions

ITEM	DEFINITION
<b>Act</b>	The Electricity Act, 2003
Agency	A term used in the various sections of the IEGC to refer to ISGS/Licensee that utilize the ISTS.
Authority	Central Electricity Authority referred to in sub-section (1) of Section 70 of the Act.
Automatic Voltage Regulator (AVR)	A continuously acting automatic excitation control system to control the voltage of a Generating Unit measured at the generator terminals.
BBMB	The Bhakra Beas Management Board
Beneficiary	A person who has a share in an ISGS.
Black Start Procedure	The procedure necessary to recover from a partial or a total blackout.



Bulk Power Transmission Agreement (BPTA)	The commercial agreement between the transmission licensee and a long term customer for the provision of transmission services.
BIS	The Bureau of Indian Standards.
Captive Generating Plant (CGP)	Captive Generating 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.
Capacitor	An electrical facility provided for generation of reactive power.
CEA	The Central Electricity Authority
CERC	The Central Electricity Regulatory Commission referred to in sub-section (1) of Section 76..
Central Transmission Utility (CTU)	Central Transmission Utility means any Government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act.
Connection Agreement	An Agreement between CTU and an agency setting out the terms relating to a connection to and/or use of the Inter State Transmission System.
Connection Point	A point at which a agency's Plant and/or Apparatus connects to the Inter State Transmission System.
Constituent	A State of the Region (represented by its SEB/STU), a Union Territory (represented by its Electricity Department), a Generating Company having a ISGS in the Region, Central Transmission Utility and DVC/BBMB/SSNNL (in the respective Region).
Demand	The demand of Active Power in MW and Reactive Power in MVAR of electricity unless otherwise stated.

Despatch Schedule	The ex-power plant net MW and MWH output of a generating station, scheduled to be exported to the Grid from time to time.
Disturbance Recorder (DR)	A device provided to record the behaviour of the pre-selected digital and analog values of the system parameters during an Event.
Data Acquisition System (DAS)	A device provided to record the sequence of operation in time, of the relays/equipments/system parameters at a location.
Drawal Schedule	The, ex-power plant, MW that a State is scheduled to receive from the ISGS, including bilateral exchanges from time to time.
DVC	The Damodar Valley Corporation established under sub-section (1) of Section 3 of the Damodar Valley Corporation Act, 1948.
Entitlement	Share of a beneficiary (in MW and MWH) in the installed capacity/output capability of an ISGS.
Event	An unscheduled or unplanned occurrence on a Grid including faults, incidents and breakdowns.
Event Logger (EL)	A device provided to record the sequence of operation in time, of the relays/equipments at a location during an Event.
Ex-Power Plant	Net MW/MWH output of a generating station, after deducting auxiliary consumption and transformation losses.
Fault Locator (FL)	A device provided at the end of a transmission line to measure/indicate the distance at which a line fault may have occurred.
Flexible Alternating Current Transmission (FACT)	Facilities that enable power flows on A.C lines to be regulated, to control loop flows, line loadings, etc.

Force Majeure	<p>Any event which is beyond the control of the agencies 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 affect the performance by either agency such as but not limited to :-</p> <p>a)Acts of God, natural phenomena, including but not limited to floods, droughts, earthquakes and epidemics;</p> <p>b)Acts of any Government domestic or foreign, including but not limited to war declared or undeclared, hostilities, priorities, quarantines, embargoes;</p> <p>c)Riot or Civil Commotion</p> <p>d)Grid's failure not attributable to agencies involved..</p>
Forced Outage	<p>An outage of a Generating Unit or a transmission facility due to a fault or other reasons which has not been planned.</p>
Generating Company	<p>Generating Company means any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person, which owns or operates or maintains a generating station.</p>
Generating Unit	<p>An electrical Generating Unit coupled to a turbine within a Power Station together with all Plant and Apparatus at that Power Station (up to the Connection Point) which relates exclusively to the operation of that turbo-generator.</p>

Good Utility Practices	Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period which could have been expected to accomplish the desired results at a reasonable cost consistent with good business practices, reliably, safely and with expedition.
Governor Droop	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 free governor action to change its output from zero to full load.
Grid Standards	Grid Standards specified by the Authority under clause (d) of the Section 73 of the Act.
Extra High Voltage (EHV)	Where the voltage exceeds 33,000 volts under normal conditions, subject, however, to the percentage variation allowed by the Authority.
Independent Power Producer (IPP)	A generating company not owned/controlled by the Central/State Government.
Indian Electricity Grid Code (IEGC)	A document describing the philosophy and the responsibilities for planning and operation of Indian power system specified by the Commission in accordance with sub section 1(h) of Section 79 of the Act..
Inter-State Generating Station (ISGS)	A Central/other generating station in which two or more states have shares and whose scheduling is to be coordinated by the RLDC.

Inter State Transmission System (ISTS)	Inter-State Transmission System includes  i) any system for the conveyance of electricity by means of a main transmission line from the territory of one State to another State  ii) The conveyance of energy across the territory of an intervening State as well as conveyance within the State which is incidental to such inter-state transmission of energy  (iii) The transmission of electricity within the territory of State on a system built, owned, operated, maintained or controlled by CTU.
IEC	The International Electro technical Commission.
Licensee	Licence means a person who has been granted a licence under Section 14 of the Act.
Load	The MW/MWH consumed by a utility/ installation.
Long-term customer	A person availing or intending to avail access to the ISTS for a period of 25 years or more and who has signed BPTA with the transmission licensee.
Maximum Continuous Rating (MCR)	The normal rated full load MW output capacity of a Generating Unit which can be sustained on a continuous basis at specified conditions.
National Grid	The entire inter-connected electric power network of the country, which would evolve after inter-connection of Regional grids.
Net Drawal Schedule	The drawal schedule of a beneficiary after deducting the apportioned transmission losses (estimated).
Operation	A scheduled or planned action relating to the operation of a System.

Operation Co-ordination Committee (OCC)	A committee of RPC with members from all the Constituents which decides the operational aspects of the Regional Grid.
Operating range	The operating range of frequency and voltage as specified under the operating code (Chapter-6)
Pool Account	Regional account for (i) payments regarding unscheduled - interchanges (UI Account) or (ii) reactive energy exchanges (Reactive Energy Account), as the case may be
POWERGRID	Power Grid Corporation of India Limited which has been notified as CTU.
Power System	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.
Reactor	An electrical facility specifically designed to absorb Reactive Power.
Regional .Power Committee (RPC)	“Regional Power Committee” 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.
RPC Secretariat	The Secretariat of the RPC.

Regional Energy Account (REA)	A regional energy account, for the billing and settlement of 'Capacity Charge', 'Energy Charge', 'UI Charge' and 'Reactive Charge'.
Regional Grid	The entire synchronously connected electric power network of the concerned Region, comprising of ISTS, ISGS and intra-state systems.
Regional Load Despatch Centre (RLDC)	'Regional Load Despatch Centre' means the Centre established under sub-section (1) of Section 27 of the Act.
Share	Percentage share of a beneficiary in an ISGS notified by Government of India or as agreed to in the agreement between ISGS and its beneficiaries.
Single Line Diagram (SLD)	Diagrams which are a schematic representation of the HV/EHV apparatus and the connections to all external circuits at a Connection Point incorporating its numbering nomenclature and labelling.
Site Common Drawing	Drawings prepared for each Connection Point, which incorporates layout drawings, electrical layout drawings, common protection/control drawings and common service drawings.
Spinning Reserve	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 dispatch instruction or instantaneously in response to a frequency drop.
Standing Committee for Transmission Planning	A Committee constituted by the CEA to discuss, review and finalise the proposals for expansion or modification in the ISTS and associated intra-state systems.
SEB	The State Electricity Board including the State Electricity Department.
SERC	State Electricity Regulatory Commission

SSNNL	Sardar Sarover Narmada Nigam Ltd.
State Load Despatch Centre (SLDC)	'State Load Despatch Centre' means the Centre established under sub-section (1) of Section 31 of the Act.
State Transmission Utility (STU)	'State Transmission Utility' means the Board or the Government Company specified as such by the State Government under sub-section (1) of Section 39 of the Act.
Static VAR Compensator (SVC)	An electrical facility designed for the purpose of generating or absorbing Reactive Power.
Technical Co-ordination Committee (TCC)	The committee set up by RPC to coordinate the technical and commercial aspects of the operation of the regional grid.
Time Block	Block of 15 minutes each for which special energy Meters record specified electrical parameters and quantities with first time block starting and 00.00 Hrs.
Transmission License	A Licence granted under Section 14 of the Act to transmit electricity.
Transmission Planning Criteria	The policy, standards and guidelines issued by the CEA for the planning and design of the Transmission system.
User	A term utilized in the various sections of the IEGC to refer to the persons/agencies using the ISTS, as more particularly identified in each section of the IEGC.



## CHAPTER-2

### **ROLE OF VARIOUS ORGANIZATIONS AND THEIR LINKAGES**

#### **2.1 Introduction**

2.1.1 In the light of the Electricity Act, 2003, it has become necessary to re-define the role of Regional Load Despatch Centres (RLDCs), Regional Power Committees (RPCs)/Regional Electricity Boards (REBs), the Central Transmission Utility (CTU) etc. and their organizational linkage so as to facilitate development and smooth operation of Regional Grids and National Grid at large. This Chapter defines the function of the various organizations so far as it relates to the Grid Code.

#### **2.2. Role of RLDCs**

2.2.1 According to sections 28 and 29 of Electricity Act, 2003, the functions of RLDCs are as follows:

- (1) The Regional Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in the concerned region.
- (2) The Regional Load Despatch Centre shall comply with such principles, guidelines and methodologies in respect of wheeling and optimum scheduling and despatch of electricity as may be specified in the Grid Code.
- (3) The Regional Load Despatch Centre shall-
  - (a) be responsible for optimum scheduling and despatch of electricity within the region, in accordance with the contracts entered into with the licensees or the generating companies operating in the region;
  - (b) monitor grid operations;
  - (c) keep accounts of quantity of electricity transmitted through the regional grid;
  - (d) exercise supervision and control over the Inter-State transmission system ; and
  - (e) be responsible for carrying out real time operations for grid control and despatch of electricity within the region through secure and economic operation of the regional grid in accordance with the Grid Standards and the Grid Code.
- (4) The Regional Load Despatch Centre may give such directions and exercise such supervision and control as may be required for ensuring stability of grid operations and for achieving the maximum economy and efficiency in the operation of the power system in the region under its control.
- (5) 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 Regional Load Despatch Centres.

- (6) All directions issued by the Regional Load Despatch Centres to any transmission licensee of State transmission lines or any other licensee of the State or generating company (other than those connected to inter-State transmission system) or sub-station in the State shall be issued through the State Load Despatch Centre and the State Load Despatch Centres shall ensure that such directions are duly complied with by the licensee or generating company or sub-station.
- (7) If any dispute arises with reference to the quality of electricity or safe, secure and integrated operation of the regional grid or in relation to any direction given by the Regional Load Despatch Centre, it shall be referred to Central Commission for decision. However, pending the decision of the Central Commission, the directions of the Regional Load Despatch Centre shall be complied with by the State Load Despatch Centre or the licensee or the generating company, as the case may be.

2.2.2 The following are contemplated as exclusive functions of RLDCs

- (1) System operation and control including inter-state / inter-regional transfer of power, covering contingency analysis and operational planning on real time basis;
- (2) Scheduling / re-scheduling of generation;
- (3) System restoration following grid disturbances;
- (4) Metering and data collection;
- (5) Compiling and furnishing data pertaining to system operation;
- (6) Operation of regional UI pool account and regional reactive energy account.

2.2.3 In case of Open access in Inter-state Transmission, the Regional Load Despatch Centre of the region where point of drawal of electricity is situate, shall be the nodal agency for the short-term transmission access. The procedure and modalities in regard to short-term Open Access shall be as per the Central Electricity Regulatory Commission (Open Access in Inter-state Transmission) Regulations, 2004, as amended from time to time.

## **2.3 Role of RPC**

2.3.1 RPCs have been constituted by resolutions dated 25.5.2005 of Central Government for the specified Region(s) for facilitating the integrated operation of the power system in the Region. The Secretariat of the Board is headed by the Member Secretary who is appointed by the Central Electricity Authority (CEA), together with the other staff for the RPC Secretariat. Under section 29(4) of the Electricity Act,2003, the Regional Power Committee in the region may, from time to time, agree on matters concerning the stability and smooth operation of the integrated grid and economy and efficiency in the operation of the power system in that region.

2.3.2 The following functions which go to facilitate the stability and smooth operation of the systems are identified for the RPC:

- i) To undertake Regional Level operation analysis for improving grid performance.
- ii) To facilitate inter-state/inter-regional transfer of power.
- iii) To facilitate all functions of planning relating to inter-state/ intra-state transmission system with CTU/STU.
- iv) To coordinate planning of maintenance of generating machines of various generating companies of the region including those of inter-state generating companies supplying electricity to the Region on annual basis and also to undertake review of maintenance programmed on monthly basis.
- v) To undertake planning of outage of transmission system on monthly basis.
- vi) To undertake operational planning studies including protection studies for stable operation of the grid.
- vii) To undertake planning for maintaining proper voltages through review of reactive compensation requirement through system study committee and monitoring of installed capacitors.
- viii) To evolve consensus on all issues relating to economy and efficiency in the operation of power system in the region.

2.3.3 The decision of RPC arrived at by consensus regarding operation of the regional grid and scheduling and dispatch of electricity will be followed by RLDC subject to directions of the Central Commission, if any.

2.3.4 All complaints regarding unfair practices, delays, discrimination, lack of information, supply of wrong information or any other matter related to open access in inter-state transmission shall be directed to the Member Secretary, RPC of the region in which the authority against whom the complaint is made, is located. The Member Secretary, RPC shall investigate and endeavour to resolve the grievance. In case the Member Secretary, RPC is unable to resolve the matter, it shall be reported to the Central Commission for a decision.

2.3.5 Member Secretary, RPC shall, for the purpose of payment of transmission charges/ capacity charges and incentives, certify:

- (1) Availability of Regional AC and HVDC transmission system
- (2) Availability and Plant Load Factor for ISGS (Thermal)
- (3) Capacity Index for ISGS (Hydro)

## **2.4 Role of CTU**

2.4.1 As per the section 38 of Electricity Act, 2003, the functions of the Central Transmission Utility (CTU) shall be –

- (1) (a) to undertake transmission of electricity through inter-State transmission system;
- (b) to discharge all functions of planning and co-ordination relating to inter-State transmission system with-

- i) State Transmission Utilities
  - ii) Central Government;
  - iii) State Governments;
  - iv) Generating companies;
  - v) Regional Power Committees;
  - vi) Authority;
  - vii) Licensees;
  - viii) Any other person notified by the Central Government in this behalf;
- (c) to ensure development of an efficient, co-ordinated and economical system of inter-State transmission lines for smooth flow of electricity from generating stations to the load centres;
- (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 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 Central Commission .
- (2) Until a Government company or authority or corporation is notified by the Central Government, the Central Transmission Utility shall operate the Regional Load Despatch Centre.

2.4.2 CTU shall not engage in the business of generation of electricity or trading in electricity.

2.4.3 In case of Open access in Inter-state Transmission, the nodal agency for the long-term transmission access shall be the Central Transmission Utility if its system is used. The procedure and modalities in regard to long-term Open Access shall be as per the Central Electricity Regulatory Commission (Open Access in Inter-state Transmission) Regulations, 2004, as amended from time to time.

## **2.5 Role of CEA**

2.5.1 According to the section 73 of Electricity Act, 2003, the functions of CEA as relevant to Grid Code are as under:

- (1) (i) CEA shall formulate short-term and perspective plans for development of the electricity system and co-ordinate the activities of the planing agencies for the optimal utilization of resources to subserve the interests of the national economy and to provide reliable and affordable electricity for all consumers.
- (ii) to specify the technical standards for construction of electrical plants, electric lines and connectivity to the grid ;

- (iii) to specify the safety requirements for construction, operation and maintenance of electrical plants and electric lines;
- (iv) to specify the Grid Standards for operation and maintenance of transmission lines; and,
- (v) to specify the conditions for installation of meters for transmission and supply of electricity.
- (vi) to promote and assist in the timely completion of schemes and projects for improving and augmenting the electricity system;
- (vi) to collect and record the data concerning the generation, transmission, trading, distribution and utilisation of electricity and carry out studies relating to cost, efficiency, competitiveness and such like matters;
- (vii) to carry out, or cause to be carried out, any investigation for the purposes of generating or transmitting or distributing electricity.

- (2) CEA shall prepare a National Electricity Plan in accordance with the National Electricity Policy prepared by the Central Government under the provisions of section 3(1) of Electricity Act, 2003. The CEA shall notify the National Electricity Plan once in five years.

## **2.6 Role of SLDC**

2.6.1 As per section 32 of Electricity Act, 2003, the State Load Despatch Centre (SLDC) shall be the apex body to ensure integrated operation of the power system in a State.

2.6.2 SLDC shall exercise supervision and control over the intra-State transmission system. SLDC will be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the State Grid Code. The SLDC shall comply with the directions of the RLDC.

2.6.3 SLDC shall keep accounts of the quantity of electricity transmitted through the State grid.

### **2.7.1 Role of STU**

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

- (1) (a) to undertake transmission of electricity through intra-State transmission system;
- (b) to discharge all functions of planning and co-ordination relating to intra-State transmission system with-
  - i) Central Transmission Utility;
  - ii) State Governments;
  - iii) generating companies;

- iv) Regional Power Committees;
- v) Authority;
- vi) licensees;
- vii) any other person notified by the State Government in this behalf;

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

(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 .

(2) 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.

## CHAPTER – 3

### PLANNING CODE FOR INTER-STATE TRANSMISSION

This Chapter comprises various aspects of Planning relating to Inter-State transmission systems.

#### 3.1 Introduction

- i) In accordance with Section 38(2)(b) of Electricity Act, 2003, the Central Transmission Utility (CTU) shall discharge all functions of planning and co-ordination relating to inter-State transmission system in co-ordination with State Transmission Utility, Central Government, State Governments, Generating Companies, Regional Power Committees, Central Electricity Authority (CEA), licensees and any other person notified by the Central Government in this behalf.
- ii) In accordance with Section 38(2)(d) of Electricity Act, 2003, the Central Transmission Utility (CTU) 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 Central Commission.
- iii) Similarly, in accordance with Section 39(2)(b) of Electricity Act, 2003, the State Transmission Utilities (STUs) 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.
- iv) In accordance with Section 39(2)(d) of 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.
- v) In accordance with Section 40 of Electricity Act, 2003, the transmission licensee shall inter-alia provide non-discriminatory open access to its transmission system for use by
  - (a) any licensee or generating company on payment of the transmission charges; or

- (b) any consumer as and when such open access is provided by the State Commission under sub-section (2) of Section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.
- vi) In accordance with Section 3 (4) of Electricity Act, 2003, CEA shall sinter-alia prepare a National Electricity Plan in accordance with the National Electricity Policy and notify such plan once in five (5) years. As per Section 3 (5) of Electricity Act, 2003, CEA may review or revise the National Electricity Plan in accordance with the National Electricity Policy.
- vii) In accordance with Section 73 (a) of 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 subserve the interests of the national economy and to provide reliable and affordable electricity for all consumers.
- viii) The Planning Code specifies the policy and procedures to be applied in planning of Regional Grids and Inter Regional links.

### **3.2 Objective**

The objectives of Planning Code are as follows:

- (a) To specify the principles, procedures and criteria which shall be used in the planning and development of the ISTS and inter regional links.
- (b) To promote co-ordination amongst all Regional Constituents and agencies in any proposed development of the ISTS.
- (c) To provide methodology and information exchange amongst Regional Constituents and agencies in the planning and development of the ISTS.

### **3.3 Scope**

The Planning Code applies to CTU, other Transmission licensees, Inter-State Generating Station (ISGS), connected to and/or using and involved in developing the ISTS. This Planning Code also applies to Generating Companies, IPPs, SEBs/STUs and /licensees, regarding generation and/or transmission of energy to/from the ISTS.

### **3.4 Planning Policy**

- (a) CEA would formulate perspective transmission plan for inter-State transmission system as well as 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.

- (b) The CTU shall carry out planning process from time to time as per the requirement for identification of major inter-State transmission system including inter-regional schemes which shall fit in with the perspective plan developed by CEA. While planning schemes, the following shall be considered in addition to the data of authenticated nature collected from and in consultation with various agencies / Regional Constituents by CTU:
- 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) Reports on National Electricity Policy, issued by Govt. of India which are relevant for development of ISTS.
- (c) In addition to the major inter-State transmission system, the CTU 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. The inter-State transmission proposals including system strengthening scheme identified on the basis of the planning studies would be discussed, reviewed and finalized in the meetings of Regional Standing Committees for Transmission Planning constituted by CEA, in consultation with the beneficiaries, RPC, CEA and the RLDC.
- (d) As per CERC regulation for providing open access in inter-State transmission, the nodal agency for arranging the long-term transmission access to the applicant shall be the CTU, if its system is used and for the short-term transmission access shall be the Regional Load Despatch Centre of the region where point of drawal of electricity is situated.
- (e) In case long-term open access in ISTS cannot be allowed without system strengthening, the applicant may request CTU to carry out system studies to identify strengthening requirement and its cost estimates.
- Further, to provide long-term open access as per the terms and conditions formulated by CERC and CTU from time to time, the application for long-term open access including system strengthening identified by CTU in ISTS shall be discussed and finalized in consultation with other agencies.
- (f) All Constituents and agencies will supply to the CTU, the desired planning data from time to time to enable to formulate and finalize its plan.

- (g) The plan reports shall contain a Chapter on additional transmission requirement which may include not only inter-State transmission lines but also additional equipment such as transformer, capacitors, reactors etc.
- (h) The plan report shall also indicate the action taken to fulfill the additional requirement and actual progress made on new schemes. These reports will be available to any interested party for making investment decision/connection decisions to the ISTS.
- (i) As voltage management plays an important role in inter-state transmission of energy, special attention shall be accorded to planning of capacitors, reactors, SVC and Flexible Alternating Current Transmission Systems (FACTS), etc.
- (j) Based on Plans prepared by the CTU, State Transmission Utilities (STU) shall have to plan their systems to further evacuate power from the ISTS.

In case of Long Term Open Access Applications requiring any strengthening in the intra-State transmission system to absorb/evacuate power beyond ISTS, the applicant shall coordinate with the concerned STU.

- (k) 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 performance. Therefore, the associated intra-State transmission system shall also be discussed and reviewed before implementation during the discussion for finalizing ISTS proposal indicated at 3.4 (c) above.

### **3.5 Planning Criterion**

#### **General Policy**

- (a) The planning criterion are based on the security philosophy on which the ISTS has been planned. The security philosophy may be as per the Transmission Planning Criteria and other guidelines as given by CEA. The general policy shall be as detailed below:
  - i) As a general rule, the ISTS shall be capable of withstanding and be secured against the following contingency outages without necessitating load shedding or rescheduling of generation during Steady State Operation:
    - Outage of a 132 kV D/C line or,
    - Outage of a 220 kV D/C line or,
    - Outage of a 400 kV S/C line or,
    - Outage of single Interconnecting Transformer, or
    - Outage of one pole of HVDC Bipole line, or
    - Outage of 765 kV S/C line.

- ii) The above contingencies shall be considered assuming a pre-contingency system depletion (Planned outage) of another 220 kV D/C line or 400 kV S/C line in another corridor and not emanating from the same substation. All the Generating Units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified.
- (b) The ISTS shall be capable of withstanding the loss of most severe single system infeed without loss of stability.
- (c) Any one of these events defined above shall not cause:
  - i) Loss of supply
  - ii) Prolonged operation of the system frequency below and above specified limits.
  - iii) Unacceptable high or low voltage
  - iv) System instability
  - v) Unacceptable overloading of ISTS elements.
- (d) In all substations (132 kV and above), at least two transformers shall be provided.
- (e) CTU shall carry out planning studies for Reactive Power compensation of ISTS including reactive power compensation requirement at the ISGS's Switchyard.

### **3.6 Planning Data**

- (a) Under this Planning Code, the SEBs/STUs/ISGS/State Generating Companies/IPPs/licensees are to supply two types of data :
  - i) Standard planning data**
  - ii) Detailed planning data**
- (b) Standard Planning data
  - i) Standard planning data consists of details which are expected to be normally sufficient for the CTU to investigate the impact on the ISTS due to User development.
  - ii) Standard planning data covering (a) preliminary project planning data (b) committed project planning data and (c) connected planning data should be furnished by the State Electricity Boards/STU, and Generating companies connected to the ISTS. This data shall be furnished to CTU from time to time in the standard formats supplied by the CTU.
  - iii) The standard formats for submission of this data have been developed and approved by the CERC (August, 2001).

(c) Detailed Planning data

Detailed planning data consist of additional, more detailed data not normally expected to be required by CTU to assess the impact of User development on the ISTS. This data shall be furnished by the Users of ISTS as and when requested by CTU.

**3.7 Implementation of Transmission Plan**

The actual program of implementation of transmission lines, Inter-connecting Transformers, reactors/capacitors and other transmission elements will be determined by CTU in consultation with the concerned agencies. The completion of these works, in the required time frame, shall be ensured by CTU through the concerned agency.

## CHAPTER - 4

### CONNECTION CONDITIONS

#### 4.1 Introduction

The Connection Conditions specify the minimum technical and design criteria which shall be complied with by CTU and any agency connected to, or seeking connection to ISTS. They also set out the procedures by which CTU shall ensure compliance by any agency with the above criteria as pre-requisite for the establishment of an agreed connection.

#### 4.2 Objective

The Connection Conditions are designed to ensure that:

- a) The basic rules for connections are complied with to treat all agencies in a non-discriminatory manner.
- (b) Any new or modified connections, when established, shall neither suffer unacceptable effects due to its connections to ISTS nor impose unacceptable effects on the system of any other connected agency.
- (c) The ownership and responsibility for all the equipments shall be clearly specified in a schedule (site responsibility schedule) for every site, where a connection is made.

#### 4.3 Scope

The Connection conditions apply to all Constituents (CTU, ISGS, SEBs/STUs) and any other agency / licensees connected to and involved in developing the ISTS. This Connection Code also applies to all agencies, which are planning to generate/transmit and/or are generating/ transmitting energy to/from ISTS. The Connection conditions for Generating Units embedded in the intra-State systems, and not connected to the ISTS, shall be finalized by the respective STU/SEB.

#### 4.4 Procedure for connection

- (a) Prior to a agency being connected to the ISTS all necessary conditions outlined in the IEGC in addition to other mutually agreed requirements to be complied with, must be fulfilled by the agency. Any agency seeking to establish new or modified arrangement of connection to or for use of ISTS, shall submit an application on standard format to CTU along with the following details:-
  - i) Report stating the purpose of the proposed connection and/or modification, transmission licensee to whose system connection is proposed connection point, description of apparatus to be connected or modification of the apparatus already connected and beneficiaries of the proposed connection.

- ii) Construction schedule and target completion date.
- iii) Confirmation that the agency shall abide by IEGC, Indian Electricity Rules and various standards including Grid Connectivity Standards made pursuant to the Act.

The CTU shall normally make a formal offer to the agency within a period of one month of the date of receipt of all details. Details of the requirements and procedures will be set out in the offer of a connection to the ISTS and the resulting Connection Agreement with the agency. Upon compliance, CTU shall notify the transmission licensee and the applicant agency that it can be connected to the ISTS.

- (b) However in case of the existing connections between ISTS network and Regional Constituents/ISGS, a relaxation of one year in respect of the connection conditions is allowed so that the present arrangements may continue. The process of re-negotiation of the connection conditions with ISGS/regional constituents should be completed within a period of one year. In case it is determined that the compliance of connection conditions would be delayed further, the CERC may consider further relaxation for which a petition will have to be filed by the concerned constituent along with CTU's recommendation/comments. The cost of modification, if any, shall be borne by the concerned constituent.

#### **4.5 Connection Agreement**

A connection agreement shall include (but not limited), as appropriate, within its terms and conditions, the following:

- i) A condition requiring both parties to comply with the IEGC.
- ii) Details of connection, technical requirements and commercial arrangements.
- iii) Details of any capital expenditure arising from necessary reinforcement or extension of the system, data communication, RTU etc. and demarcation of the same between the concerned parties.
- iv) Site responsibility schedule.
- v) General philosophy, guidelines, etc., on protection and telemetry.

A model connection agreement is placed at Annexure-1 to Chapter-4.

#### **4.6 ISTS Parameter Variations**

##### **(a) General**

Within the power system, instantaneous values of system frequency and voltage are subject to variation from their nominal value. All agencies shall ensure that Plant and Apparatus requiring service from/to the ISTS is of such design and construction that satisfactory operation will not be prevented by such variation.

##### **(b) Frequency Variations**

Rated frequency of the system shall be 50.0 Hz and shall normally be controlled within the limits as per regulations/standards framed by the Authority.

##### **(c) Voltage Variations**

- i) The variation of voltage may not be more than the voltage range specified in the regulations/standards framed by the Authority.
- ii) The agency engaged in sub-transmission and distribution shall not depend upon the ISTS for reactive support when connected. The agency shall estimate and provide the required reactive compensation in its transmission and distribution network to meet its full Reactive Power requirement, unless specifically agreed to with CTU.

#### **4.7 Agency and CTU equipment at Connection Points**

##### **(a) Sub-station Equipment**

- i) All EHV sub-station equipments shall comply with Bureau of Indian Standards ( BIS)/IEC/ prevailing Code of practice.
- ii) All equipment shall be designed, manufactured and tested and certified in accordance with the quality assurance requirements as per IEC/BIS standards.
- iii) Each connection between an agency and ISTS shall be controlled by a circuit breaker capable of interrupting, at the connection point, the short circuit current as advised by CTU in the specific Connection Agreement.

##### **(b) Fault Clearance Times**

- i) The fault clearance time when all equipments operates correctly, for a three phase fault (close to the bus-bars) on agencies equipment directly connected to ISTS and for a three phase fault (close to the bus-bars) on ISTS connected to agencies equipment, shall not be more than:
  - a) 100 milli seconds (ms) for 800 kV class & 400 kV

b) 160 milli seconds (ms) for 220 kV & 132 kV

ii) Back-up protection shall be provided for required isolation/protection in the event of failure of the primary protection systems provided to meet the above fault clearance time requirements. If a Generating Unit is connected to the ISTS directly, it shall withstand, until clearing of the fault by back-up protection on the ISTS side.

(c) **Protection**

Protection systems are required to be provided by all agencies and Constituents connected to the ISTS in coordination with CTU. In case of installation of any device which necessitates modification/ replacement of existing protection relays/ scheme in the network, such modification/ replacement shall be carried out by owner of respective part of network.

Protection systems are required to isolate the faulty equipments and protect the other components against all types of faults, internal/ external to them, within the specified fault clearance time with reliability, selectivity and sensitivity.

All agencies connected to the ISTS shall provide protection systems as specified in the connection agreement.

Relay setting coordination shall be done at regional level by RPC. The RPCs would also identify critical locations where bus bar protection needs to be provided, if not available.

**4.8 Generating Units and Power Stations**

a) A Generating Unit shall be capable of continuously supplying its normal rated active/reactive output within the system frequency and voltage variation range indicated at section 4.6 above, subject to the design imitations specified by the manufacturer.

b) A generating unit shall be provided with an AVR, protective and safety devices, as set out in connection agreements.

c) Each Generating Unit shall be fitted with a turbine speed governor having an overall droop characteristic within the range of 3% to 6% which shall always be in service.

d) Each Generating Unit shall be capable of instantaneously increasing output by 5% when the frequency falls limited to 105% MCR. Ramping back to the previous MW level (in case the increased output level can not be sustained) shall not be faster than 1% per minute.

**4.9 Reactive Power Compensation**

a) Reactive Power compensation and/or other facilities, should be provided by SEBs/STUs and distributing licensees as far as possible



in the low voltage systems close to the load points thereby avoiding the need for exchange of Reactive Power to/from ISTS and to maintain ISTS voltage within the specified range.

- b) Line Reactors may be provided to control temporary over voltage within the limits as set out in connection agreements.
- c) The additional reactive compensation to be provided by the agency shall be indicated by CTU in the Connection Agreement for implementation.

#### **4.10 Data and Communication Facilities**

Reliable and efficient speech and data communication systems shall be provided to facilitate necessary communication and data exchange, and supervision/control of the grid by the RLDC, under normal and abnormal conditions. All agencies shall provide Systems to telemeter power system parameter such as flow, voltage and status of switches/transformer taps etc. in line with interface requirements and other guideline made available to RLDC / SLDC. The associated communication system to facilitate data flow up to RLDC/SLDC, as the case may be, shall also be established by the concerned agency as specified by CTU in connection agreement. All agencies in coordination with CTU shall provide the required facilities at their respective ends and RLDC / SLDC as specified in the connection agreement.

#### **4.11 System Recording Instruments**

Recording instruments such as Data Acquisition System/Disturbance Recorder/Event Logger/Fault Locator (including time synchronization equipment) shall be provided in the ISTS for recording of dynamic performance of the system. Agencies shall provide all the requisite recording instruments as specified in the connection agreement according to the agreed time schedule.

#### **4.12 Responsibilities for operational safety**

CTU/Transmission licensee and the Regional Constituents/agency concerned shall be responsible for safety as indicated in Site Responsibility Schedules for each connection point.

##### **(a) Site Responsibility Schedules**

- i) A Site Responsibility Schedule shall be produced by the CTU/transmission license and agency detailing the ownership responsibilities of each, before execution of the project or connection including safety responsibilities.

For connection to the ISTS a schedule shall be prepared by CTU/transmission licensee pursuant to the relevant Connection Agreement which shall state for each item of plant and apparatus at the connection point the following:

- Ownership of the Plant/Apparatus

- Responsibility for control of the Plant/Apparatus
- Responsibility for operation of the Plant/Apparatus.
- Responsibility for maintenance of the Plant/Apparatus and
- Responsibility for all matters relating to the safety of any person

at the connection point.

- ii) The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules shall be formulated by CTU and shall be provided to each agency/regional constituents for compliance.
- iii) All agencies connected to or planning to connect to ISTS would ensure providing of RTU and other communication equipment, as specified by RLDC/SLDC, for sending real-time data to SLDC/RLDC at least before date of commercial operation of the generating stations or sub-station/line being connected to ISTS.

**(b) Single Line Diagrams**

- i) Single Line Diagram shall be furnished for each Connection Point by the connected agencies to RLDC. These diagrams shall include all HV connected equipment and the connections to all external circuits and incorporate numbering, nomenclature and labelling, etc. The diagram is intended to provide an accurate record of the layout and circuit connections, rating, numbering and nomenclature of HV apparatus and related plant.
- ii) Whenever any equipment has been proposed to be changed, then concerned agency shall intimate the necessary changes to CTU and to all concerned. When the changes are implemented, changed Single Line Diagram shall be circulated by the agency to RLDC/CTU.

**(c) Site Common Drawings**

- i) Site Common Drawing will be prepared for each Connection Point and will include site layout, electrical layout, details of protection and common services drawings. Necessary details shall be provided by the agencies to CTU.
- ii) The detailed drawings for the portion of the agency and CTU/ transmission licensee at each Connection Point shall be prepared individually and copies shall be handed over to other party.
- iii) If any change in the drawing is found necessary, the details will be furnished to other party as soon as possible.

#### **4.13 Procedure for Site Access, Site operational activities and Maintenance Standards**

The Connection Agreement will also indicate any procedure necessary for Site access, Site operational activities and maintenance standard for equipment of the CTU/ transmission licensee at ISGS/SEB/STU/licensee premises and vice versa.

#### **4.14 International Connections to ISTS**

The procedure for international Connection to ISTS and the execution of agreement for the same shall be done by CTU in consultation with CEA and Ministry of Power (MOP).

#### **4.15 Schedule of assets of Regional Grid**

CTU shall submit annually to CERC by 30<sup>th</sup> September each year a schedule of transmission assets, which constitute the Regional Grid as on 31<sup>st</sup> March of that year indicating ownership on which RLDC has operational control and responsibility.

**ANNEXURE-1**  
**(refer section 4.5)**

**MODEL CONNECTION AGREEMENT**

**(TO BE INCLUDED LATER)**

## CHAPTER-5

### OPERATING CODE FOR REGIONAL GRIDS

#### 5.1 Operating Policy

- (a) The primary objective of integrated operation of the Regional grids is to enhance the overall operational economy and reliability of the entire electric power network spread over the geographical area of the interconnected States. Participant utilities shall cooperate with each other and adopt Good Utility Practice at all times for satisfactory and beneficial operation of the Regional grid.
- (b) Overall operation of the Regional grid shall be supervised from the Regional Load Despatch Centre (RLDC). The roles of RLDC and RPC shall be in accordance with the provisions made in Chapter-2 of the IEGC.
- (c) All Regional constituents shall comply with this Operating Code, for deriving maximum benefits from the integrated operation and for equitable sharing of obligations.
- (d) A set of detailed internal operating procedures for each regional grid shall be developed and maintained by the respective RLDC in consultation with the regional constituents and shall be consistent with IEGC to enable compliance with the requirement of this IEGC.
- (e) The control rooms of the RLDC, all SLDCs, power plants, substation of 132 kV and above, and any other control centres of all regional constituents shall be manned round the clock by qualified and adequately trained personnel.

#### 5.2 System Security Aspects

- (a) All Regional constituents shall endeavor to operate their respective power systems and power stations in synchronism with each other at all times, such that the entire system within a Region operates as one synchronized system.
- (b) No part of the grid shall be deliberately isolated from the rest of the Regional grid, except (i) under an emergency, and conditions in which such isolation would prevent a total grid collapse and/or would enable early restoration of power supply, (ii) when serious damage to a costly equipment is imminent and such isolation would prevent it, (iii) when such isolation is specifically instructed by RLDC. Complete synchronization of grid shall be restored as soon as the conditions again permit it. The restoration process shall be supervised by RLDC, as per operating procedures separately formulated.

- (c) No important element of the Regional grid shall be deliberately opened or removed from service at any time, except when specifically instructed by RLDC or with specific and prior clearance of RLDC. The list of such important grid elements on which the above stipulations apply shall be prepared by the RLDC in consultation with the constituents, and be available at RLDC/SLDCs. In case of opening/removal of any important element of the grid under an emergency situation, the same shall be communicated to RLDC at the earliest possible time after the event.
- (d) Any tripping, whether manual or automatic, of any of the above elements of Regional grid shall be precisely intimated by the concerned State LDC/agency to RLDC as soon as possible, say 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.
- (e) All generating units, which are synchronized with the grid, irrespective of their ownership, type and size, shall have their governors in normal operation at all times . If any generating unit of over fifty (50) MW size (10 MW for North-Eastern Region) is required to be operated without its governor in normal operation, the RLDC shall be immediately advised about the reason and duration of such operation. All governors shall have a droop of between 3% and 6%.
- (f) 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. No dead bands and/or time delays shall be deliberately introduced.
- (g) All Generating Units, operating at or up to 100% of their Maximum Continuous Rating (MCR) shall normally be capable of (and shall not in any way be prevented from) instantaneously picking up five per cent (5%) extra load when frequency falls due to a system contingency. The generating units operating at above 100% of their MCR shall be capable of (and shall not be prevented from) going at least up to 105% of their MCR 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 of over fifty (50) MW size (10 MW for NER) not complying with the above requirements, shall be kept in operation (synchronized with the Regional grid) only after obtaining the permission of RLDC. However, a constituent can make up the corresponding short fall in spinning reserve by

maintaining an extra spinning reserve on the other generating units of the constituent.

- (h) 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 49.5 Hz, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability.
- (i) Except under an emergency, or to prevent an imminent damage to a costly equipment, no constituent shall suddenly reduce his generating unit output by more than one hundred (100) MW (20 MW in case of North-Eastern region) without prior intimation to and consent of the RLDC, particularly when frequency is falling or is below 49.0Hz. Similarly, no constituent shall cause a sudden increase in its load by more than one hundred (100 MW) (20 MW in case of North-Eastern region) without prior intimation to and consent of the RLDC.
- (j) All generating units shall normally have their automatic voltage regulators (AVRs) in operation, with appropriate settings. In particular, if a generating unit of over fifty (50) MW (10 MW in case of North-Eastern region) size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be got properly tuned by the respective generating unit owner as per a plan prepared for the purpose by the CTU from time to time. CTU will be allowed to carry out checking of PSS and further tuning it, wherever considered necessary.
- (k) 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 Committee of the RPC.
- (l) All Regional constituents shall make all possible efforts to ensure that the grid frequency always remains within the 49.0 – 50.5 Hz band, the frequency range within which steam turbines conforming to the IEC specifications can safely operate continuously.
- (m) All Regional constituents shall provide automatic under-frequency and df/dt 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 forum, and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency. All Regional constituents shall ensure that the above under-frequency and df/dt

load shedding/islanding schemes are always functional. However, in case of extreme contingencies, these relays may be temporarily kept out of service with prior consent of RLDC. RLDC shall inform RPC Secretariat about instances when the desired load relief is not obtained through these relays in real time operation.

RPC Secretariat shall carry out periodic inspection of the under frequency relays and maintain proper records of the inspection.

- (n) All regional constituents shall also facilitate identification, installation and commissioning of System Protection Schemes (including inter-tripping and run-back) in the power system to protect against situations such as voltage collapse and cascading. Such schemes would be finalized by the concerned RPC forum, and shall be kept in service. RLDC shall be promptly informed in case any of these are taken out of service.
- (o) Procedures shall be developed to recover from partial/total collapse of the grid and periodically updated in accordance with the requirements given under section 5.8. These procedures shall be followed by all the Regional constituents to ensure consistent, reliable and quick restoration.
- (p) Each Regional constituent shall provide adequate and reliable communication facility internally and with other constituents/RLDC 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., SLDC to RLDC.
- (q) The Regional constituents shall send information/data including disturbance recorder/sequential event recorder output etc., to RLDC for purpose of analysis of any grid disturbance/event. No Regional constituent shall block any data/information required by the RLDC for maintaining reliability and security of the grid and for analysis of an event.
- (r) All regional constituents shall make all possible efforts to ensure that the grid voltage always remains within the following operating range.

----- VOLTAGE – (KV rms) -----		
Nominal	Maximum	Minimum
400	420	360
220	245	200
132	145	120
-----		



## **5.3 Demand Estimation for Operational Purposes**

### **5.3.1 Introduction**

- (a) This section describes the procedures/responsibilities of the SLDCs for demand estimation for both Active Power and Reactive Power.
- (b) The demand estimation is to be done on daily/weekly/monthly basis for current year.
- (c) Each SLDC shall carry out its own demand estimation from the historical data and weather forecast data from time to time.
- (d) While the demand estimation for operational purposes is to be done on a daily/weekly/monthly basis initially, mechanisms and facilities at SLDCs shall be created at the earliest to facilitate on-line estimation for daily operational use.

### **5.3.2 Objective**

- (a) The objective of this procedure is to enable the SLDCs to estimate their demand over a particular period.
- (b) The demand estimates are to enable the SLDC to conduct system studies for operational planning purposes.

### **5.3.3 Procedure**

Each State/SLDC shall develop methodologies/mechanisms for daily/weekly/monthly/yearly demand estimation (MW, MVar and MWh) for operational purposes. The data for the estimation shall also include load shedding, power cuts, etc. SLDCs shall also maintain historical database for demand estimation.

## **5.4 Demand Management**

### **5.4.1 Introduction**

This section is concerned with the provisions to be made by SLDCs to effect a reduction of demand in the event of insufficient generating capacity, and transfers from external interconnections being not available to meet demand, or in the event of breakdown or operating problems (such as frequency, voltage levels or thermal overloads) on any part of the grid.

## **5.4.2 Manual Demand Disconnection**

- (a) As mentioned elsewhere, the constituents shall endeavour to restrict their net drawal from the grid to within their respective drawal schedules whenever the system frequency is below 49.5 Hz. When the frequency falls below 49.0 Hz, requisite load shedding (manual) shall be carried out in the concerned State to curtail the over-drawal.
- (b) Further, in case of certain contingencies and/or threat to system security, the RLDC may direct an SLDC to decrease its drawal by a certain quantum. Such directions shall immediately be acted upon.
- (c) Each Regional constituent shall make arrangements that will enable manual demand disconnection to take place, as instructed by the RLDC/SLDC, under normal and/or contingent conditions.
- (d) The measures taken to reduce the constituents' drawal from the grid shall not be withdrawn as long as the frequency/voltage remains at a low level, unless specifically permitted by the RLDC.

## **5.5 Periodic Reports**

**5.5.1** A weekly report shall be issued by RLDC to all constituents of the Region and RPC Secretariat and shall cover the performance of the Regional grid for the previous week. Such weekly report shall also be available on the website of the RLDC concerned for at least 12 weeks.

- The weekly report shall contain the following:-
- (a) Frequency profile
  - (b) Voltage profile of selected substations
  - (c) Major Generation and Transmission Outages
  - (d) Transmission Constraints
  - (e) Instances of persistent/significant non-compliance of IEGC.

### **5.5.2 Other Reports**

- (a) The RLDC shall prepare a quarterly report which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of various actions taken by different agencies, and the agencies responsible for causing the constraints.
- (b) The RLDC shall also provide information/report which can be called for by RPC in the interest of smooth operation of ISTS.

## **5.6 Operational Liaison**

### **5.6.1 Introduction**

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

1. The Regional grid
2. The ISTS in the Region
3. The system of a Regional constituent

The above generally relates to notifying of what is expected to happen or what has happened and not the reasons why.

(b) The Operational liaison function is a mandatory built-in hierarchical function of the RLDC and Regional constituents, to facilitate quick transfer of information to operational staff. It will correlate the required inputs for optimization of decision making and actions.

### **5.6.2 Procedure for Operational Liaison**

(a) Operations and events on the Regional grid

- Before any Operation is carried out on Regional grid, the RLDC will inform each Regional constituent, whose system may, or will, experience an operational effect, and give details of the operation to be carried out.
- Immediately following an event on Regional grid, the RLDC will inform each Regional Constituent, whose system may, or will, experience an operational effect following the event, and give details of what has happened in the event but not the reasons why.

(b) Operations and events on a Constituent's system.

- Before any operation is carried out on a constituent's system, the constituent will inform the RLDC, in case the Regional grid may, or will, experience an Operational effect, and give details of the operation to be carried out.
- Immediately following an event on a constituent's system, the constituent will inform the RLDC, in case the Regional grid may, or will, experience an operational effect following the event, and give details of what has happened in the event but not the reasons why.

## **5.7 Outage Planning**

### **5.7.1 Introduction**

- a) This section sets out the procedure for preparation of outage schedules for the elements of the Regional 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 RLDC and SLDCs).
- 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 shall be prepared in advance for the financial year by the RPC Secretariat and reviewed during the year on quarterly and Monthly basis.

### **5.7.2 Objective**

- a) To produce a coordinated generation outage programme for the Regional 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 optimize the transmission outages of the elements of the Regional grid without adversely affecting the grid operation but taking into account the Generation Outage Schedule, outages of SEB/STU systems and maintaining system security standards.

### **5.7.3 Scope**

This section is applicable to all Regional constituents including RLDC, SLDCs, SEBs/STUs, ISGS and CTU.

### **5.7.4 Outage Planning Process**

- a) The RPC Secretariat shall be responsible for analyzing the outage schedule given by all Regional Constituents, preparing a draft annual outage schedule and finalization of the annual outage plan for the following financial year by 31<sup>st</sup> January of each year.

- b) All SEBs/STUs, CTU, ISGS shall provide RPC Secretariat their proposed outage programmes in writing for the next financial year by 30<sup>th</sup> November of each year. These shall contain identification of each generating unit/line/ICT, the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date.
- c) RPC Secretariat shall then come out with a draft outage programme for the next financial year by 31<sup>st</sup> December of each year for the Regional grid taking into account the available resources in an optimal manner and to maintain security standards. This will be done after carrying out necessary system studies and, if necessary, the outage programmes shall be rescheduled. Adequate balance between generation and load requirement shall be ensured while finalising outage programmes.
- d) The final outage plan shall be intimated to all Regional constituents and the RLDC for implementation latest by 31<sup>st</sup> January of each year as mutually decided in RPC forum.
- e) The above annual outage plan shall be reviewed by RPC Secretariat 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, RLDC may conduct studies again before clearance of the planned outage.
- g) RLDC is authorized to defer the planned outage in case of any of the following, taking into account the statutory requirements:
  - i. Major grid disturbances (Total black out in Region)
  - ii. System isolation
  - iii. Black out in a constituent 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 Regional constituent shall obtain the final approval from RLDC prior to availing an outage.

## **5.8 Recovery Procedures**

- a) Detailed plans and procedures for restoration of the regional grid under partial/total blackout shall be developed by RLDC in consultation with all Regional constituents/RPC Secretariat and shall be reviewed / updated annually.

- b) Detailed plans and procedures for restoration after partial/total blackout of each Constituents' system within a Region, will be finalized by the concerned constituent 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 sub-systems shall be carried out by the constituents at least once every six months under intimation to the RLDC.
- c) List of generating stations with black start facility, inter-State/inter regional ties, synchronizing points and essential loads to be restored on priority, shall be prepared and be available with RLDCs.
- d) The RLDC 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.
- e) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

## **5.9 Event Information**

### **5.9.1 Introduction**

This session deals with reporting procedures in writing of reportable events in the system to all Regional constituents, RPC Secretariat and RLDC/SLDC.

### **5.9.2 Objective**

The objective of this section is to define the incidents to be reported, the reporting route to be followed and information to be supplied to ensure consistent approach to the reporting of incidents/events.

### **5.9.3 Scope**

This section covers all Regional constituents, RPC Secretariat, RLDCs and SLDCs.

### **5.9.4 Responsibility**

- a) The RLDC/SLDCs shall be responsible for reporting events to the Regional constituents/RLDC/RPC Secretariat.
- b) All Regional constituents and the SLDCs shall be responsible for collection and reporting of all necessary data to RLDC and RPC Secretariat for monitoring, reporting and event analysis.

### 5.9.5 Reportable Events

Any of the following events require reporting by RLDC/Regional constituent:

- i) Violation of security standards.
- ii) Grid indiscipline.
- iii) Non-compliance of RLDC's instructions.
- iv) System islanding/system split
- v) Regional black out/partial system black out
- vi) Protection failure on any element of ISTS, and on any item on the "agreed list" of the intra-State systems.
- vii) Power system instability
- viii) Tripping of any element of the Regional grid.

### 5.9.6 Reporting Procedure

- (a) Written reporting of Events by Regional Constituents to RLDC:  
In the case of an event which was initially reported by a Regional constituent or a SLDC to RLDC orally, the constituent/SLDC will give a written report to RLDC in accordance with this section.
- (b) Written Reporting of Events by RLDC to Regional Constituents.  
In the case of an event which was initially reported by RLDC to a constituent/SLDC orally, the RLDC will give a written weekly report to the constituent/SLDC in accordance with this section.
- (c) Form of Written Reports:

A written report shall be sent to RLDC or a Regional constituent/SLDC, as the case may be, and will confirm the oral notification together with the following details of the event:

- i) Time and date of event
- ii) Location
- iii) Plant and/or Equipment directly involved
- iv) Description and cause of event
- v) Antecedent conditions
- vi) Demand and/or Generation (in MW) interrupted and duration of interruption
- vii) All Relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, DAS etc.
- viii) Sequence of trippings with time.
- ix) Details of Relay Flags.
- x) Remedial measures.

## **CHAPTER-6**

### **SCHEDULING AND DISPATCH CODE**

#### **6.1 Introduction**

This Chapter sets out the

- a) Demarcation of responsibilities between various Regional constituents and RLDC in scheduling and dispatch
- b) the procedure for scheduling and dispatch
- c) the reactive power and voltage control mechanism
- d) complementary commercial mechanisms (in the Annexure– 1).

#### **6.2 Objective**

This code deals with the procedures to be adopted for scheduling of the inter-State generating stations (ISGS) and net drawals of concerned constituents on a daily basis with the modality of the flow of information between the ISGS/RLDCs/beneficiaries of the Region. The procedure for submission of capability declaration by each ISGS and submission of drawal schedule by each beneficiary is intended to enable RLDCs to prepare the dispatch schedule for each ISGS and drawal schedule for each beneficiary. It also provides methodology of issuing real time dispatch/drawal instructions and rescheduling, if required, to ISGS and beneficiaries along with the commercial arrangement for the deviations from schedules, as well as, mechanism for reactive power pricing. The provisions contained in this chapter are without prejudice to the powers conferred on RLDC under section 28 and 29 of the Electricity Act, 2003.

#### **6.3 Scope**

This code will be applicable to RLDC/SLDCs, ISGS, SEBs/STUs and other beneficiaries in the Regional grid.

The scheduling and dispatch procedure for the generating stations of Bhakra Beas Management Board (BBMB) shall be separately formulated by the Northern Regional Load Dispatch Centre (NRLDC) in consultation with BBMB.

Similarly, the scheduling and dispatch procedure for the generating stations of Sardar Sarover Project (SSP) shall be separately formulated by the Western Regional Load Dispatch Centre (WRLDC) in consultation with Sardar Sarover Narmada Nigam Ltd (SSNNL) /Narmada Control Authority (NCA).



## **6.4 Demarcation of responsibilities**

1. The Regional grids shall be operated as loose power pools (with decentralized scheduling and dispatch), in which the States shall have full operational autonomy, and SLDCs shall have the total responsibility for (i) scheduling/dispatching their own generation (including generation of their embedded licensees), (ii) regulating the demand of their customers, (iii) scheduling their drawal from the ISGS (within their share in the respective plant's expected capability), (iv) arranging any bilateral interchanges, and (v) regulating their net drawal from the regional grid as per following guidelines.

2. The system of each State shall be treated and operated as a notional control area. The algebraic summation of scheduled drawal from ISGS and any bilateral inter-change shall provide the drawal schedule of each State, and this shall be determined in advance on daily basis. While the States would generally be expected to regulate their generation and/or consumers' load so as to maintain their actual drawal from the regional grid close to the above schedule, a tight control is not mandated. The States may, at their discretion, deviate from the drawal schedule, as long as such deviations do not cause system parameters to deteriorate beyond permissible limits and/or do not lead to unacceptable line loading.

3. The above flexibility has been proposed in view of the fact that all States do not have all requisite facilities for minute-to-minute on-line regulation of the actual net drawal from the regional grid. Deviations from net drawal schedule are however, to be appropriately priced through the Unscheduled Interchange (UI) mechanism.

4. Provided that the States, through their SLDCs, shall always endeavour to restrict their net drawal from the grid to within their respective drawal schedules, whenever the system frequency is below 49.5 Hz. When the frequency falls below 49.0 Hz, requisite load shedding shall be carried out in the concerned State(s) to curtail the over-drawal.

5. The SLDCs/STUs shall regularly carry out the necessary exercises regarding short-term and long-term demand estimation for their respective States, to enable them to plan in advance as to how they would meet their consumers' load without overdrawing from the grid.

6. The ISGS shall be responsible for power generation generally according to the daily schedules advised to them by the RLDC on the

basis of the requisitions received from the SLDCs, and for proper operation and maintenance of their generating stations, such that these stations achieve the best possible long-term availability and economy.

7. While the ISGS would normally be expected to generate power according to the daily schedules advised to them, it would not be mandatory to follow the schedules tightly. In line with the flexibility allowed to the States, the ISGS may also deviate from the given schedules depending on the plant and system conditions. In particular, they would be allowed / encouraged to generate beyond the given schedule under deficit conditions. Deviations from the ex-power plant generation schedules shall, however, be appropriately priced through the UI mechanism.

8. Provided that when the frequency is higher than 50.5 Hz, the actual net injection shall not exceed the scheduled dispatch for that time. Also, while the frequency is above 50.5 Hz, the ISGS may (at their discretion) back down without waiting for an advice from RLDC to restrict the frequency rise. When the frequency falls below 49.5 Hz, the generation at all ISGS (except those on peaking duty) shall be maximized, at least upto the level which can be sustained, without waiting for an advise from RLDC.

9. However, notwithstanding the above, the RLDC may direct the SLDCs/ISGS 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 RLDC has some time for analysis, it shall be checked whether the situation has arisen due to deviations from schedules, or due to any power flows pursuant to short-term open access. These shall be got terminated first, in the above sequence, before an action which would affect the scheduled supplies from ISGS to the long term customers is initiated.

10. For all outages of generation and transmission system, which may have an effect on the regional grid, all constituents shall cooperate with each other and coordinate their actions 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 a beneficiary can receive (and which may have a commercial implication) shall be planned carefully to achieve the best optimization.

11. The regional constituents shall enter into separate joint/bilateral agreement(s) to identify the State's shares in ISGS projects (based on the

allocations by the Govt. of India, where applicable), scheduled drawal pattern, tariffs, payment terms etc. All such agreements shall be filed with the concerned RLDC(s) and RPC Secretariat, for being considered in scheduling and regional energy accounting. Any bilateral agreements between constituents for scheduled interchanges on long-term/short-term basis shall also specify the interchange schedule, which shall be duly filed in advance with the RLDC.

12. All constituents should abide by the concept of frequency-linked load dispatch and pricing of deviations from schedule, i.e., unscheduled interchanges. All generating units of the constituents, their licensees and generating companies should normally be operated according to the standing frequency-linked load dispatch guidelines issued by the RLDC, to the extent possible, unless otherwise advised by the RLDC/SLDC.

13. It shall be incumbent upon the ISGS 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 RLDC may ask the ISGS to explain the situation with necessary backup data.

14. The CTU shall install special energy meters on all inter connections between the regional constituents and other identified points for recording of actual net MWh interchanges and MVA<sub>rh</sub> drawals. The type of meters to be installed, metering scheme, metering capability, testing and calibration requirements and the scheme for collection and dissemination of metered data are detailed in the enclosed Annexure-2. All concerned entities (in whose premises the special energy meters are installed) shall fully cooperate with the CTU/RLDC and extend the necessary assistance by taking weekly meter readings and transmitting them to the RLDC.

15. The RLDC shall be responsible for computation of actual net MWh injection of each ISGS and actual net drawal of each beneficiary, 15 minute-wise, based on the above meter readings and for preparation of the Regional Energy Accounts. All computations carried out by RLDC shall be open to all constituents for checking/verifications for a period of 15 days. In case any mistake/omission is detected, the RLDC shall forthwith make a complete check and rectify the same.

16. RLDC shall periodically review the actual deviation from the dispatch and net drawal schedules being issued, to check whether any of the constituents are indulging in unfair gaming or collusion. In case any

such practice is detected, the matter shall be reported to the Member Secretary, RPC for further investigation/action.

17. In case the State in which an ISGS is located has a predominant share in that ISGS, the concerned parties may mutually agree (for operational convenience) to assign the responsibility of scheduling of the ISGS to the state's LDC. The role of the concerned RLDC, in such a case, shall be limited to consideration of the schedule for inter-state exchange of power on account of this ISGS while determining the net drawal schedules of the respective states.

**6.5 Scheduling and Dispatch procedure** (to be read with provisions on 'scheduling' in CERC Notification dated 26.03.2004):

1. All inter-State generating stations (ISGS), in whose output more than one State has an allocated/contracted share, shall be duly listed. The station capacities and allocated/contracted shares of different beneficiaries shall also be listed out.

2. Each State shall be entitled to a MW dispatch 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 hydro-electric stations, there would also be a limit on daily MWh dispatch, equal to (MWh generation capacity for the day) x (State's share in the station's capacity).

3. By 9 AM every day, the ISGS shall advise the concerned RLDC, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 0000 hrs to 2400 hrs of the following day.

4. The above information of the foreseen capabilities of the ISGS and the corresponding MW and MWh entitlements of each State, shall be compiled by the RLDC every day for the next day, and advised to all beneficiaries by 10 AM. The SLDCs shall review it vis-à-vis their foreseen load pattern and their own generating capability including bilateral exchanges, if any, and advise the RLDC by 3 PM their drawal schedule for each of the ISGS in which they have shares, long-term bilateral interchanges, approved short-term bilateral interchanges and composite request for day-ahead open access and scheduling of bilateral interchanges.

5. The SLDCs may also give standing instructions to the RLDC such that the RLDC itself may decide the drawal schedules for the States.

6. By 5 PM each day, the RLDC shall convey:
- i) the ex-power plant “dispatch schedule” to each of the ISGS, in MW for different hours, for the next day. The summation of the ex-power plant drawal schedules advised by all beneficiaries shall constitute the ex-power plant station-wise dispatch schedule.
  - ii) The “net drawal schedule” to each beneficiary, in MW for different hours, for the next day. The summation of the station-wise ex-power plant drawal schedules for all ISGS and drawal from regional grid consequent to bilateral interchanges, after deducting the transmission losses (estimated), shall constitute the State-wise drawal schedule.

7. While finalizing the above daily dispatch schedules for the ISGS, RLDC 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. A ramping rate of upto 200 MW per hour should generally be acceptable for an ISGS and for a regional constituent (50 MW in NER), except for hydro-electric generating stations which may be able to ramp up/ramp down at a faster rate.

8. The SLDCs/ISGS may inform any modifications/changes to be made in station-wise drawal schedule & bilateral interchanges /foreseen capabilities, if any, to RLDC by 10 PM.

9. Upon receipt of such information, the RLDC after consulting the concerned constituents, shall issue the final ‘drawal schedule’ to each SLDC and the final ‘dispatch schedule’ to each ISGS by 11 PM.

10. Also, based on the surpluses foreseen for the next day, if any, the constituents may arrange for bilateral exchanges. The schedules for such arrangements shall be intimated latest by 10 PM to RLDC, who in turn will take into account these agreed exchanges while issuing the final dispatch/drawal schedules at 11 PM provided they would not lead to a transmission constraint.

11. While finalizing the drawal and dispatch schedules as above, the RLDC shall also check that the resulting power flows do not give rise to any transmission constraints. In case any constraints are foreseen, the RLDC shall moderate the schedules to the required extent, under intimation to the concerned constituents. 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 RLDC.

12. In case of forced outage of a unit, the RLDC shall revise the schedules on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the 4th time block, counting the time block in which the revision is advised by the ISGS to be the first one.

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 sub-stations owned by the Central Transmission Utility or any other transmission licensee involved in interstate transmission (as certified by the RLDC) necessitating reduction in generation, the RLDC shall revise the schedules which shall become effective from the 4th 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 ISGS 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 to be equal to their actual drawals.

14. In case of any grid disturbance, scheduled generation of all the ISGS and scheduled drawal of all the beneficiaries 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 RLDC.

15. Revision of declared capability by the ISGS(s) and requisition by beneficiary(ies) 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 6th time block, counting the time block in which the request for revision has been received in the RLDC to be the first one.

16. If, at any point of time, the RLDC 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 4th time block, counting the time block in which the revised schedule is issued by the RLDC to be the first one.

17. To discourage frivolous revisions, an RLDC may, at its sole discretion, refuse to accept schedule/capability changes of less than two (2) percent of the previous schedule/capability.

18. After the operating day is over at 2400 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in dispatch schedule of generating stations and drawal schedule of the States) shall be issued by RLDC. These schedules shall be the datum for commercial accounting. The average ex-bus capability for each ISGS shall also be worked out based on all before-the-fact advise to RLDC.

19. RLDC shall properly document all above information i.e. station-wise foreseen ex-power plant capabilities advised by the generating stations, the drawal schedules advised by beneficiaries, all schedules issued by the RLDC, and all revisions/updating of the above.

20. The procedure for scheduling and the final schedules issued by RLDC, shall be open to all constituents for any checking/verification, for a period of 5 days. In case any mistake/omission is detected, the RLDC shall forthwith make a complete check and rectify the same.

21. While availability declaration by ISGS may have a resolution of one (1) MW and one (1) MWh, all entitlements, requisitions and schedules shall be rounded off to the nearest decimal, to have a resolution of 0.1 MW.

## **6.6 Reactive Power and Voltage Control**

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 EHV grid, particularly under low-voltage condition. However, considering the present limitations, this is not being insisted upon. Instead, to discourage VAR drawals by Beneficiaries, VAR exchanges with ISTS shall be priced as follows:

- The Beneficiary pays for VAR drawal when voltage at the metering point is below 97%
- The Beneficiary gets paid for VAR return when voltage is below 97%
- The Beneficiary gets paid for VAR drawal when voltage is above 103%

- The Beneficiary pays for VAr return when voltage is above 103%

Provided that there shall be no charge/payment for VAr drawal/return by a Beneficiary on its own line emanating directly from an ISGS.

2. The charge/payment for VAr, shall be at a nominal paise/kVArh rate as may be specified by CERC from time to time, and will be between the Beneficiary and the regional pool account for VAr interchanges.

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

4. 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 rated, and shall not return VAr when the voltage is above 105%. ICT taps at the respective drawal points may be changed to control the VAr interchange as per a Beneficiary's request to the RLDC, but only at reasonable intervals.

5. Switching in/out of all 400 kV bus and line Reactors throughout the grid shall be carried out as per instructions of RLDC. Tap changing on all 400/220 kV ICTs shall also be done as per RLDCs instructions only.

6. The ISGS shall generate/absorb reactive power as per instructions of RLDC, within capability limits of the respective generating units, that is without sacrificing on the active generation required at that time. No payments shall be made to the generating companies for such VAr generation/absorption.

7. VAr exchange directly between two Beneficiaries on the interconnecting lines owned by them (singly or jointly) generally address or cause a local voltage problem, and generally do not have an impact on the voltage profile of the regional 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.



- iii) 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 CERC for VAr exchanges with ISTS. If the agreed scheme requires any additional metering, the same shall be arranged by the concerned Beneficiaries.
  
- iv) 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-3 shall be applied. The per kVArh rate shall be as specified by CERC for VAr exchanges with ISTS.
  
- iv) The computation and payments for such VAr exchanges shall be effected as mutually agreed between the two Beneficiaries.

**COMPLEMENTARY COMMERCIAL MECHANISMS**

1. The beneficiaries shall pay to the respective ISGS Capacity charges corresponding to plant availability and Energy charges for the scheduled dispatch, as per the relevant notifications and orders of CERC. The bills for these charges shall be issued by the respective ISGS to each beneficiary on monthly basis.
  
2. The sum of the above two charges from all beneficiaries shall fully reimburse the ISGS for generation according to the given dispatch schedule. In case of a deviation from the dispatch schedule, the concerned ISGS shall be additionally paid for excess generation through the UI mechanism approved by CERC. In case of actual generation being below the given dispatch schedule, the concerned ISGS shall pay back through the UI mechanism for the shortfall in generation.
  
3. The summation of station-wise ex-power plant dispatch schedules from each ISGS and any bilaterally agreed interchanges of each beneficiary shall be adjusted for transmission losses, and the net drawal schedule so calculated shall be compared with the actual net drawal of the beneficiary. In case of excess drawal, the beneficiary shall be required to pay through the UI mechanism for the excess energy. In case of under-drawal, the beneficiary shall be paid back through the UI mechanism, for the energy not drawn.
  
4. When requested by a constituent, RLDC shall assist the constituent in locating a buyer/seller and arranging a scheduled interchange within the Region or across the regional boundary. The RLDC shall act only as a facilitator (not a trader / broker), and shall assume no liabilities under the agreement between the two parties, except (i) ascertaining that no component of the power system of any other constituent shall be overstressed by such interchange/trade, and (ii) incorporating the agreed interchange/trade in the net interchange schedules for the concerned constituents.
  
5. Regional Energy Accounts and the statement of UI charges shall be prepared by the RLDC on a weekly basis and these shall be issued to all constituents by Saturday for the seven-day period ending on the previous Sunday mid-night. Payment of UI charges shall have a high priority and the concerned constituents shall pay the indicated amounts within 10 (ten) days of the statement issue into a regional UI pool account operated by the RLDC. The agencies who have to receive the money on account of UI

charges would then be paid out from the regional UI pool account, within three (3) working days.

6. The RLDC shall also issue the weekly statement for VAr charges, to all constituents who have a net drawal/injection of reactive energy under low/high voltage conditions. These payment shall also have a high priority and the concerned constituents shall pay the indicated amounts into regional reactive account operated by the RLDC within 10 (ten) days of statement issue. The constituents who have to receive the money on account of VAr charges would then be paid out from the regional reactive account, within three (3) working days.

7. If payments against the above UI and VAr charges are delayed by more than two days, i.e., beyond twelve (12) days from statement issue, the defaulting constituent shall have to pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the constituents who had to receive the amount, payment of which got delayed. Persistent payment defaults, if any, shall be reported by the RLDC to the Member Secretary, RPC, for initiating remedial action.

8. The money remaining in the regional reactive account after pay-out of all VAr charges upto 31<sup>st</sup> March of every year shall be utilized for training of the SLDC operators, and other similar purposes which would help in improving/streamlining the operation of the respective regional grids, as decided by the respective RPC from time to time.

9. In case the voltage profile of a regional grid improves to an extent that the total pay-out from the regional VAr charges account for a week exceeds the total amount being paid-in for that week, and if the regional reactive account has no balance to meet the deficit, the pay-outs shall be proportionately reduced according to the total money available in the above account.

10. The RLDC shall table the complete statement of the regional UI account and the regional Reactive Energy account in the RPC's Commercial Committee meeting, on a quarterly basis, for audit by the latter.

11. All 15-minute energy figures (net scheduled, actually metered and UI) shall be rounded off to the nearest 0.01 MWh.

**REGULATORY REQUIREMENTS OF SPECIAL ENERGY METERS**

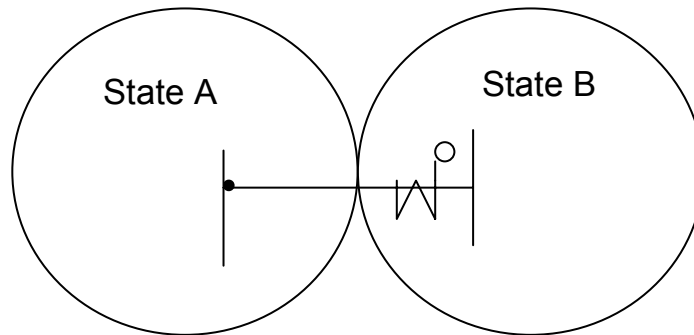
1. Special energy meters of a uniform technical specification shall be provided on the electrical periphery of each regional constituent, to determine its actual net interchange with the regional grid. Each interconnection shall have one (1) Main meter. In addition, Standby/check meters shall be provided such that correct computation of net interchange of a constituent is possible even when a Main meter, a CT or a VT has a problem.
2. The Special energy meters shall be static type, composite meters, installed circuit-wise, as self-contained devices for measurement of active and reactive energy, and certain other parameters as described in the following paragraphs. The meters shall be suitable for being connected directly to voltage transformers (VTs) having a rated secondary line-to-line voltage of 110 V, and to current transformers (CTs) having a rated secondary current of 1A (model-A) or 5A (model-B). The reference frequency shall be 50 Hz.
3. The meters shall have a non-volatile memory in which the following shall be automatically stored:
  - i) Average frequency for each successive 15-minute block, as a two digit code (00 to 99 for frequency from 49.0 to 51.0 Hz).
  - ii) Net Wh transmittal during each successive 15-minute block, upto second decimal, with plus/minus sign.
  - iii) Cumulative Wh transmittal at each midnight, in six digits including one decimal.
  - iv) Cumulative VARh transmittal for voltage high condition, at each midnight, in six digits including one decimal.
  - v) Cumulative VARh transmittal for voltage low condition, at each midnight, in six digits including one decimal.
  - vi) Date and time blocks of failure of VT supply on any phase, as a star (\*) mark.
4. The meters shall store all the above listed data in their memories for a period of ten (10) days. The data older than (10) days shall get erased automatically. Each meter shall have an optical port on its front for tapping all data stored in its memory using a hand held data collection device.

5. The active energy (Wh) measurement shall be carried out on 3-phase, 4-wire principle, with an accuracy as per class 0.2 S of IEC-687/IEC-62053-22. In model-A, the energy shall be computed directly in CT and VT secondary quantities, and indicated in watt-hours. In model-B, the energy display and recording shall be one fifth of the Wh computed in CT and VT secondary quantities.
6. The VAR and reactive energy measurement shall also be on 3-phase, 4-wire principle, with an accuracy as per class 2 of IEC-62053-23 or better. In model-A, the VAR and VARh computation shall be directly in CT and VT secondary quantities. In model-B, these shall be displayed and recorded as one-fifth of those in CT and VT secondary quantities. There shall be two reactive energy registers, one for the period when average RMS voltage is above 103% and the other for the period the voltage is below 97%.
7. The 15-minute Wh shall have a +ve sign when there is a net Wh export from substation busbars, and a -ve sign when there is a net Wh import. The integrating (cumulative) registers for Wh and VARh shall move forward when there is Wh/VARh export from substation busbars, and backward when there is an import.
8. The meters shall also display (on demand), by turn, the following parameters:
  - i) Unique identification number of the meter
  - ii) Date
  - iii) Time
  - iv) Cumulative Wh register reading
  - v) Average frequency of the previous 15-minute block
  - vi) Net Wh transmittal in the previous 15-minute block, with +/- sign
  - vii) Average percentage voltage
  - viii) Reactive power, with +/- sign
  - ix) Voltage-high VARh register reading
  - x) Voltage-low VARh register reading
9. The three line-to-neutral voltages shall be continuously monitored, and in case any of these falls below 70%, the condition shall be suitably indicated and recorded. The meters shall operate with the power drawn from the VT secondary circuits, without the need for any auxiliary power supply. Each meter shall have a built-in calendar and clock, having an accuracy of 30 seconds per month or better.
10. The meters shall be totally sealed and tamper-proof, with no possibility of any adjustment at site, except for a restricted clock correction. The harmonics shall preferably be filtered out while measuring Wh, VAR and VARh, and only fundamental frequency quantities shall be measured/computed.

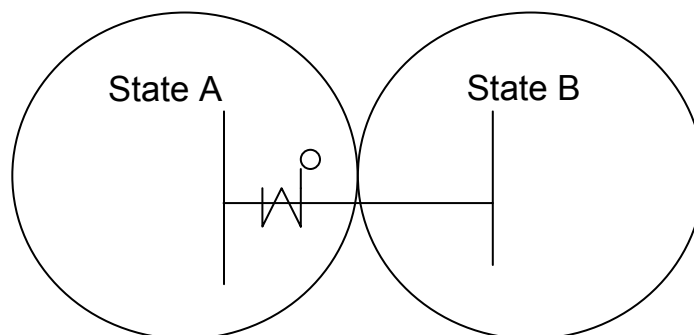
11. All metering equipment shall be of proven quality, fully type-tested, individually tested and accepted by the CTU before dispatch from manufacturer's work.
12. In-situ functional checking and rough testing of accuracy shall be carried out for all meters once a year by the CTU, with portable test equipment complying with IEC-60736, for type and acceptance testing of energy meters of 1.0 class.
13. Full testing for accuracy for every meter shall be carried out by the CTU at an accredited laboratory, once every five (5) years.
14. The current and voltage transformers to which the above special energy meters are connected shall have a measurement accuracy class of 0.5 or better. Main and Standby/check meters shall be connected to different sets of CTs and VTs, wherever available.
15. Only functional requirements from regulatory perspective are given in this code. Detailed specifications for the meters, their accessories and testing, and procedures for collecting their weekly readings shall be finalized by the CTU.

**PAYMENT FOR REACTIVE ENERGY EXCHANGES ON STATE-OWNED LINES**

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



**Case – 2:** Interconnecting line owned by State-B  
Metering point : Substation of State-A

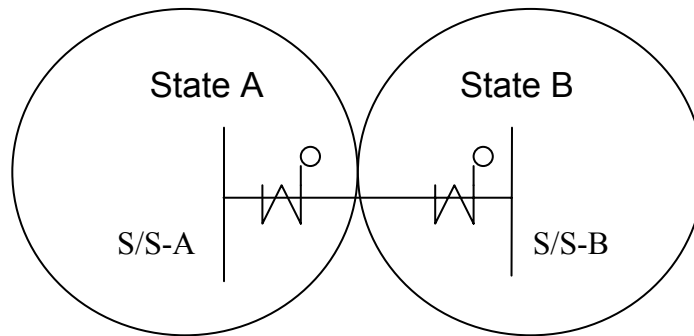


State-B pays to State-A for

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

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

**Case – 3:** Interconnecting line is jointly owned by States-A and –B.  
Metering points : Substations of State-A and State-B



Net VARh exported from S/S-A, while voltage  $< 97\%$  =  $X_1$

Net VARh exported from S/S-A, while voltage  $> 103\%$  =  $X_2$

Net VARh imported at S/S-B, while voltage  $< 97\%$  =  $X_3$

Net VARh imported at S/S-B, while voltage  $> 103\%$  =  $X_4$

(i) State-B pays to State-A for

$X_1$  or  $X_3$ , whichever is smaller in magnitude, and

(ii) State-A pays to State-B for

$X_2$  or  $X_4$ , whichever is smaller in magnitude.

Note:

1. Net VARh and net payment may be positive or negative.
2. In case  $X_1$  is positive and  $X_3$  is negative, or vice-versa, there would be no payment under (i) above.
3. In case  $X_2$  is positive and  $X_4$  is negative, or vice-versa, there would be no payment under (ii) above.



## CHAPTER-7

### INTER-REGIONAL EXCHANGES

#### 7.1 INTRODUCTION

1. India was demarcated into five (5) electrical regions in Sixties, for planning, development and operation of the power system. For over three decades, the generation and transmission planning continued with regional self-sufficiency as an objective/criterion, and consequently the inter-regional links were planned only for marginal exchange of power. Till 2002, the inter-regional links comprised either of 220 kV/132 kV A.C. lines operating in radial mode, or of HVDC back-to-back links, which allowed different regions to operate at their own frequency.
2. The picture has changed dramatically since 2003, with synchronizing of Western, Eastern and North-Eastern regional grids through 400 kV A.C. lines, which enable substantial amounts of power to flow across the regional boundaries. Commissioning of 2000 MW Talcher-Kolar HVDC link between ER and SR, and 500 MW Sasaram HVDC link between ER and NR also facilitate controlled exchange of power between these regions. Many more inter-regional links are planned to be commissioned in the coming years. The special considerations to be applied for operation of these links are set out in this chapter.
3. The stipulations in this chapter may be supplemented by CTU (as operator of RLDCs) depending on operational needs. They may also need revision/updating as and when further inter-regional links come into operation. In due course, this responsibility may be transferred to the CTU, and this chapter withdrawn from IEGC.

#### 7.2 PRESENT SYSTEM

1. India has three (3) synchronous power systems today: (a) Northern, (b) Central (WR-ER-NER), and (c) Southern. The Northern system is connected to Central mainly through two (2) back to back HVDC links: (a) 2x250 MW Vindhyachal (NR-WR), and (b) 1x500 MW Sasaram (ER-NR). The Southern system is connected to Central mainly through three (3) HVDC links: (a) 2x1000 MW Talcher-Kolar (ER-SR), (b) 2x500 MW Gazuwaka (ER-SR), and (c) 2x500 MW Chandrapur (WR-SR).

ER and WR are presently synchronized through the 400 kV D/C Rourkela-Raipur line, and three (3) 220 kV circuits between Budhipadhar and Korba. ER and NER are synchronized through the 400 kV D/C Malda-Purnea/Binaguri-Bongaigaon line and 220 kV D/C Birpara-Salakati line.

2. While power flows on HVDC links can be controlled or set at any required level in either direction, and thereby the exchanges between Northern and Central, and between Southern and Central can be

controlled directly, the power inter-changes between West, East and North-East depend on relative load-generation balances in the three regions.

### **7.3 SCHEDULING OF ISGS**

1. All ISGS, except Talcher-II STPS, shall be scheduled through the RLDC of the region in which they are located, even if they have Beneficiaries in other regions. In other words, an ISGS shall interact with the host RLDC only. For allocations to Beneficiaries in other regions, the host RLDC shall interact with the concerned RLDC, as per modalities worked out between them. The concerned RLDC shall in turn interact with the SLDC of the respective Beneficiary, and then revert to the host RLDC.
2. Scheduling procedure for Talcher-II STPS is described separately. Chukha HEP and Kurichhu HEP in Bhutan shall be scheduled through ERLDC.
3. Each RLDC shall estimate and apportion transmission losses of its own region, for the purpose of determining the drawal schedules of the Beneficiaries and inter-regional schedules with a resolution of 0.1 MW.

### **7.4 SCHEDULING/SETTING AND OPERATION OF TALCHER-II STPS/TALCHER-KOLAR HVDC:**

1. 4x500 MW Talcher-II STPS, though located in Orissa in Eastern region, is fully assigned to the Beneficiaries in Southern region. Also, it is synchronized with the Eastern region and operates at the Central (WR-ER-NER) frequency. Power is transmitted to the Southern region, primarily through the 2x 1000 MW, +/- 500 kV Talcher-Kolar HVDC link, built as a part of the associated transmission system of Talcher-II. It is thus a special case which requires specific stipulations in this grid code.
2. For a clear demarcation of responsibilities and minimal to-and-fro coordination, the scheduling of Talcher-II shall be coordinated by SRLDC, and the 400 kV AC bus-couplers between Talcher-I (2x500 MW) and Talcher-II (4x500 MW) shall be treated as the interface between ER and SR.
3. Talcher-II STPS shall advise the SRLDC (with copies to ERLDC and Talcher HVDC terminal) the ex-power plant MW and MWh capabilities for the next day, by 9 AM every day. The SRLDC shall then interact with the SLDCs of SR, and convey the dispatch schedule of Talcher-II for the next day to Talcher-II STPS, with copies to ERLDC and Talcher HVDC terminal, by 5 PM.
4. Any changes in foreseen power plant capability and in Beneficiaries' requisitions shall be coordinated by SRLDC, and final dispatch and drawal schedules for the next day shall be issued by SRLDC by 11 PM. Any

bilateral exchanges of Talcher-II (for unrequisioned capability, if any) shall also be included in the schedules issued by SRLDC.

5. The base MW level for Talcher-Kolar HVDC link at Talcher end shall be separately advised by SRLDC to Talcher HVDC terminal. It need not be equal to the Talcher-II dispatch schedule, since power can flow to SR via other routes as well, i.e., Gazuwaka HVDC and Chandrapur HVDC. (The HVDC settings are to be optimized by SRLDC).
6. The actual net injection of Talcher-II STPS shall be as metered on 400 kV side of generator transformers of Talcher-II units. The difference between the above actual injection and the dispatch schedule shall constitute the UI of Talcher-II, for which payments shall be made from/into the UI pool account of Southern region operated by SRLDC, but at the UI rate corresponding to ER repeat ER frequency. The energy accounting for Talcher-II STPS shall be carried out by SRLDC.
7. While the dispatch schedule for Talcher-II shall be as advised by SRLDC, the actual generation at Talcher-II may be varied by station operators depending on ER frequency, as long as the resulting UI does not cause a transmission constraint in ER. In case of a transmission constraint being caused in ER by the UI of Talcher-II, ERLDC may advise Talcher-II to curtail its UI under intimation to SRLDC. Any such advise shall be immediately complied with by Talcher-II.
8. CEA, ERLDC, SRLDC, NTPC and Powergrid shall jointly work out and implement the required inter-tripping/runback arrangements between Talcher-II STPS and Talcher-Kolar HVDC link. In particular, the arrangements shall aim at keeping within permissible limits the frequency rise and line overloading in ER and WR in the event of tripping of one or both poles of the HVDC link.
9. In the event of tripping of a Talcher-II unit, the power flow on Talcher-Kolar HVDC link shall not be ramped down as long as ER frequency is higher than the SR frequency. Only when ER frequency is tending to fall below the SR frequency, shall the power flow on Talcher-Kolar HVDC link be ramped down, but gradually and only to the extent necessary to keep the ER frequency just above the SR frequency. However, in case the ER frequency was already below the SR frequency, or has fallen below 49.0 Hz, HVDC power shall be ramped down to the extent of generation loss at Talcher-II without any delay, to save the ER grid from any harmful impact of tripping of the Talcher-II unit.

#### **7.5 DEMARCATION OF SCHEDULING AND HVDC SETTING RESPONSIBILITIES:**

1. NRLDC shall schedule the interchanges of NR with all other regions, and also advise the power settings to Vindhyachal and Sasaram HVDC

stations. The total scheduled import of power from ER/NER into NR may presently be restricted to 500 MW (the capacity of Sasaram HVDC).

2. The SRLDC shall schedule the interchanges of SR with all other regions, and also advise the power settings to Talcher, Chandrapur and Gazuwaka HVDC stations.
3. While specifying the above interchange schedules and HVDC settings, NRLDC and SRLDC shall ascertain (in coordination with ERLDC/WRLDC) that no transmission overloading would be caused on either side of the HVDC links.
4. The settings of HVDC links may not match with the respective inter-regional schedules. Specifically, unscheduled interchange (UI) may be allowed from the system with a higher frequency to the system with a lower frequency, by setting the HVDC links at power levels differing from the respective inter-regional schedules.
5. While specifying the settings of HVDC links under their jurisdiction, NRLDC and SRLDC shall also see whether a diversion of some power from one link to another would reduce transmission losses and/or transmission loading (thereby permitting more inter-regional power transfer), and improve the overall system security/voltage profile.
6. As a general guideline, whenever NR frequency is higher than Central (WR-ER-NER) frequency by more than about 0.2 Hz, the NR→WR power flow through Vindhyachal HVDC shall be maximized. If such frequency differential persists, the ER→NR power flow through Sasaram HVDC shall also be reduced, to the extent possible without overloading ER→WR links.
7. When NR frequency is lower than Central frequency by more than about 0.2 Hz, ER→NR power flow through Sasaram HVDC shall first be maximized. If such frequency differential persists, WR→NR power flow through Vindhyachal HVDC shall be increased, to the extent possible without overloading ER→WR links and the transmission lines in NR.
8. Similarly, when SR frequency is higher than the Central (WR-ER-NER) frequency by more than about 0.2 Hz, the SR→WR power flow through Chandrapur HVDC shall be maximized. If such frequency differential persists, ER→SR power flow through Gazuwaka and Talcher-Kolar HVDC may be reduced to the extent possible without overloading ER→WR links.
9. When SR frequency is lower than Central frequency by more than about 0.2 Hz, ER→SR power flow through Talcher-Kolar and Gazuwaka HVDC shall be maximized. If such frequency differential persists, WR→SR power flow through Chandrapur HVDC shall be increased, to the extent possible without overloading ER→WR links.

10. The WRLDC shall schedule the interchange of power of WR with ER and NER, presently limiting the scheduled import to 1000 MW (thus keeping a security margin of about 500 MW) on ER-WR links. It shall also monitor the power flow on ER-WR ties, and in the event of overloading may request NRLDC/SRLDC to divert some ER-WR power flow through their respective regions. If the required assistance is not forthcoming or is not possible, WRLDC shall order any necessary preventive action in its own region.
11. It is expected that in the normal course, with all major transmission elements available, there would be no transmission constraints between NER and ER, and between ER and SR. If any constraints do arise, the RLDCs shall coordinate between themselves, and with NLDC if necessary, to remedy the situation.

## **7.6 INTERFACES FOR SCHEDULING AND UI ACCOUNTING:**

1. The regional boundaries for scheduling, metering and UI accounting of inter-regional exchanges shall be as follows:
  - a) NR-WR : 400 kV West bus of Vindhyachal HVDC
  - b) WR-SR : 400 kV West bus of Chandrapur HVDC
  - c) NR-ER : 400 kV East bus of Sasaram HVDC
  - d) ER-SR : 400 kV Bus couplers between Talcher-I and Talcher-II  
400 kV East bus of Gazuwaka HVDC
  - e) ER-WR : Rourkela end of 400 kV D/C Rourkela-Raipur line  
Budhipadhar end of 220 kV Budhipadar-Korba Lines
  - f) ER-NER : Bongaigaon end of the 400 kV D/C Malda-Purnea/Binaguri-Bongaigaon line  
Salakati end of 220 kV D/C Birpara-Salakati line
2. The NR-WR and WR-SR exchanges of UI shall be at the UI rate in WR. All other UI exchanges shall be at the UI rate in ER. Payments for inter-regional UI exchanges shall be between the respective regional UI pool accounts, region-to-region.
3. No attempt shall be made to split the inter-regional schedules into link-wise schedules (where two regions have two or more interconnections).

## CHAPTER – 8

### MANAGEMENT OF INDIAN ELECTRICITY GRID CODE

- 8.1 The Indian Electricity Grid Code (IEGC) shall be specified by the Central Electricity Regulatory Commission (CERC) as per section 79 (1) (h) of the Electricity Act, 2003. Any amendments to IEGC shall also be specified by CERC only.
- 8.2 The IEGC and its amendments shall be finalized and notified adopting the prescribed procedure followed for regulations issued by CERC.
- 8.3 The requests for amendments to / modifications in the IEGC and for removal of difficulties shall be addressed to Secretary, CERC, for periodic consideration, consultation and disposal.
- 8.4 Any dispute or query regarding interpretation of IEGC may be addressed to Secretary, CERC and clarification issued by the CERC shall be taken as final and binding on all concerned.
- 8.5 The State Electricity Regulatory Commissions (SERC) shall specify the Grid Codes for operation of the respective intra-State system as per section 86 (1) (h) of Electricity Act, 2003, ensuring that they are consistent with the IEGC.

## **BACKGROUND NOTE**

1. The Central Electricity Regulatory Commission (CERC) had asked the Central Transmission Utility (CTU) i.e. the Power Grid Corporation of India (PGCI) in March 1999 to prepare the draft Indian Electricity Grid Code (IEGC), as per certain directives issued by CERC. In response, PGCI had submitted a draft IEGC dated 08.04.1999, which was then made available through PGCI offices to all those interested in perusing and commenting on the same. A public notice was also issued in newspapers inviting objections on the above draft IEGC by 25.05.1999.
2. The comments and objections received from all parties who responded were discussed in the hearings held by CERC in July 1999, and after further interaction between CERC and PGCIL, the first IEGC was issued in January 2000. There was a review of the IEGC in early 2002 and the first revision as per CERC's order dated 22.02.2002 was issued by PGCIL in March, 2002.
3. Some of the provisions in the current IEGC dated 14.03.2002 require a revision to get aligned with the provisions in the Electricity Act, 2003, which has come into force from 10.06.2003. An important provision under section 79(1) (h) in the new Act is that CERC has "to specify Grid Code having regard to Grid Standards." This implies that the new IEGC has to be a CERC document, rather than a document owned by CTU (and only approved by CERC). As per directive 4 of CERC on 31.03.1999, the CTU had to, in consultation with all utilities, prepare, implement, periodically review and revise and comply with the IEGC. This position has now substantially changed.
4. As per Section 73(d) of the Act, the "Grid Standards for operation and maintenance of transmission lines" are to be specified by Central Electricity Authority (CEA). As and when Grid Standards are specified by CEA, if required, the IEGC shall be amended.

5. The present IEGC has a chapter titled “Management of Indian Electricity Grid Code”, which was relevant in the previous scenario. It provided for an IEGC Review Panel, with Director (Operation), PGCIL as its chairman and convenor. Any change in IEGC required agreement in the IEGC Review Panel and approval by CERC. Now that the responsibility for specifying the Grid code directly vests in CERC, and the Grid Code and its revisions are to be issued adopting the procedure followed for CERC’s regulations, the IEGC Review Panel is no longer necessary. The current exercise of preparing the new draft IEGC is also not being routed through the present IEGC Review Panel, for the same reasons. The above chapter has been rewritten, removing all references to the IEGC Review Panel.
6. As per section 28 (3) (c) of the Electricity Act, 2003, the Regional Load Despatch Centres (RLDC) shall “keep accounts of quantity of electricity transmitted through the regional grid”. Accordingly, the responsibility of preparation of Regional Energy Accounts hitherto with the REB Secretariats, shall stand transferred to the respective RLDCs with effect from 01.04.2006.
7. The Regional Electricity Boards (REB) have been replaced in the new Act by Regional Power Committees (RPC). The Central Government vide its principal resolution dated 25.05.2005 have notified establishment of RPCs. The IEGC has been revised accordingly.
8. Reorganization of the State Electricity Boards (SEBs) envisaged in Part XIII of the Electricity Act, 2003 would lead to formation of a large number of independent entities (generating companies, transmission licensees and distribution licensees) in each State, and consequently a very large number of such intra-State entities in each region. All these entities would come under the regulatory jurisdiction of the concerned State Electricity Regulatory Commission (SERC), and the operational jurisdiction of the concerned State Load Despatch Centre (SLDC). While they would also be connecting into and be synchronized with the same A.C. interconnection,



- i.e., the regional grid, their operation shall be governed by the State Electricity Grid Code specified by the concerned S.E.R.C. Even the directions issued to them by the Regional Load Despatch Centre (the apex body to ensure integrated operation of the regional power system) have to be routed through the concerned SLDC, as per section 29 (3) of the Act.
9. As a logical extension of the above approach and to ensure clear chain of accountability, the following is proposed: (1) The RLDC shall interact and coordinate only with the SLDCs (and the STUs if necessary) on all matters concerning a State, and with no other intra-State entity. (2) The SLDCs shall be responsible for all related coordination with the intra-State entities, and interacting on their behalf with the RLDC. (3) Each State as a whole shall be treated as an entity in the regional grid, and as one entity for the purpose of allocations/shares in Inter-State Generating Station (ISGS), for daily scheduling and despatch, for accounting of unscheduled interchange (UI) and reactive energy. (4) The bifurcation of the State's total entitlement in ISGS availability for the day, advising the intra-State entities about their respective entitlements, and collecting their requisitions, compiling them into State's total requisition from ISGS, etc shall be carried out by the SLDC. (5) The STU/SLDC shall be responsible for installation of special energy meters on the interconnecting points of all intra-State entities who need to have such meters, for organizing the periodic collection of meter readings, preparation of intra-State energy accounts and issuing the UI statements for all concerned entities (.once a week).
  10. This revised IEGC shall be effective from 1<sup>st</sup> April 2006.
  11. The earlier IEGC was silent regarding the payment for reactive energy exchanges directly between the States on State-owned transmission lines. This aspect is now being covered in the revised IEGC under a new section (6.6.7).

12. The intra-State scheme for pricing of reactive energy exchanges between the intra-State entities has to be very carefully deliberated upon by the concerned SERC/STU, and duly covered in the State Electricity Grid Code. The requirements of local reactive support may differ from State to State and the approach may differ from that in this IEGC. For example, the inter-State generating stations (ISGS) have to generate/absorb reactive power as per instructions of RLDC, “without sacrificing on the active generation required at that time”, and “no payment shall be made to the generating companies for such VAR generation/absorption”. This is because (1) the ISGS are mostly located away from load-centres, (2) they generally have a lower variable cost, and (3) they are paid a capacity charge covering the cost of entire installation, including their reactive power capability. The situation of intra-State stations may differ in these respects, and a different approach to their reactive energy output may be necessary.
  
13. When the first version of IEGC was drafted in 1999, inter-regional exchanges were minimal. Many new inter-regional links have since been commissioned and substantial amounts of energy is now being exchanged between the regional grids. A new chapter is being added in the IEGC accordingly, to cover various aspects of scheduling, control and commercial issues of inter-regional exchanges.