THE PUNJAB STATE ELECTRICITY REGULATORY COMMISSION

CHANDIGARH

Notification

The 9th March, 2006

No.PSERC/Secy./Regu. 26 –In exercise of the powers conferred by section 86(1)(h) and 181(1) of the Electricity Act 2003 (Central Act 36 of 2003) and all other powers enabling it in this behalf, the Punjab State Electricity Regulatory Commission hereby makes the following Regulations:-

a. These Regulations may be called the Punjab State Grid Code-2006.

b. These Regulations shall come into force with effect from April 1,2006.

c. These Regulations shall extend to the whole of the State of Punjab.

BY ORDER OF THE COMMISSION

(Ajanta Dayalan)
Secretary to the Commission

PART WISE STATE GRID CODE CONTENTS

SECTION WISE STATE GRID CODE CONTENTS

LIST OF APPENDICES

PART I - GENERAL CODE

STATE GRID CODE – REVISION SHEET

REVISION NUMBER	DATE ISSUED	SECTION (S) REVISED	BRIEF STATEMENT OF CHANGE

SECTION 1 - GENERAL

1.1 Introduction

In compliance with section 86 (1) (h) of the Electricity Act, 2003 the Punjab State Electricity Regulatory Commission hereby specifies the State Grid Code that is consistent with the Indian Electricity Grid Code specified by the Central Electricity Regulatory Commission under section 79 (1) (h) of the Act.

The State Grid Code lays down the rules, guidelines and standards to be followed by all Users of the State Grid to operate and maintain an efficient and coordinated power system in the State in integration with the Northern Regional Grid as per the provisions of Indian Electricity Grid Code (IEGC). The State Grid Code further lays down what is technically optimal with respect to operation and defines standards and common terms to reduce ambiguity and avoid discrimination.

The State Load Despatch Centre (SLDC) shall 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 Grid Standards and the State Grid Code.

1.2 Objectives

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

- To provide clarity and certainty to the STU, State Genco, IPPs/CPPs within Punjab, Distribution Licensees/Discoms and any Open Access Consumers by stating their respective roles, responsibilities and obligations with respect to the operation of the State Transmission System.
- To improve the grid stability and set minimum standards of system performance.
- To define requirement for new entrants i.e. future new generating companies, licensees, CPPs and consumers.
- To document the common knowledge or normal practice in writing for ease of reference and help in compliance.
- To lay down in consultation with generators, performance characteristics of generating plants.
- To improve co-operation by providing a mechanism for clear and consistent disclosure of all information.
- To provide a level playing field.
- To indicate how generation is to be scheduled and despatched.
- To actually enforce what is verbally agreed.

1.3 Structure

The State Grid Code comprises of following parts:

I. General Code

General Code includes sections on:

- Management: intended to ensure that all other sections of the State Grid Code work together in the management of the State Grid Code
- Review Procedures: specify a procedure for review of State Grid Code to cater to inadvertent omissions and any modifications needed from time to time.

II. Planning Code

Planning Code includes sections on:

- System Planning: specifies the procedures to be applied by STU in the planning and development of the State Transmission System and by other Users connected or seeking Connection to the State Transmission System.
- Procedures: specify procedures to be followed by STU in the development of the State Transmission System in the long term taking into account the requirements for new connection of generation and demand.
- Connection Issues: specifies the technical requirements and standards to be complied with by STU and other Users connected or seeking Connection to the State Transmission System.

III. Load Despatch & System Operation Code

Load Despatch & System Operation Code includes sections on:

- System Operation: Specifies the conditions under which STU shall operate the State Transmission System, the Generating Companies shall operate their Power Stations and the Distribution Licensees shall operate their Distribution Systems in so far as necessary to protect the security and quality of supply and safe operation of the State Transmission System under both normal and abnormal operating conditions.

- Schedule and Despatch: Specifies the procedures relating to the scheduling and despatch of Generating Units and drawal by Discoms/ Open Access Customers to meet state demand and drawal allocation.

- Outage Planning: Specifies the procedures relating to the co-ordination of outages for scheduled maintenance of the State Transmission System, Generating Units, CPP and Distribution System that will use the State Transmission System.

IV. Protection Code

Protection Code specifies the co-ordination responsibility and minimum standards of protection that are required to be installed by Users of the State Transmission System.

V. Metering Code

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

VI. Data Registration

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

1.4 Scope

1. State Grid Code defines the boundary between STU and Users and establishes the procedures for operation of facilities connected to the State Grid.

2. All Users that connect with and/or utilize the State Grid are required to abide by the principles and procedures as laid down in the State Grid Code in so far as they apply to that User.

3. The State Grid Code shall be complied with by STU in its capacity as holder of the Transmission Licence and by State Generating Station (SGS), Distribution Licensee, Open Access Consumers and non-licensee (like EHV consumers) connected with STU's transmission system, in the course of generation, transmission, supply and utilisation of electricity.

4. The State Grid Code shall come into effect from April 1, 2006.

1.5 Interpretation

The meaning of certain terms used in the State Grid Code shall be in accordance with the definitions listed in Section 2, "Definitions", of the State Grid Code. Section 2 of this Code has been developed on the premise that accepted engineering terms do not require additional definitions.

The term "State Grid Code" means any or all parts of this document.

1.6 Punjab State Grid

1. Punjab State Power System operates in synchronism with Northern Regional Grid. Northern Regional Grid System consists of power systems of constituent States and Union Territory namely Haryana, Punjab, Rajasthan, Uttar Pradesh, Uttranchal, Himachal Pradesh, Delhi, Jammu & Kashmir and Chandigarh, Railways, Inter-State Generating Stations of National Thermal Power Corporation (NTPC), National Hydro Power Corporation (NHPC), Nuclear Power Corporation (NPC), Bhakra Beas Management Board (BBMB), Satluj Jal Vidyut Nigam (SJVNL), Tehri Hydro Development Corporation Limited (THDCL) and Inter-State Transmission System of Power Grid Corporation of India Limited (PGCIL) and transmission system of BBMB.

2. Punjab Grid have generating stations of Punjab State Electricity Board (PSEB)/State Genco, Captive Power Stations and partnership projects located within state and connected to State Transmission System or

transmission system of BBMB, the distribution network of Discoms connected to State Transmission System at various inter-connection points on 66 KV, 33 KV and 11 KV.

3. The latest position of installed capacity of Generating Stations, details of 400KV, 220 KV, 132 KV transmission lines and list of EHV Sub-stations in the State of Punjab are shown on web-site of PSEB www.psebindia.org and can be downloaded by interested Users.

4. 400 KV Grid Diagram of Northern Region and Single line Grid Diagram of Punjab are shown in NRLDC web-site www.nrldc.org and can be downloaded by the Users. The latest position of allocation of capacity to Punjab in ISGS and BBMB generating stations is shown on web site of NRPC and interested Users may download the same from web site.

1.7 Implementation and Operation of the State Grid Code

1. The date of commencement of this code shall be April 1, 2006. The concerned Utilities/Users shall commence its implementation accordingly.

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

3. The existing connections and equipment shall continue to operate till such time the State Grid Code Review Committee considers alterations necessary. However, operational aspects of the State Grid Code shall have no such relaxation and shall apply with immediate effect.

4. The State Grid Code shall apply to Users, STU and any future transmission licensee. The STU has the responsibility of implementing the State Grid Code.

5. All Users are required to comply with State Grid Code, which shall be enforced by STU. Users must provide STU reasonable rights of access; service and facilities necessary to discharge its responsibilities in the Users premises and to comply with instructions as issued by STU reasonably required to implement and enforce the State Grid Code.

6. SLDC shall not unduly discriminate against or unduly prefer any one or any group of persons; or STU in the conduct of any business other than the Transmission Business.

7. If any User fails to comply with any provision of the State Grid Code, the User shall inform State Grid Code Review Committee without delay the reason for its non-compliance and shall remedy its non-compliance promptly.

8. Consistent failure to comply with the State Grid Code provisions may lead to disconnection of the User’s plant and /or facilities.

9. The operation of the State Grid Code will be reviewed regularly by the State Grid Code Review Committee in accordance with the provisions of the relevant section of the State Grid Code.

1.8 General Requirements

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

2. Users must therefore understand and accept that STU in such unforeseen circumstances may be required to act decisively to discharge its obligations under its Licence. SGS and Discoms shall provide such reasonable co-operation and assistance as STU may decide in such circumstances.

1.9 Code Responsibilities

1. In discharging its duties under the State Grid Code, STU has to rely on information which Users shall supply regarding their requirements and intentions.

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

1.10 Confidentiality

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

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

1.11 Dispute Settlement Procedures

1. In the event of any dispute regarding interpretation of any part/section of the State Grid Code provision between any User and STU, the matter may be referred to the Commission for its decision. The Commission's decision shall be final and binding.

2. In the event of any conflict between any provision of the State Grid Code and any contract or agreement between STU and Users, the provision(s) of the State Grid Code will prevail.

1.12 Communication between STU and Users

1. All communications between STU and Users shall be in accordance with the provision of the relevant section of the State Grid Code and shall be made to the designated nodal officer appointed by STU.

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

3. In case of oral communication the voice shall be recorded at SLDC and such record shall be preserved for a reasonable time to be decided by the State Grid Code Review Committee.

1.13 Directive

State Government may issue policy directives in certain matters as per the Electricity Act 2003. STU shall promptly inform the Commission and all Users of the requirement of such directives.

1.14 Compatibility with Indian Electricity Grid Code

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

1.15 The Board functioning as integrated Utility

The functions of STU, SLDC, Genco and Discoms shall be performed by the concerned officers authorised by the Board as long as it continues to function as an integrated Utility.

SECTION 2 - DEFINITIONS

Defined Term	Definition

Act	The Electricity Act 2003 (Central Act No. 36 of 2003)
Active Energy	Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, and being the integral of the instantaneous power with respect to time, measured in units of watt hours or standard multiples thereof. Unless otherwise qualified, the term “energy” refers to active energy.
Active Power	Active Power means the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof.
Apparatus	Electrical apparatus and includes all machines, fittings, accessories and appliances in which conductors are used.
Apparent Energy	Apparent Energy means the integral of the Apparent Power with respect to time. It is measured in Volt Ampere hour and standard multiple thereof.
Apparent Power	Apparent Power means the product of the root-mean-square (RMS) or effective value of the current and the root-mean-square value of the voltage. For AC circuits or systems, it is the square root of the sum of the squares of the active and reactive power and is measured in kilo volt-ampere (kVA) or multiples thereof.
Appendix	An Appendix to a Section of the State Grid Code.
Area of Supply	As defined in the concerned Licence.
Automatic Voltage Regulator or AVR	A continuously acting automatic excitation system to control the voltage of a Generating Unit as measured at the Generator Terminals.
Backing Down	SLDC instructions or NRLDC instructions conveyed through SLDC for reduction of generation from generating unit under abnormal conditions such as high frequency, low system demand or network constraints.
Base Computer System (BCS)	BCS means Base Computer System meant to handle the data downloaded from meters through CMRI or through remote communication network, converts downloaded raw data into standard output format (e.g. ASCII, CSV) and processes data for various calculations, analysis and display
BBMB	Bhakra Beas Management Board
Black Start Procedure	The process of recovery from a total or partial blackout of the State Transmission System.
Board	The Board refers to Punjab State Electricity Board (PSEB).
Breakdown	An occurrence relating to equipment of supply system which prevents its normal functioning
CBIP	Central Board of Irrigation & Power
Captive Power Plant (CPP)	For the purpose of State Grid Code, the Power Station that meets the criteria laid out in Section 3 of the Electricity Rules, 2005 (framed under Section 176 of the Act).
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
Central Transmission Utility (CTU)	The utility notified by the Government of India under sub-section (1) of Section 38 of the Act.
Common Meter Reading Instrument (CMRI)	CMRI means a common meter reading instrument with necessary accessories capable of downloading data/information from various makes of AC static energy meters when loaded with the corresponding meter specific downloading software(s) called meter reading instrument program(s). (Note: The CMRI can extract information about energy data, load survey data, billing parameters, meter status, meter anomaly and tamper data from the memory of the meter and store for retrieval at a later stage.)
Connection	The electric lines and electrical equipment used to effect a Connection of a User’s (other than STU) system to the State Transmission System.
Connection Agreement	An agreement between STU and a User setting out the terms relating to the Connection to and/or use of the State Transmission System.
Connection Conditions	The technical conditions to be complied with by any User having a Connection to the State Transmission System as laid down in SECTION 5 “Connection Conditions” of the State Grid Code.

Consumer	Any person who is supplied with electricity for his own use by a licensee or the Government or by any other person engaged in the business of supplying electricity to the public under the Act or any other law for the time being in force and includes any person whose premises are for the time being connected for the purpose of receiving electricity with the works of a licensee, the Government or such other person, as the case may be and shall include a person whose electricity supply has been disconnected.
Demand	The demand of active power MW and reactive power MVAR of electricity unless otherwise stated.
Designated Officer	A person identified as having responsibility for inter User safety under SECTION 13 of the State Grid Code.
Despatch Instruction	An instruction by SLDC to SGS (other than CPP) to despatch generation and to Discom to regulate drawal in accordance with the Scheduling & Despatch procedure of State Grid Code.
Disconnection	The act of physically separating a User's or EHV Consumer's electrical equipment from the State Transmission System.
Distribution Entity/Discoms	Discom or Distribution Entity shall mean an entity engaged primarily in the business of distribution & supply of electricity in its area of supply as per the Act including deemed licensee.
Distribution System	The system of wires and associated facilities between the delivery points on the transmission lines or the generating station connection and the point of connection to the installation of the consumers.
Drawal	The import from, or export to, Northern Region, of electrical energy and power or both active/ reactive power. In respect of a Discom, drawal means import from or export to STU of electrical energy and power or both active/reactive.
External Interconnection	Electric lines and electrical equipment used for the transmission of electricity between the State Transmission System and the Regional Transmission System and other states' systems.
Extra High Voltage (EHV)	Nominal voltage levels of 66 kV and above.
EHV Consumer	A person to whom electricity is provided and who has a dedicated supply at 66kV or above voltage.
Forced Outage	An Outage of a SGS or any of Power Station Equipment, generally due to sudden failure of one or more parts of equipment at a generating station, of which no notice can be given by the Generator to STU and also include outage of transmission line and any substation equipment of which no notice can be given by STU or transmission licensee to Discom or vice versa.
Generating Company	A 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 and includes PSEB and its successor generation entity.
Generator	A person or agency who generates electricity and who is subjected to State Grid Code either pursuant to any agreement with STU or otherwise and include SGS, ISGS or inter-state generation/transmission/trading company.
Generating Unit	The combination of an alternator and a turbine set (whether steam, gas, liquid fuel, water or wind driven) or a reciprocating engine and all of its associated equipment, which together represents a single electricity generating machine.
Grid	Grid means the high voltage backbone system of inter-connected transmission lines, sub-stations and generating plants.
Grid Contingencies	Abnormal operating conditions brought out by tripping of generating units, transmission lines, transformers or abrupt load changes or by a combination of the above leading to abnormal voltage and/or frequency excursions and/or overloading of network equipment.
Grid Disturbance	Grid Disturbance is the situation where disintegration and collapse of grid either in

	part or full take place in an unplanned and abrupt manner, affecting the power supply in a large area of the region.
IE Rules	Indian Electricity Rules 1956.
IED	Intelligent Electronic Device
Independent Power Producer (IPP)	Independent Power Producer means a Power Station within the State, owned by a Generator who is not part of PSEB, State Genco, STU, BBMB or Central Sector Generation and is not classified as a CPP.
Indian Electricity Grid Code (IEGC)	A document describing the philosophy and the responsibilities for planning and operation of Indian power system approved by CERC.
Inter Connecting Transformer (ICT)	Transformer connecting EHV system of different voltage levels.
Inter-State Generating Station (ISGS)	A generating station in which two or more than two states have a share and whose scheduling is to be coordinated by the NRLDC.
Inter-State Transmission System (ISTS)	Includes - (i) any system for conveyance of electricity by means of a main transmission line from territory of one state to another state and includes; (ii) the conveyance of electricity across the territory of an intervening state as well as conveyance within the state, which is incidental to such inter-state transmission of energy; (iii) the transmission of electricity within the territory of a state on a system built, owned, operated and maintained by the CTU or by any agency/person under supervision and control of CTU.
Licensee	Licensee means a person who has been granted a Licence under section 14 of the Act including a deemed licensee and shall interalia also include PSEB or its successor entities.
Load Crash	Sudden or rapid reduction of electrical load connected to a system that could be caused due to tripping of major transmission line(s), feeder(s), power transformer(s) or natural causes like rain etc.
Load Survey Data	Load survey data is a database of load values defined in terms of Watt, VAr or VA (or multiples of thereof) during each predefined interval of time
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.
Merit Order Operation	Priority order of various generating units under BBMB/ ISGS/ SGS, operating in synchronism with Northern Grid System, compiled by SLDC pursuant to schedule and despatch requirements, generally in ascending order of variable cost of energy.
Meter	Meter means a device for measurement of bi-directional active energy, reactive energy, apparent energy, active power, reactive power (lag/lead), apparent power, currents, voltages, power factor, frequency and any other electrical parameter derived out of these measurements. Meter shall be capable to record the various parameters as may be required for a particular category of the consumers on the basis of tariff applicable from time to time.
Metering Point	Metering point means the physical location of current and voltage sensing devices (i.e. CTs, VTs) and meters at which electricity is metered.
Metering System	Metering System means set of meters, measurement transformers (CTs & VTs), metering protection equipment including alarms, circuitry and their associated data collection outstations and wiring which are part of the measuring equipment at or relating to a site.
NHPC	National Hydroelectric Power Corporation Limited.
Northern Region / Region	Region comprising of the States and Union Territory of J & K, Punjab, Himachal Pradesh, Haryana, Chandigarh, Uttaranchal, Uttar Pradesh, Rajasthan and Delhi.
Northern Regional Grid System	Northern Regional Grid System means power systems of SEBs/ Utilities/ IPP/ CPPs/Open Access Customers of the States of the Northern Region and of BBMB, NTPC, NHPC, NPC, SJVNL, THDCL & PGCIL having integrated operation.

NPC	Nuclear Power Corporation of India Limited.
NRPC	Northern Regional Power Committee established in accordance with Section 2 (55) of the Act.
NRLDC	Northern Regional Load Despatch Centre.
NTPC	National Thermal Power Corporation Limited.
Open Access	The non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Commission
Open Access Consumer	Open Access Consumer means a consumer who is eligible to receive supply of electricity from a person other than the distribution licensee of his area of supply
Open Access Customer	Open Access Customer means a consumer permitted by the Commission to receive supply of electricity from a person other than distribution licensee of his area of supply, and the expression includes a generating company or a licensee, who has availed of or intends to avail of open access
Outage	In relation to a Generator/ Transmission/ Distribution facility, an interruption of power supply whether manually or by protective relays in connection with the repair or maintenance of the SGS/Transmission facility or resulting from a breakdown or failure of the Transmission /Distribution facility/SGS unit or defect in its Auxiliary system.
Peak Period	That period in a day during which power demand is at its highest.
Planned Outage	An Outage in relation to a SGS unit for Power Station Equipment or Transmission facility which has been planned and agreed with SLDC, in advance in respect of the year in which it is to be taken.
Power Station	An installation of one or more Generating Units (even when sited separately) owned and/or operated by the same SGS and which may reasonably be considered as being managed as a single integrated generating complex.
Power Grid/ PGCIL	The Power Grid Corporation of India Limited.
Protocol	Protocol is the software implemented to exchange the information with external device or equipment through interfacing communication port.
PSERC / Commission	PSERC/Commission refers to Punjab State Electricity Regulatory Commission functioning under section 82 of the Act.
PTW (Permit to Work)	Safety documentation issued to any person to allow work to commence on inter-user boundary after satisfying that all the necessary safety precautions have been established.
Reactive Energy	Reactive Energy means the integral of the Reactive Power with respect to time. It is measured in volt-amperes reactive hours and standard multiples thereof.
Reactive Power	Reactive Power means the product of voltage and current and the sine of the phase angle between them measured in units of volt amperes reactive and standard multiples thereof.
Regional Transmission System	The combination of EHV electric lines and electrical equipment owned or operated by Power Grid / BBMB/ utilities.
Remote Transmitting Unit (RTU)	RTU means a unit for data transmission in digital and sequential mode i.e. to transmit low level analogue / digital signals from transducers, switches, relays etc. connected to it and to transmit received signal to devices connected to it
Rotational Load Shedding	Planned Disconnection of customers on a rotational basis during periods when there is a significant short fall of power required to meet the total demand.
Section	A section or part of this State Grid Code, which is, identified as covering a specific topic.
Simultaneous Maximum Demand	For a given demand period, sum of individual demands across all interface points in a Distribution System gives simultaneous demand of a Distribution Licensee for a given period. SMD means the maximum demand value out of all such simultaneous demands for a month (i.e. maximum demand value out of 4 x 24 x 30 = 2880 periods

	in a 30 day month for demand period of 15 minutes)
Shut Down	The condition of a Generating Unit where it is at rest or on barring gear isolated from Grid or Transmission facility, which is at rest or isolated from Grid.
SJVNLvSatluj Jal Vidyut Nigam Limited	
Spinning Reserve	Unloaded generating capacity, which is synchronised to the System and is ready to provide increased generation at short notice pursuant to despatch Instruction or instantaneously in response to frequency drop.
State	The State of Punjab.
State Genco	A Generating Company, which owns or operates or maintains the State owned Generating Stations within the State of Punjab and includes PSEB and its successor generation entity.
State Grid Code / Grid Code/ Code	The State Grid Code specified under clause (h) of sub-section (1) of section 86 of the Electricity Act 2003.
State Grid Code Review Committee/Committee	The Committee set up under SECTION 3 “Management of State Grid Code” of State Grid Code.
State Load Despatch Centre (SLDC)	The State Load Despatch Centre means the centre established under sub-section (1) of section 31 of the Act and having its control room at Ablowal (Patiala).
Sub Area Load Despatch Centre (SALDC)	These are Sub Area Load Despatch Centres set up at Lalto Kalan (near Ludhiana) and Jamsher (near Jalandhar) linked to SLDC at Patiala.
State Generating Station (SGS)	Any power station whether State owned or private except the Inter-State Generating Station (ISGS) and located within the State.
State Transmission System (STS)	The intra state system of EHV electric lines and electrical equipment operated and/or maintained by STU or any Transmission Licensee for the purpose of the transmission of electricity between Generating Stations, external interconnections, distribution system and any other User connected to it.
State Transmission Utility (STU)	The Board or Government Company specified as such by the Government of Punjab under sub-section (1) of section 39 of the Electricity Act, 2003.
Supervisory Control and Data Acquisition (SCADA)	The combination of transducers, RTU, communication links and data processing systems, which provides information to the SLDC on the operational state of the State Transmission System.
Synchronised	The condition where an incoming Generating Unit or System is connected to another System so that the voltage, frequencies and phase relationships of that Generating Unit or System, as the case may be, and the System to which it is connected are identical and the terms “Synchronise” and “Synchronisation” shall be construed accordingly.
THDCL	Tehri Hydro Development Corporation Limited
Transmission Licence / Licence	The Licence to be granted by the Commission under section 14 of Electricity Act 2003.
Unscheduled Generation	The difference between the actual generation and the scheduled generation.
User	A person, including any successor entity of PSEB, Generating Stations within Punjab, Transmission Licensees or Distribution Licensees within Punjab and Open Access Customers who use the State Transmission System and who must comply with the provisions of the State Grid Code.

Note: 1. Terms defined in singular shall be construed to apply for plural also.

2 Words and expressions used and not defined in this Code but defined in the Act shall have the meanings assigned to them in the Act. Subject to the above, expressions used herein but not specifically defined in this Code or in the Act shall have the meaning as is generally assigned in the electricity industry.

SECTION 3 MANAGEMENT OF THE STATE GRID CODE

3.1 Introduction

1. STU is required to implement and comply with the State Grid Code and periodically review the same and its implementation. For the above purpose a State Grid Code Review Committee, as per section 3.4, shall be established.

2. Subject to the conditions in the next paragraph of this section, all revisions in the State Grid Code shall be made by consensus in the meeting of State Grid Code Review Committee with majority of members voting. In the event of no consensus being reached, the matter shall be referred to the Commission for decision. All revisions in the State Grid Code shall be approved by the Commission.

3. In any unusual situation where normal day-to-day operation is not possible without revision of some section (s) of the State Grid Code, a provisional revision may be implemented before approval of the Commission is received, but only after discussions at a special meeting of State Grid Code Review Committee convened on emergency basis. The Commission shall be intimated at the earliest but not later than 15 days about the provisional revision by recorded means of communication.

4. The changes/revisions proposed by the State Grid Code Review Committee shall be consistent/ compatible with IEGC.

5. The Commission may issue directives requiring STU to revise, supplement or replace the State Grid Code in such manner as may be specified in those directives and STU shall forthwith comply with any such directives.

6. This document defines the procedure to be followed by STU in managing the State Grid Code and also in pursuing any change.

3.2 Objective

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

3.3 Responsibilities

1. STU shall be responsible for managing and servicing the State Grid Code.

2. STU shall establish and service the requirements of the State Grid Code Review Committee in accordance with provisions of section 3.5 of the State Grid Code.

3. All users of the Grid shall be responsible to comply with the provisions of the State Grid Code.

3.4 State Grid Code Review Committee

1. STU shall inform all Users of the names and addresses of the Committee Chairman and Member Secretary within 15 days of the approval of the State Grid Code, and shall inform Users in writing of any subsequent changes.

   NRPC, NRLDC, BBMB shall inform the Committee Member Secretary of the name and designation of their representative within 30 days of the approval of State Grid Code by PSERC and shall inform the Committee Member Secretary, in writing, of any subsequent change.

2. The State Grid Code Review Committee shall be chaired by the Managing Director, STU and consist of the following members:
   - Managing Director of STU - Chairman
   - Chief Engineer level officer of STU - Member Secretary
   - Managing Director of State Genco - Member
   - Managing Director(s) of Discoms – Member(s)
   - SE (In-charge SLDC) - Member

- One member representing transmission and distribution licensee (other than STU/ Discoms) - Member
- One representative of IPP/CPP – Member
- Further, one representative each from BBMB, NRPC and NRLDC may participate in the Committee as a special invitee.
  A member may nominate his alternative for one or more meetings.

3.5 State Grid Code Review Committee Proceedings

1. The Rules to be followed by the Committee in conducting their business shall be formulated by the Committee itself and approved by the Commission. The Committee shall meet at least once in three months. The functions of the State Grid Code Review Committee shall be as follows:
   - To keep the State Grid Code and its implementation under scrutiny and review.
   - To propose any revision, if necessary, in the State Grid Code consequent to analysis report on major grid disturbance soon after its occurrence. The recommendations of the Committee shall be submitted to the Commission for approval and issue of directives to the Users for taking necessary remedial measures, as may be deemed fit, to prevent recurrence.
   - To consider all requests for amendment to the State Grid Code as may be made by the Users.
   - To issue guidance on the interpretation and implementation of the State Grid Code.
   - To examine problems raised by the Users.
2. Sub-meetings may be held by STU with a User to discuss individual requirements and with groups of Users to prepare proposals for the Committee meeting. The Committee may set up sub committees for detailed studies of related problems.

3.6 State Grid Code Review and Revisions

1. STU shall, in consultation with Users and NRPC and such other persons as the Commission may direct, every three years, or earlier if required by the Commission, review the State Grid Code and its implementation.
2. The Commission shall reserve the right to review the State Grid Code as and when required.
3. The Member Secretary shall present all proposals for revisions of the State Grid Code to the Committee for its consideration.
4. STU shall send to the Commission following reports at the conclusion of each review meeting of the Committee.
   i. A report on the outcome of such review;
   ii. Any proposed revisions to the State Grid Code from time to time as STU thinks reasonably necessary for the achievement of the objectives of the State Grid Code alongwith justification therefor.
5. All revisions to the State Grid Code shall require the prior written approval of the Commission.
6. STU shall convey to all concerned, revisions to the State Grid Code after approval by the Commission and the same shall be incorporated in the subsequent version of the State Grid Code.
7. The revision number and date of issue shall appear on every page of the State Grid Code. Every change from the previous version shall be clearly marked in the margin. In addition, a revision sheet shall be placed at the front along with the General Code that lists the number of every changed section, together with a brief statement of change.
8. STU shall make available a copy (other than service copy) of the respective parts of the State Grid Code in force for sale to any person requesting for it.
9. STU shall keep an up-to-date list of the recipients and locations of all authenticated copies of the State Grid

Code.

10. SLDC shall put the latest State Grid Code with list of amendments on its web-site.

3.7 Functional Committees

1. STU is responsible for servicing/implementation of the State Grid Code whereas the State Grid Code Review Committee shall be responsible for management of the State Grid Code for any changes, modifications therein. The State Grid Code Review Committee shall constitute following functional committees for implementation of the State Grid Code:
   - Planning Code: Transmission Planning Committee (TPC)
   - System Operation Code: Operation and Co-ordination Committee (OCC)
   - Protection Code: Protection Co-ordination Committee (PCC)
   - Energy Accounting & Metering: Commercial & Metering Committee (CMC)

2. The State Grid Code Review Committee shall nominate the members of the functional committees. Chairman and Member Secretary of the functional committees shall be from STU.

   However, the State Grid Code Review Committee can formulate any other operational committee as it deems fit for the implementation of the State Grid Code.

3. Transmission Planning Committee (TPC)

   Transmission Planning Committee shall coordinate the implementation of Planning Code (Part II) to ensure system planning coordination for the state as a whole.

   TPC shall comprise of Chief Engineer level members to be nominated by the State Grid Code Review Committee, which shall meet once every three months and deliberate on all technical and operational aspects of Planning Code and shall give their recommendations to the State Grid Code Review Committee.

   The rules to be followed by the committee in conducting their business shall be formulated by the committee itself and shall be approved by the State Grid Code Review Committee.

   The committee shall perform the following functions:
   i. Co-ordination of system planning, execution of works, maintenance schedule and contingency plan to ensure adequate transmission and distribution system

   ii. Review of existing interconnection equipment for alteration, if necessary, so as to comply with the Connection Conditions provided for in the State Grid Code.

   iii. Review the load forecast and the methodology and assumptions made by Users.

   iv. Review and finalise the proposals identified on the basis of planning studies.

4. Operation and Co-ordination Committee (OCC)

   Operation and Co-ordination Committee shall coordinate the implementation of Load Despatch & System Operation Code (Part III) to ensure that respective Generators and Distribution Companies using State Transmission System discharge their obligations under the State Grid Code.

   OCC shall comprise of Chief Engineer level members to be nominated by the State Grid Code Review Committee, which shall meet every month and deliberate on all technical and operational aspects of Load Despatch and System Operation and shall give their recommendations to the State Grid Code Review Committee.

   The rules to be followed by the committee in conducting its business shall be formulated by the committee itself and shall be approved by the State Grid Code Review Committee.

   The committee shall perform the following functions:
   i. Review the reactive compensation in the State Transmission System.

ii. Review the load shedding mechanisms.
iii. Review and analyse the grid disturbances and system restoration procedure
iv. Finalisation, review and amendment of Outage Plan of State Transmission System
v. Deliberate and prepare the Under Frequency Load Shedding Schemes and the mechanism to be adopted for the same for various sub-stations to ensure that the frequent tripping of same feeder is avoided.
vi. Review the installation of Disturbance Recorders, Event Loggers in the State Transmission System.

5. Protection Co-ordination Committee (PCC) Protection Co-ordination Committee shall coordinate the implementation of Protection Code (Part IV) to ensure that respective Users using State Transmission System discharge their obligations under the Protection Code.

   Protection Co-ordination Committee shall comprise of Chief Engineer level members to be nominated by the State Grid Code Review Committee, which shall meet once every three months and shall give their recommendations to the State Grid Code Review Committee.

   The rules to be followed by the Protection Co-ordination Committee in conducting its business shall be formulated by the committee itself and shall be approved by State Grid Code Review Committee. The committee shall perform the following functions.
   i. Keep Protection Code and its implementation under scrutiny & review and to ensure compliance thereof;
   ii. Consider all requests for amendment to the Protection Code which any User makes;
   iii. Create awareness about various issues related to the Protection Code.
   iv. Deliberate and decide various protection settings, testing procedure and periodicity.
   v. Review and specify the minimum protection requirements for the User's system connected to the State Transmission System.
   vi. Deliberate and decide regarding upgradation of protection schemes and necessary switchgear equipments.
   vii. Review and analyse the failure of protection system in case of major grid disturbance and recommend modifications and improvements.

6. Commercial & Metering Committee Commercial & Metering Committee (CMC) shall coordinate the implementation of the Metering Code (Part V) to ensure that the respective constituents discharge their obligations under the Metering Code. The committee shall also be responsible for coordinating the preparation of state energy account in accordance with the provisions of the State Grid Code.

   The committee shall comprise of Chief Engineer level members to be nominated by the State Grid Code Review Committee, which shall meet every month.

   The rules to be followed by the Commercial & Metering Committee in conducting its business shall be formulated by the committee itself and shall be approved by the State Grid Code Review Committee.

   The committee shall perform the following functions.
   i. Keep Metering Code and its implementation under scrutiny and review and to ensure compliance thereof.
   ii. Consider all requests for amendment to the Metering Code which any User makes.
   iii. Create awareness about various issues related to the Metering Code.
   iv. Review deviations in the existing CTs and PTs/CVTs from the minimum specifications prescribed in the State Grid Code and upgradation/ replacement of the same within one year of coming into effect of the State Grid Code.
   v. Deliberate and decide the issues relating to the monthly energy account and settlement prepared by SLDC.
   vi. Resolve any energy accounting and settlement disputes arising out of metering failure.
   vii. Review and amend, if necessary, the methodology and principles for maintaining State Energy Accounts.

3.8 Non-Compliance & Derogation

1. If any User fails to comply with any of the provision(s) of the State Grid Code, the User shall inform STU without delay of the reason for its non-compliance and shall remedy its non-compliance promptly.

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

3. Consistent failure to comply with the State Grid Code may lead to disconnection of the User's plant and/or facilities.

4. Derogation, if any, for any particular section or chapter of the State Grid Code shall be with the express permission of the Commission for a specified time. Derogation of any requirement of the State Grid Code shall be exception and not the norm, and will be allowed only when it is impossible and not just difficult or inconvenient for the User to comply with in the required time-scale. Failure to comply with fixed-time derogation by any User shall carry a financial penalty as shall be decided by the Commission while allowing derogation.

3.9 Power to Remove Difficulties

1. If any difficulty arises in giving effect to any provisions of the Code, the Commission may by general or special order, direct the State Transmission Utility, State Load Despatch Centre, Generators, CPPs, Licensees and the Open Access Customers, to take such action as may appear to the Commission to be necessary or expedient for the purpose of removing difficulties.

PART II - PLANNING CODE

SECTION 4 SYSTEM PLANNING

4.1 Introduction

1. This section specifies the methods for data submissions by Users to STU for the planning and development of the State Transmission System. This section also specifies the procedure to be applied by STU in the planning and development of the State Transmission System.

2. A requirement for reinforcement or extension of the State Transmission System may arise for a number of reasons, including but not limited to the following:
   i. Development on a User's system already connected to the State Transmission System.
   ii. The introduction of a new Connection point between the User's system and the State Transmission System.
   iii. Evacuation system for Generating Stations within or outside the State.
   iv. Reactive Compensation.
   v. A general increase in system capacity due to addition of generation or system load.
   vi. Transient or steady state stability considerations.
   vii. Cumulative effect of any of the above.

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

STU, and Users, having regard where appropriate, to the confidentiality of such information.

4.2 Objective

The provisions of this section are intended to enable STU to produce a plan in consultation with Users, to provide an efficient, coordinated, secure and economical State Transmission System to satisfy requirement of future demand. The Planning Code:

- Defines the procedure for the exchange of information between STU and a User in respect of any proposed User development on the User's system, which may have an impact on the performance of the User.

- Details the information which STU shall make available to Users in order to facilitate the identification and evaluation of opportunities for use of or connection to the State Transmission System;

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

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

4.3 Planning Policy

1. STU would develop a perspective transmission plan for next 15 years for the State Transmission System. These perspective transmission plans shall be updated every year to take care of the revisions in load projections and generation capacity additions. The perspective plans shall be submitted to the Commission for approval.

2. STU shall carry out annual planning process corresponding to a 5 year forward term for identification of major State Transmission System schemes which shall be dovetailed into National Electricity Plan on 5 years short term basis and 15 years long term perspective plan prepared by CEA.

3. STU shall carry out network studies and review fault levels for planning system strengthening and augmentation.

4. STU shall follow the following steps in planning:
   i. Forecast the demand for power within the Area of Supply, based on the forecasts provided by Discoms, and provide to the Commission details of the demand forecasts, data, methodology and assumptions on which the forecasts are based. These forecasts would be annually reviewed and updated.
   ii. Prepare a proposal for the requirement of generation for the State to meet the load demand as per the forecast, after examining the economic; technical and environmental aspects of all available alternatives taking into account the existing contracted generation resources and effects of demand side management.

   iii. Prepare a transmission plan for the State Transmission System compatible with the above load forecast and generation plan. This will include provision for VAR compensation needed in the State Transmission System.

   iv. The reactive power planning exercise to be carried out by STU in consultation with NRLDC/NRPC, Discoms, as per the Commission's directives and Programme for installation of reactive compensation equipment by STU & Discoms.

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

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

vii. STU would maintain a historical database based on operational data supplied by SLDC using the state-of-the-art tools such as Energy Management System (EMS) for demand forecasting.

viii. STU shall be responsible to prepare and submit a long-term plan for the period upto 2012 to the Commission for generation expansion and transmission system expansion to fully meet both energy and peak demand for the period upto 2012 and create adequate reserve capacity margin.

ix. The STU would coordinate with the CTU for eliminating transmission constraints in a cost effective manner.

5. All the Users shall supply to STU, the planning data prescribed in Appendix A and Appendix B of Data Registration Code within 3 months from the effective date of the State Grid Code and thereafter such data shall be furnished by 31st March every year to enable STU to formulate and finalise the updated plan by 30th September each year for the next 5 years.

4.4 Planning Standards and Security Criteria

1. The State Transmission System planning and generation expansion planning shall be in accordance with the provisions of the planning criterion as per IEGC Clause 3.5. However, some planning parameters of the State Transmission System may vary according to directives of the Commission.

2. The planning criterion shall be based on the security philosophy on which both ISTS and the State Transmission System have been planned. The security philosophy shall be as per the Transmission Planning Criteria and other CEA guidelines.

4.5 Planning Responsibility

1. The primary responsibility of load forecasting within Discom's Area of Supply rests with respective Distribution Entities. The Distribution Entities shall determine peak load and energy forecasts of their areas for each category of loads for each of the succeeding 5 years and submit the same annually by 31st March to STU along with details of the demand forecasts, data, methodology and assumptions on which the forecasts are based along with their proposals for transmission system augmentation. The load forecasts shall be made for each of the prevalent as well as proposed interconnection points between STU and Discoms and shall include annual peak load and energy projections. The demand forecasts shall be updated annually or whenever major changes are made in the existing forecasts or planning. While indicating requirements of single consumers with large demands (1 MW or higher) the Distribution Entity shall satisfy itself as to the degree of certai! nty of the demand materialising.

2. SGS shall provide their generation capacity to STU for evacuating power from their power stations for each of the succeeding 5 years along with their proposals for transmission system augmentation and submit the same annually by 31st March to STU.

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

4. Transmission Planning Committee consisting of members from each Discom, STU and State Genco shall review and approve the load forecasts and the methodology followed by each of the Discoms.

5. The State Transmission System proposals identified based on planning studies would be discussed, reviewed and finalised by the Transmission Planning Committee.

4.6 Planning Data

1. To enable STU to conduct System Studies and prepare perspective plans for electricity demand, generation and transmission, the Users shall furnish data, to STU from time to time as detailed under Data Registration section as under:
   a. Standard Planning Data (Generation)/ Standard Planning Data (Distribution) as per APPENDIX A

   b. Detailed Planning Data (Generation)/ Detailed Planning Data (Distribution) as per APPENDIX B.

2. To enable the Users to co-ordinate planning design and operation of their plants and systems with the State Transmission System, they may seek certain salient data of Transmission System as applicable to them, which STU shall supply from time to time as detailed under Data Registration section and categorized as:
   a. Standard Planning Data (Transmission) as per APPENDIX A.
   b. Detailed Planning Data (Transmission) as per APPENDIX B.

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

SECTION 5 CONNECTION CONDITIONS

5.1 Introduction

Connection Conditions specify the technical, design and operational criteria which must be complied with by every User connected to the State Transmission System.

5.2 Objective

The objective of this section is to ensure the following:

i. All Users or prospective Users are treated equitably.

ii. Any new Connection does/shall not impose any adverse effect on existing Users nor shall a new Connection suffer adversely due to existing Users.

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

iv. The ownership and responsibility for all items of equipment is clearly specified in a schedule (Site Responsibility Schedule) for every site where a Connection is made.

5.3 Procedure for Application

The procedure for any new connection or modification of an existing connection with the State Transmission System shall consist of following:

i. The User shall submit the application to STU containing all the information as may be specified.

ii. STU shall make a formal offer within 60 days of the receipt of the application. The offer shall specify and take into account any works required for the extension or reinforcement of the State Transmission System necessitated by the applicant’s proposal and for obtaining any consent necessary for the purpose.

iii. If the specified time limit for making the offer against any application is not adequate, STU shall make a preliminary offer within the specified time indicating the extent of further time required for detailed analysis.

iv. Any offer made by STU shall remain valid for a period of 60 days and unless accepted before the expiry of such period, shall lapse thereafter.

v. In the event of offer becoming invalid or not accepted by the applicant, STU shall not be bound to consider any further application from the same applicant within 12 months unless the new application is substantially different from the original application.

vi. The applicant shall furnish the Detailed Planning Data as per APPENDIX-B.

5.4 Rejection of Application

STU shall be entitled to reject any application for connection to or use of the State Transmission System due to the following reasons apart from others as considered reasonable:

i. If such proposed connection is likely to cause breach of any provision of its Licence or any provision of the State Grid Code or any provision of IEGC or any criteria or covenants or deeds or regulations

by which STU is bound.

ii. If the applicant does not undertake to be bound, in so far as applicable, by the terms of the State Grid Code.

iii. If the applicant fails to give confirmation and undertakings according to this section.

5.5 Connection Agreement

A Connection Agreement (or the offer for a Connection Agreement) shall include within its terms and conditions the following:

i. A condition requiring both agencies to comply with the State Grid Code.

ii. Details of connection charges and/or use of system charges.

iii. Details of any capital related payments arising from necessary reinforcement or extension of the system.

iv. Diagram of electrical system to be connected.

v. General philosophy, guidelines etc on protection.

vi. A Site Responsibility Schedule (APPENDIX-D).

5.6 Site Responsibility Schedule

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

i. The ownership of equipment.
ii. The responsibility for control of equipment.

iii. The responsibility for maintenance of equipment.

iv. The responsibility for operation of equipment.

v. The manager of the site.

vi. The responsibility for all matters relating to safety of persons at site.

5.7 System Performance

1. All equipment connected to the State Transmission System shall be of such design and construction that enables STU to meet the requirement of Standards of Performance. Discoms and other users shall ensure that their loads do not cause violation of these standards.

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

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

4. SGS (except CPPs) shall make available to SLDC the up to date capability curves for all Generating Units, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to / Import from the State Transmission System.

The State Transmission System rated frequency shall be 50.00 Hz and shall be regulated by the provisions of IEGC as given below:

Target range		Statutory acceptable limit	
Upper Limit	50.50 Hz	Upper Limit	51.50 Hz
Lower Limit	49.00 Hz	Lower Limit	48.50 Hz

5. The User shall be subject to the Grid discipline prescribed by SLDC/ NRLDC as per guidelines mutually agreed with NRPC/NRLDC.

The variation of voltage at the inter connection point should not be more than the voltage range specified below: **Limits of Voltage Variation**			
Nominal (KV)	% Limit of variation	Maximum (KV)	Minimum (KV)
400	+5%/-10%	420	360
220	+/-10%	245	200
132	+/-10%	145	120
66	+/-10%	72	59

6. Discoms and Open Access Customers shall ensure that their loads do not affect STU system in terms of causing any:
   i. Unbalance in the phase angle and magnitude of voltage at the interconnection point beyond the limits prescribed.

   ii. Total Harmonic Distortion (THD) shall not exceed 1% at the inter-connection point of EHV system determined in accordance with IEEE 519–1992 Recommended Practices and Requirement of Harmonic Control in Electrical Power system.

   STU may direct the Discoms to take appropriate measures to remedy the situation.

7. In the event of Grid disturbances / Grid contingencies in the Northern Regional grid, STU shall not be liable to maintain the system parameters within the normal range of voltage and frequency.

8. Insulation Co-ordination of the User's equipment shall conform to values as specified by STU from time to time out of those applicable as per Indian Standards / Codes. Rupturing capacity of switchgear shall not be less than that specified by STU from time to time.

9. Protection schemes and metering schemes shall be as detailed in the Protection Code and Metering Code.

5.8 Connection Point

1. State Generating Station (SGS)
   Voltage may be 220/132/66 KV or as agreed with STU.

   Unless specifically agreed with STU, the Connection point with generating station shall be the terminal isolator provided just before the outgoing gantry of the feeders.

   SGS shall operate and maintain all terminals, communication and protection equipments provided within the generating station.

   The provisions for the metering between generating station and STU system shall be as per the Metering Code.

   Respective Users shall maintain their equipments from the out going feeders' gantry onwards emanating from generating station,

2. Distribution Company

Voltage may be LV side of power transformer i.e. 66 KV, 33 KV or 11 KV or as agreed with STU. For EHV consumers directly connected to transmission system, voltage may be 220 KV/ 132 KV/ 66 KV.

Unless specifically agreed with Discom, the Connection point with STU shall be the terminal isolator provided just before the outgoing gantry of the feeder to Discom or individual EHV consumer as the case may be, from STU sub-station.

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

3. Northern Regional Transmission System

For the Northern Regional Transmission System, the Connection, protection scheme, metering scheme and the voltage shall be in accordance with the provisions of IEGC.

4. IPPs, CPPs, EHV Consumers and Open Access Customers

Voltage may be 220/132/66 KV or as agreed with STU.

When IPPs, CPPs, EHV Consumers or the Open Access Customers own sub-stations, the Connection point shall be the terminal isolator provided just before the gantry of outgoing/incoming feeder in their premises.

5. Data Requirements

Users shall provide STU with data for this section as specified in SECTION 18.

Unless otherwise agreed in Connection Agreement, the equipments for data transmission and communication shall be operated and maintained by the User in whose premises it is installed irrespective of ownership.

SECTION 6 SYSTEM SECURITY ASPECTS

6.1 Introduction

All Users shall endeavor to operate their respective power system and generating stations in synchronism with each other at all times, so that the whole State Transmission System operates as a synchronised system as well as integrated part of Northern Regional Grid. STU shall endeavor to operate the inter state links so that inter state transfer of power can be achieved smoothly when required. Security of the power system and safety of power equipment shall enjoy priority over economically optimal operations.

6.2 Scope

The system security relates to entire inter-connected power system. The system security aspect therefore affects all Users of the regional inter-connected power systems. However, the operation of the State Transmission System will be controlled and maintained by SLDC in accordance with directions and instructions of NRLDC under provisions of IEGC.

6.3 System Security

1. All switching operations, whether affected manually or automatic, will be based on policy guide lines of:
   - IEGC
   - National Load Despatch Centre/ NRLDC's instructions/Guidelines under IE Rules or Rules framed under the Act.
   - State Grid Code
   - PSERC's directives
   - State Grid Code Review Committee's decisions approved by the Commission

2. No part of the State Transmission System shall be deliberately isolated from the integrated Grid, except
   i. Under an emergency, and conditions in which such isolation would prevent a total Grid collapse

and/or enable early restoration of power supply,

ii. When serious damage to a costly equipment is imminent and such isolation would prevent it,

iii. When such isolation is specifically advised by SLDC,

iv. On operation of under frequency/islanding scheme as approved by NRPC/PSERC and

v. All such isolations shall be either as per standing guidelines approved by NRPC/PSERC or shall be put up in the State Grid Code Review Committee for ratification. Complete synchronisation of integrated Grid shall be restored, as soon as the conditions again permit it. The restoration process shall be supervised by SLDC as per relevant procedures separately finalised.

3. The 66 KV and above transmission lines (except radial lines which do not affect the operation of the Grid) and ICTs shall not be deliberately opened or removed from service at any time except when advised by SLDC or with specific and prior clearance of SLDC. Where prior clearance from SLDC is not possible, it should be intimated to SLDC at the earliest possible time after the incident. Any emergency tripping not advised or permitted by SLDC shall be put up to the State Grid Code Review Committee for ratification in the next meeting.

4. Any tripping, whether manual or automatic, of any of the elements mentioned above, shall be precisely reported to SLDC at the earliest. The reason (to the extent determined) and the likely time of restoration shall also be intimated. All reasonable attempts shall be made for the elementary restoration at the earliest. The information/ data including that downloaded from disturbance recorder, sequential event logger outputs etc. containing the sequence of tripping and restoration shall be sent to SLDC for the purpose of analysis.

5. 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 is required to be operated without its governor in normal operation, the NRLDC through SLDC shall be immediately advised about the reason and duration of such operation. The exemption from free governor mode operation in respect of run of river hydro stations without any pondage, steam turbine of thermal and gas based power stations not having free governor mode facility shall be sought from CERC under clause 1.6 of IEGC. Such petitions for exemption shall be preceded by a study preferably by CEA.

6. Facilities available with/in Load Limiters, Automatic Turbine Run-up System (ATRS), Turbine Supervisory Coordinated Control system etc. shall not be used to bypass the normal governor action in any manner. No dead bands and time delays shall be deliberately introduced.

7. 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 for at least five (5) minutes or within technical limits prescribed by the manufacturer 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. Any generating unit of over fifty (50) MW size not complying with the above requirement shall be kept in operation (synchronised with the Regional grid) only after obtaining the permission of NRLDC through SLDC. However, the 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. Any generating unit not capable ! of complying with above provisions either due to not having requisite facilities or otherwise shall seek exemption from CERC under clause 1.6 of IEGC.

8. In case frequency falls below 49.5 Hz, all partly loaded Generating Units shall pick up additional load at a faster rate, according to their capability. SLDC in consultation with NRPC/NRLDC and Discoms shall prepare a plan for automatic load relief during the low frequency conditions. In case frequency rises to 50.5 Hz or higher, neither any generating unit shall be synchronized with the Grid nor shall generation at any generating station (irrespective of type or ownership) be increased without obtaining approval from SLDC.

9. Except under an emergency, or to prevent an imminent damage to costly equipment, no User shall suddenly decrease/increase its generation without prior intimation to the SLDC. Similarly, no User shall cause a sudden decrease/increase in its load due to imposition/lifting of power cuts etc., without prior intimation to and consent of SLDC, particularly when frequency is deteriorating.

10. 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 capacity is required to be operated without its AVR in service, the same should be operated only after prior concurrence of SLDC.

11. Each Generating Unit must 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.

12. SGS and other generating stations connected to the Grid shall follow the instructions of SLDC for backing down/boxing up (ramping-down) and shutting down the generating unit(s). SLDC shall provide the certificate for the period of the backing down/boxing up or shutting down for the purpose of computing the deemed generation, if required.

13. Provision of protections and relay settings shall be coordinated by the Protection Co-ordination Committee in the State Transmission System as per plan to be separately finalized by the Committee.

14. Various steps shall be taken for frequency management (as per Section 9.3) and voltage management (as per Section 9.5) so as to ensure system security from these considerations.

15. All Generating Units with capacity of 200 MW and above and important 220 KV sub-stations with transformation capacity above 250 MVA shall be provided with the facilities of Disturbance Recorders (DRs) and Event Loggers (ELs) with GPS time synchronization. STU shall submit time-bound plan to install DRs wherever it is required as per this Code. Such Disturbance Recorders (DRs) and Event Loggers (ELs) may be either independent stand-alone type or provided with numeric relays provided at these sub-stations.

PART III - LOAD DESPATCH & SYSTEM OPERATION CODE

SECTION 7 OPERATIONAL PLANNING

7.1 Introduction

This section describes the process by which the SLDC carries out the operational planning and demand control procedures to permit reduction in Demand for any reason.

7.2 Objective

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

7.3 Demand Estimation

1. The long-term demand estimation/ load forecast (for more than 1 year) shall be done by the planning department of STU in accordance with the provisions of SECTION 4. SLDC shall be provided with a copy of the same as and when it is finalised. Demand Estimation for period up to 1 year ahead shall be done by SLDC.

2. Distribution Licensees/ Discoms shall provide to the SLDC their estimates of demand for the year ahead on monthly-basis at each inter connection point for the next financial year by 15th November each year. Distribution Licensees/ Discoms shall also provide daily demand for the month ahead at each inter connection point by 25th for the next month.

3. Distribution Licensees/Discoms shall provide to SLDC on day ahead basis at 9.00 hrs each day their

estimated demand for each 15-minute block for the ensuing day along with the estimates of load that may be shed when required, in discrete blocks with the details of arrangements of such load shedding.

4. The SLDC would update the demand forecast (in MW as well as MWh) on quarterly, monthly, weekly and ultimately on daily basis, which would be used in the day-ahead scheduling. Attention shall also be paid by SLDC in demand forecasting for special days such as important festivals, religious occasions and National Holidays having different crests and troughs in the daily load-curve as compared to normal weather conditions & days.

5. SLDC shall furnish data for and participate in deliberations on data for load generation balance or Annual Demand, availability and shunt capacitors requirement studies of NRPC. It shall take into consideration their reports for demand estimation.

7.4 Demand Control

1. Primarily the need for demand control would arise on account of the following conditions:
   - Lariations in demand from the estimated or forecasted values, which cannot be absorbed by the grid, and
   - Unforeseen generation/transmission outages resulting in reduced power availability, and
   - Heavy reactive power demand causing low voltages, and

2. SLDC shall match the consolidated demands of the Distribution Licensees/ Discoms with consolidated generation availability from SGS, ISGS, IPP/CPP and other sources and exercise the Demand Control to ensure that there is a balance between the energy availability and the Distribution Licensees/Discoms demand plus losses plus the required reserve.

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

4. SLDC shall advise STU for planning of Automatic load shedding schemes and Rotational Load Shedding through installation of Under Frequency Relays.

5. The guidelines for under frequency load shedding shall be prepared, in accordance with the instructions from NRLDC/NRPC, by the Operation and Co-ordination Committee and shall be approved by the State Grid Code Review Committee.

6. Rotational Load Shedding Schemes using Under Frequency Relay (UFR) shall be prepared time to time by the Operation and Coordination Committee in accordance with the guidelines/instructions issued by NRLDC/NRPC and these schemes shall be duly approved by the State Grid Code Review Committee.

7. The particulars of feeders or group of feeders at a STU sub-station which shall be tripped under under-frequency load shedding scheme whether manually or automatic on rotational basis or otherwise shall be displayed on Notice Board and will also available at the sub-station for information of the consumer(s).

8. Demand control can also be exercised by SLDC through direct circuit breaker tripping affected from SLDC using RTUs and under frequency detection by SCADA or through telephonic instructions. No demand shed by operation of under frequency relays shall be restored without specific directions from SLDC.

7.5 Load Crash

1. In the event of load crash in the system due to weather disturbance or any other reasons, the situation would be controlled by SLDC by the following methods in descending priorities:
   i. Lifting of the load restrictions, if any
   ii. Exporting the power to neighbouring regions/ states
   iii. Backing down of thermal stations with a time lag of 5-10 minutes for short period in merit order.

iv. Closing down of hydel units (subject to non spilling of water and effect on irrigation) keeping in view the inflow of water into canals and safety of canals/hydel channels.

The above methodology shall be reviewed from time to time in Operation and Co-ordination Committee.

2. While implementing the above, the system security aspects should not be violated as per provisions in section 5.2 of IEGC and Section 6 of the State Grid Code. Further, in case of hydro generation linked with irrigation requirements, the actual backing down or closing down of such hydro units shall be subject to limitations on such account & to avoid spillage of water.

7.6 Demand Control by Distribution Licensee/Discom

Distribution Licensee/Discom shall provide SCADA and data management systems in their area of control for efficient working of Distribution Systems. The Distribution Licensee/Discom shall prepare and send SCADA and data management system report to SLDC. Distribution Licensee/Discom shall provide sub-station automation equipment within one year from date of coming into effect of the State Grid Code.

SECTION 8 SCHEDULE AND DESPATCH

8.1 Introduction

This section specifies the procedure to be adopted for the scheduling and despatch of SGS, ISGS and power plants under BBMB to meet system demand and Drawal allocation requirements of Discoms.

8.2 Objective

The objective of this section is to detail the actions and responsibilities of SLDC in preparing and issuing a daily schedule of generation and the responsibilities of Users to supply the necessary data and to comply with that schedule.

8.3 General

1. The following specific points would be taken into consideration while preparing and finalising the schedules:

SLDC will issue despatch instructions required to regulate all generation and imports from IPPs / CPPs according to the 15-minute day ahead generation schedule, unless rescheduling is required due to unforeseen circumstances.

In the absence of any despatch instruction by SLDC, SGS shall generate/ export according to the day- ahead generation schedule.

However the SLDC shall regulate the overall state generation in such a manner that generation from following types of power stations where energy potential, if unutilized, goes waste shall not be curtailed:

- Run of river or canal based hydro stations.
- Storage type hydro-stations like those of BBMB when water level is at peak reservoir level or expected to touch peak reservoir level as per inflows.
- Nuclear power stations to avoid poisoning of fuel.

Despatch instructions to SGS shall be in standard format to be finalized by SLDC. These instructions will recognize declared availability and other parameters that have been made available by the SGS to SLDC. These instructions shall include time, Power Station, Generating Units, (Total export in case of CPP), name of operators sending and receiving the same. Standard despatch instructions may include:

- To switch a SGS into or out of Service.
- Details of reserve to be carried on a unit.
- To increase or decrease MVAr generation to assist with voltage profile as per unit capability at that time
- To begin pre-planned Black Start procedures.
- To hold spinning reserve.
- To hold Generating Units of SGS on standby.
- To control MW/MVAr Drawal by Distribution Entities.

8.4 Generation Scheduling

1. Steps in Scheduling

Step by step procedure for scheduling of ISGS, BBMB generating stations and SGS/IPP/CPP shall be as described below:

i. By 9.00 hrs every day each SGS shall intimate to SLDC the station wise ex- power plant MW and MWh capabilities foreseen for the next day i.e. between 00.00 to 24.00 hrs of the following day, at 15 minutes interval.

ii. By 9.00 hours every day each Discom shall intimate SLDC the overall requirement in MW and MWh for the next day at 15 minutes interval.

iii. The generation scheduling for the stations under Bhakra Beas Management Board (BBMB) would be coordinated and finalized before 10.00 hrs by BBMB in accordance with the requirements of the beneficiary states viz. Punjab, Haryana, Rajasthan and Himachal Pradesh and subject to the irrigation and hydrology constraints. The schedules so finalized for each BBMB station and also generation scheduling of ISGS would be communicated to NRLDC before 10.00 hrs every day by BBMB and respective ISGS as per provisions of IEGC.

iv. These generation schedules of ISGS & BBMB power plants shall be compiled by NRLDC and the MW and MWh entitlements available to Punjab during the following day at 15 minutes intervals shall be intimated by NRLDC to SLDC by 10.00 hrs.

v. After receipt of the information in regard to the availability from different sources at (i), (iii) & (iv) above, the SLDC shall review aggregate demand of generating capability of SGS and the bilateral interchanges, if any, vis-à-vis Discoms requirements.

vi. By 15.00 hrs, SLDC shall finalise (a) generation schedule of SGS and (b) drawal schedule of each Discom. It shall accordingly advise each Discom of their drawal schedule and will workout and convey to NRLDC for net drawal schedule in each of the ISGS along with the bilateral exchanges agreed or intended to be had with the other state / states and the estimates of demand / availability in the state and additional power it would like to draw subject to availability.

vii. By 1700 hrs, NRLDC shall convey to SLDC the drawal schedule for Punjab State from each of the ISGS and BBMB. SLDC shall convey to SGS the generation schedule and drawal schedule to Discoms by 1900 hrs.

viii. SGS and each Discom may inform the modifications / changes to be made, if any, in the above schedule to SLDC by 21.30 hours.

ix. SLDC after considering the same shall convey revised schedule to NRLDC by 22.00 hrs.

x. On receipt of information and after due consultations, the NRLDC shall issue the final generation and drawal schedule by 23.00 hrs, and SLDC shall inform the same to all concerned.

2. SLDC shall prepare the day ahead generation schedule keeping in view the followings:

i. Transmission System constraints from time to time.

ii. 15 minute load requirements as estimated by SLDC.

iii. The need to provide operating margins and reserves required to be maintained.

iv. The availability of generation from SGS and Central Sector Generators together with any constraint in each case.

8.5 Revision in drawal schedule on real time basis

During the day of operation, the drawal schedule may be revised under following conditions:

i. In case of forced outage of a unit of any SGS, SLDC may revise the generation schedule on the basis of revised declared capability by the affected SGS.

ii. NRLDC may revise the schedule of drawal from Northern Region and consequently SLDC shall enforce the revisions within Punjab.

iii. Revision of schedules of SGS shall be governed by IEGC.

8.6 Drawal Scheduling

SLDC is responsible for collection, examination and compilation of drawal Schedule for each Discom in prescribed manner and at the prescribed time. Each Discom shall supply to SLDC 15-minute average demand estimates in MW for the day ahead.

8.7 Generation Despatch

1. SGS shall comply promptly with a despatch instruction issued by SLDC unless this action would compromise the safety of plant or personnel. SGS shall promptly inform SLDC in the event of any unforeseen difficulties in carrying out an instruction.

2. Despatch instructions shall be issued by E-Mail /Fax/ telephone, confirmed by exchange of name of operators sending and receiving the same and logging the same at each end. All such oral instructions shall be complied with forthwith and written confirmation shall be issued promptly by FAX, tele-printer or otherwise

8.8 Data Requirements

Users shall provide SLDC with data for this section as specified in the Data Registration section.

SECTION 9 FREQUENCY & VOLTAGE MANAGEMENT

9.1 Introduction

This section describes the method by which all Users of the State Transmission System shall co-operate with SLDC and STU in contributing towards effective control of the system frequency and managing the voltage of the State Transmission System.

The State Transmission System normally operates in synchronism with the Northern Region Grid and NRLDC has the overall responsibility of the integrated operation of the Northern Regional Power System. The constituents of the Region are required to follow the instructions of NRLDC for backing down generation, regulating loads, MVAR drawal etc. to meet the objective.

SLDC shall accordingly instruct Generating Units to regulate Generation/Export and hold reserves of active and reactive power within their respective declared parameters. SLDC shall also regulate the load as may be necessary to meet the objective.

The State Transmission System voltage levels can be affected by Regional operation. The STU/SLDC shall optimize voltage management by adjusting transformer taps (On Line Tap Changers) to the extent available and switching of circuits/ capacitors/ reactors and other operational steps. SLDC will instruct SGS to regulate MVAr generation within their declared parameters. SLDC shall also instruct Discoms to regulate demand, if necessary.

9.2 Objective

The objectives of this section are as follows:

- To define the responsibilities of all Users in contributing to frequency and voltage management.

- To define the actions required to enable SLDC and STU to maintain the State Transmission System voltages and frequency within acceptable levels in accordance with IEGC guidelines as well as Planning and Security Standards for the State Transmission System specified by the Commission, if any.

9.3 Frequency Management

1. The rated frequency of the system shall be 50 Hz and shall normally be regulated within the limits prescribed in IEGC Clause 4.6(b) as also specified in Connection Conditions. STU & SLDC as constituent of Northern Region shall make all possible efforts to ensure that grid frequency remains within 49.0 – 50.5 Hz band.

2. Falling frequency
   Under falling frequency conditions, SLDC shall take appropriate action to issue instructions, in co-ordination with NRLDC to arrest the falling frequency and restore frequency within permissible range. Such instructions may include despatch instruction to SGS and/or instruction to Discoms and Open Access Customers to reduce load demand by appropriate manual and/or automatic load shedding.

3. Rising Frequency
   Under rising frequency conditions, SLDC shall take appropriate action to issue instructions to SGS in co-ordination with NRLDC to arrest the rising frequency and restore frequency within permissible range. SLDC shall also issue instructions to Discoms and Open Access Customers in coordination with NRLDC to lift Load shedding (if exists) in order to take additional load. In case of Load Crash, SLDC shall take steps as per SECTION 7.5 of the Code.

9.4 Responsibilities

1. SLDC shall monitor actual power drawal against scheduled power drawal and regulate internal generation and demand to maintain this schedule. SLDC shall also monitor reactive power drawal and availability of capacitor banks.

2. Generating Stations within Punjab shall follow the despatch instructions issued by SLDC.

3. Discoms and Open Access Customers shall comply with the instructions of SLDC for managing load & reactive power drawal as per system requirement.

9.5 Voltage Management

1. Users using the State Transmission System shall make all possible efforts to ensure that the grid voltage always remains within the limits specified in IEGC at clause 5.2 (r) and IE Rules 1956 as re-produced below:

Voltage (KV rms)		
Nominal	Maximum	Minimum
400	420	360
220	245	200
132	145	120
66	72	59

2. STU and/or SLDC shall carry out load flow studies based on operational data from time to time to predict where voltage problems may be encountered and to identify appropriate measures to ensure that voltages remain within the defined limits. On the basis of these studies, SLDC shall instruct SGS to maintain specified voltage level at interconnecting points. SLDC and STU shall co-ordinate with the Discoms to determine voltage level at the interconnection points.

   SLDC shall continuously monitor 220/132/66 KV voltage levels at strategic sub-stations.

3. SLDC shall take appropriate measures to control State Transmission System voltages, which may include but not be limited to transformer tap changing, capacitor / reactor switching including capacitor switching by Discoms at 66 KV & 33 KV substations, operation of Hydro unit as synchronous condenser and use of MVAr reserves with SGS within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

4. SGS (except CPPs) shall make available to SLDC the up to date capability curves for all Generating Units, as detailed in SECTION 5, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to / Import from State Transmission System.

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

9.6 General

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

SECTION 10 MONITORING OF GENERATION & DRAWAL

10.1 Introduction

The monitoring of SGS output and active and reactive reserve capacity is important to evaluate the performance of generation plants.

The monitoring of actual Drawal against schedule is important to ensure that STU and Discoms contribute towards improving system performance and observe Grid discipline.

10.2 Objective

The objective of this section is to define the responsibilities of all SGS in the monitoring of Generating Unit reliability and performance, and STU's/ Discoms' compliance with the scheduled Drawal to assist SLDC in managing voltage and frequency.

10.3 Monitoring Procedure

1. For effective operation of the State Transmission System, it is important that a SGS's declared availability is realistic and that any departures are continually and invariably fed back to the Generator to help effect improvement.

2. The SLDC shall continuously monitor Generating Unit outputs and Bus voltages. More stringent monitoring may be performed at any time when there is reason to believe that a SGS's declared availability may not match the actual availability or declared output does not match the actual output.

3. SLDC can ask for putting a generating station to demonstrate the declared availability by instructing the generating station to come up to the declared availability within time specified by generators.

4. SLDC shall inform a SGS, in writing, if the continual monitoring demonstrates an apparent persistent or material mismatch between the despatch instructions and the Generating Unit output or breach of the Connection Conditions. Continued discrepancies shall be resolved by the State Grid Code Review Committee with a view to either improve performance in future, providing more realistic declarations or initiate appropriate actions for any breach of Connectivity Conditions. Continued default by the generating stations entails penalty as may be determined by the Commission.

5. SGS (excluding CPPs) shall provide to SLDC 15-minute block-wise generation summation outputs where no automatically transmitted metering or SCADA/RTU equipment exists. CPPs shall provide to SLDC 15-minute block-wise export / import MW and MVAr.

6. The SGS shall provide any other logged readings that SLDC may reasonably require, for monitoring purposes where SCADA data is not available.

10.4 Generating Unit Trippings

1. SGS shall promptly inform SLDC of the tripping of a Generating Unit, with reasons in accordance with SECTION 14 'Operational Event/Accident Reporting'. SLDC shall intimate NRLDC about the trippings and their revival. SLDC shall keep a written log of all such trippings, including the reasons with a view to demonstrating the effect on system performance and identifying the need for remedial measures.

2. SGS shall submit a more detailed report of Generating Unit tripping to SLDC on monthly basis.

10.5 Monitoring of Drawal

1. SLDC shall continuously monitor actual MW Drawal by Distribution Licensees/ Discoms and other users against their schedules through use of SCADA equipment wherever available, or otherwise using available metering. SLDC shall request NRLDC and adjacent States as appropriate to provide any additional data required to enable this monitoring to be carried out.

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

10.6 Data Requirement

SGS shall submit data to SLDC as listed in Data Registration Section (Appendix C-5).

SECTION 11 OUTAGE PLANNING

11.1 Introduction

This section describes the process by which STU shall carry out the planning of outage in the State Transmission System, including interface co-ordination with Users.

11.2 Objective

The objective of this section is to define the process which will allow STU to optimise transmission Outages with SGS (other than CPP) and Discoms' Outages in co-ordination with outage planning of regional system while maintaining system security to the extent possible.

11.3 Outage Planning Process

1. Each User shall provide their outage programme for ensuing financial year to SLDC for preparing an overall outage plan for the State Transmission System as a whole. SLDC shall be responsible for analyzing the outage schedules of all users including SGS, Discoms, STU and Transmission Licensee(s) schedules for outage of Transmission network and preparing a draft annual Outage Plan for the State Transmission System in coordination with the Outage Plan prepared for the region by NRPC. The Users shall furnish the information to SLDC as per APPENDIX C.

2. However, SLDC is authorised to defer the outage in case of any of the following events:
    - Major grid disturbance
    - System Isolation
    - Black out in the State

- Any other event in the system that may have an adverse impact on system security by the proposed outage

3. Each User shall obtain approval of SLDC, prior to availing the Outage.

   SLDC while releasing any circuit for outage shall issue specific code. Similarly, no inter user boundary circuits shall be connected back to the State Transmission System without specific code/approval by SLDC.

   This restriction shall however not be applicable to individual Generating Unit(s) of a CPP.

11.4 Annual Outage Planning

1. Scheduled outage of power stations of capacity 25 MW & above as notified by SLDC from time to time, will be subject to annual planning.

2. Provided that scheduled outage of power station of 50 MW and above and EHV lines as notified by NRLDC, will also be subject to annual planning by NRLDC in co-ordination with SLDC.

3. SGS (except CPPs) connected to the State Grid shall furnish their proposed Outage programme for the next financial year in writing by 15th November each year.

4. SGS Outage programme shall contain details like identification of unit, reason for outage, generation availability affected due to such outage, outage start date and duration of outage. SLDC shall review the outage programme received from SGS on monthly basis to chalk out the outage of the State Transmission System.

5. SLDC shall also obtain from STU, the proposed outage programme for Transmission lines, equipments and sub-stations etc. for next financial year by 15th November each year. STU outage programme shall contain identification of lines/ substations, reasons for outage, outage start date and duration of outage.

6. Scheduled outage of power stations and EHV transmission lines affecting regional power system shall be affected only with the approval of NRLDC in co-ordination with SLDC.

7. Scheduled outage of power stations of capacity 25 MW and above, of all EHV lines and HV lines forming interconnection between two EHV substations (and these notified as such by SLDC) shall be approved by SLDC, 24 hours in advance based on prevalent operating conditions.

8. In respect of scheduled outage referred in this section a calendar shall be formulated in respect of annual outage planning for the ensuing financial year. Such outage plan shall be deliberated and finalised in the meeting of the Operation and Co-ordination Committee (OCC).

11.5 Availing of shutdowns schedule

1. SLDC would review on daily basis the outage schedule for the next two days and in case of any contingency or conditions described in section 5.7.4(g) of the IEGC, defer any planned outage as deemed fit clearly stating the reasons thereof. The revised dates in such cases would be finalized in consultation with the User.

2. The shutdowns for scheduled outage shall be taken in accordance with the provisions of SECTION 13 of the State Grid Code to ensure inter-user coordination.

SECTION 12 CONTINGENCY PLANNING

12.1 Introduction

This section describes the steps in the recovery process to be followed by all Users in the event of total or partial blackouts of the State Transmission System or Regional System.

12.2 Objective

The objective of this section is to define the responsibilities of all Users to achieve the fastest recovery in the event of the State Transmission System or Regional System blackout, taking into account essential loads, generator capabilities and system constraints.

12.3 Contingency Planning Procedure

SLDC shall be prepared to face and efficiently handle the following types of contingencies and restoration of system back to normal in accordance with the System Restoration Procedure of Northern Region prescribed under IEGC:

- Partial system black out in the state due to multiple tripping of the transmission lines emanating from power stations/sub-stations
- Total black out in the state/region
- Synchronisation of system islands and system split

In case of partial black out in the system/state, priority is to be given for early restoration of power station units, which have tripped. Start up power for the power station shall be extended through shortest possible route and within shortest possible time from adjoining sub-station/power station where the supply is available. Synchronising facility at all power stations and 220 kV sub-station having inter-connection with ISTS shall be available.

In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of NRLDC for early restoration of the entire grid. Start-up power to the thermal stations shall be given by the hydel stations or through interstate supply, if available. All possible efforts shall be made to extend the hydel supply to the thermal power stations through shortest transmission network so as to avoid high voltage problem due to low load conditions. For safe and fast restoration of supply, SLDC shall formulate the proper sequence of operation for major generating units, lines, transformers and load within the state in consultations with NRLDC. The sequence of operation shall include opening, closing/tripping of circuit breakers, isolators, on-load tap-changers etc.

12.4 Restoration Procedure

Punjab falls in North-Central (NC) sub-system of the Northern Regional Grid. SLDC shall follow the sequence prescribed for restoration procedure, avail start-up power and synchronize the system elements as per the directions and instructions prescribed for North-Central (NC) sub-system of latest NR Restoration Procedure. Detailed procedure for restoration of the State Transmission System shall be prepared by SLDC for the following contingencies and shall be in conformity with the System Restoration Procedure of the Northern Region prescribed under IEGC.

-
- Total System Black out
- Partial System Blackout
- Synchronisation of System Islands and System Split

The restoration process shall take into account the generator capabilities and the operational constraints of Regional and the State Transmission System with the object of achieving normalcy in the shortest possible time. All Users should be aware of the steps to be taken during major Grid Disturbance and system restoration process.

12.5 Special Considerations

During restoration process following the State Transmission System orRegional System blackout conditions, normal standards of voltage and frequency shall not apply.

Distribution companies with essential loads shall separately identify non-essential components of such loads, which may be kept off during system contingencies. Distribution Companies shall draw up an appropriate schedule with corresponding load blocks in each case. The non-essential loads can be put on only when system normalcy is restored, as advised by SLDC.

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

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

12.6 Post Disturbance Analysis

SLDC as per guidelines and instructions from NRLDC shall carryout the post disturbance analysis of all major grid disturbances resulting into total or partial system blackout and system split and desynchronism of any part of the State Grid. All users shall co-ordinate and furnish the data pertaining to the system disturbance to enable SLDC to analyse the system disturbance and furnish report to NRLDC in accordance with Section 5.9 of the IEGC.

Protection Coordination Committee shall also review the data collected and analyse the failure of protection system either of STU or any User and recommend modification and / or improvement in the protection system/ relay setting schemes and, if necessary, of the islanding and restoration scheme of Northern Region, to be carried out by the Grid Users.

SECTION 13 INTER USER BOUNDARY SAFETY

13.1 Introduction

This section sets down the requirements for maintaining safe working practices associated with inter user boundary operations. It lays down the procedure to be followed when work is required to be carried out on electrical equipment that is connected to another User's system.

13.2 Objective

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

13.3 Designated Officers

STU and all Users shall nominate suitably authorized persons to be responsible for the co-ordination of safety across that company boundary. These persons shall be referred to as Designated Officer(s).

13.4 Procedure

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

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

3. Whenever work across an inter-user boundary is to be carried, the Designated Officer of the User including STU itself, wishing to carry out work shall personally contact the other relevant Designated Officer. If the Permit to Work (PTW) cannot be obtained personally, the Designated Officers shall contact through telephone and exchange Code words to ensure correct identification of both agencies.

4. Should the work extend over more than one shift, the Designated Officer shall ensure that the relief Designated Officer is fully briefed on the nature of the work and the code words in operation.

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

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

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

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

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

   Any dispute concerning inter user Boundary Safety shall be resolved at the level of Operation & Co-ordination Committee.

13.5 Special Consideration

1. For inter-user boundary between STU and other User's circuits, all Users shall comply with the agreed safety rules, which must be in accordance with IE Rules or Rules framed under the Act.

2. Each Designated Officer shall maintain a legibly written safety log, in chronological order, of all operations and messages relating to safety co-ordination sent and received by him. All safety logs shall be retained for a period of not less than 10 years.

SECTION 14 OPERATIONAL EVENT/ ACCIDENT REPORTING

14.1 Introduction

This section describes the reporting procedure of reportable events in the State Transmission System

14.2 Objective

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

14.3 Reportable Events

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

- Exceptionally high / low system voltage or frequency.
- Serious equipment problem relating to major circuit breaker, transformer or bus bar.
- Loss of major Generating Unit.
  System split, State Transmission System breakaway or Black Start.
- Tripping of Transmission Line, ICT (Inter connecting transformer) and capacitor banks.
- Major fire incidents.
- Force-Majeure condition like flooding or lightening etc.
- Major failure of protection.

- Equipment and Transmission Line overload.
- Accidents-Fatal and Non-Fatal.
- Load Crash / Loss of Load
- Excessive Drawal deviations.
- Minor equipment alarms.

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

14.4 Reporting Procedure

1. Reporting Time for events and accidents

   All reportable incidents occurring on lines and equipment of 66 KV and above and all the lines on which there is the inter user flow affecting the State Transmission System shall promptly be communicated by the User whose equipment has experienced the incident (the reporting User) to any other significantly affected Users and to SLDC.

   Within 1 (one) hour of being informed by the Reporting User, SLDC should ask for a written report on any incident.

   If the reporting incident cannot be classified as minor then the Reporting User shall submit an initial written report within two hours to SLDC. This has to be further followed up by the submission of a comprehensive report within 48 hours of the submission of the initial written report.

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

2. SLDC shall call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been source of the reportable incident.

   The above shall not relieve any User from the obligation to report events in accordance with IE Rules.

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

   i. Location of incident.
   ii. Date and time of incident.
   iii. Plant or equipment involved.
   iv. Details of relay indications with nature of fault implications.
   v. Supplies and quantum interrupted and duration if applicable.
   vi. Amount of generation lost if applicable.
   vii. Brief description of incident.
   viii. Estimate of time to return to service.
   ix. Name of originator.
   x. Possibility of alternate arrangement of supply

14.5 Reporting Form

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

14.6 Major Failure

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

14.7 Accident Reporting

Reporting of accidents shall be in accordance with the section 161 of the Electricity Act, 2003 and the rules framed thereunder. Notice of accident and failure of supplies or transmission of electricity shall be in the specified form to the Commission and the Electrical Inspector.

SECTION 15 ENERGY ACCOUNTING

15.1 Energy Accounting

1. Section 32 (2) (c) of the Act specifies the function of State Load Despatch Centre in the preparation of Energy Account for the quantity of electricity transmitted through the State Grid.

2. SLDC shall prepare every month, the accounts of energy injection and energy drawal by:-:-
   - Distribution Licensees
   - Open Access Customers within Punjab
   - SGS, CPP connected to the State Grid.
   - Injection/drawal through BBMB system and NRPC as reflected in Monthly Regional Energy Account (REA).

3. The monthly state energy accounts so prepared by SLDC shall be sent to all concerned for the purpose of monthly billing.

4. In the preparation of such energy accounts, SLDC shall take into consideration:-
   i. Bulk Supply Agreements for supply and/or transmission of power, bilateral agreements, short term and spot purchases affected by any licensee, and
   ii. Policy guidelines or decisions of State Grid Code Review Committee
   iii. Decisions/directives of the Commission,
   iv. Components of tariff as approved by the Commission, and
   v. Such accounts by BBMB and NRPC.

5. For the purpose of preparation of energy accounts, the joint meter reading(s) taken on 1st of every month at inter connection points between STU and State Genco or any IPP or CPP or Open Access Customers and between STU and Discoms or between two distribution licensees shall be conveyed to SLDC by 5th of every month.

6. Monthly State Energy accounts for Punjab shall be prepared by SLDC by 7th of every month and shall be conveyed to all concerned for raising bills. Such energy accounts shall be subject to inspection/verification/checking and raising any objection within 15 days of date of issue. If no objection is raised, energy accounts shall be finalized. In case, any objection is raised, same shall be deliberated in Commercial and Metering Committee and finalized as per their decision. Supplementary bills/credit note shall be raised accordingly.

7. In case energy accounts prepared/finalized by SLDC require any change on account of revisions of energy accounts by BBMB or NRPC, SLDC shall suo-moto or on the request of Commercial & Metering Committee shall effect changes following the provisions of SECTION 15.1.5 above.

15.2 SLDC Fee and Charges

1. SLDC as per provisions of the section 32 (3) of the Act, may levy SLDC fee and charges from the Generating Companies and Licensees engaged in intra-state transmission of electricity as may be determined by the Commission. SLDC fee & charges shall be levied upon Open Access Customers and CPPs in accordance with Open Access Regulations framed by the Commission.

2. SLDC shall serve to each utility on 7th of every month the bills of its fees and charges. These charges shall be payable by 13th of every month. Delay in payment of SLDC fee and charges shall be subject to levy of late payment surcharge. Besides this, SLDC may direct disconnection of the utility from the Grid or regulate their supply/despatch and may approach competent authority for levy of fines.

PART IV - PROTECTION CODE

SECTION 16 PROTECTION

16.1 Introduction

In order to safeguard the State Transmission System and Users' system from faults occurring in other User's system, it is essential that certain minimum standards for protection be adopted. This section describes these minimum standards.

16.2 Objective

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

16.3 General Principles

1. Protection standards are treated as interface issues because of the possible severe inter-user boundary repercussions of faults that occur in the system of any entity. Minimum protection requirements are prescribed in this section because inadequate protection or mal-operation of protection system of any entity may result in far reaching consequences, disturbances and even damages to the systems of other entities.

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

3. All Users shall co-operate to ensure correct and appropriate settings of protection to achieve effective, discriminatory removal of faulty equipment within the time for target clearance specified in this section.

4. Protection settings shall not be altered, or protection relays bypassed and/or disconnected without consultation and agreement between all affected Users. In a case where protection is bypassed and/or disconnected by an agreement, then the cause must be rectified and the protection restored to normal condition as quickly as possible. If agreement has not been reached, the electrical equipment shall be removed from service forthwith.

5. NRLDC shall advise STU regarding:
   i. Planning for upgrading and strengthening protection system based on analysis of grid disturbance and partial/total blackout in the State Transmission System.

   ii. Planning of Islanding and System Split schemes and installation of Under Frequency Relays and df/dt relays. The Protection Practices and Protocol Manual shall have provision for the same.

6. Protection Co-ordination

   aA Protection Coordination Committee (PCC) shall be constituted as per SECTION 3.7.5 of the State Grid Code and shall be responsible for all the protection coordination functions defined under the same section. STU shall be responsible for arranging periodical meetings of the Protection Coordination Committee. STU shall investigate any malfunctioning of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection mal-function or issue as discussed and agreed to in these periodical meetings. Protection Coordination Committee shall decide the date from which the existing protection provided in STU and/ or User systems not meeting the minimum requirement as stipulated in this code is required to be changed.

16.4 Fault Clearance Times & Short-time Ratings

1. From stability consideration, the minimum short circuit current rating and time and the maximum fault clearance times for faults on any User's system directly connected to the State Transmission System, or any

faults on the State Transmission System itself, are as follows:

Nominal Voltage	Minimum Short Circuit current rating & duration for Switchgear		Target Fault clearance Time
KV	KA(rms)	Seconds	msec.
220 KV	40	1	100
132 KV	40	1	100
66 KV	25	1	160

2. Slower fault clearance times for faults on a Users system may be agreed to but only if, in STU's opinion, system conditions allow this. STU shall specify the required opening time and rupturing capacity of the circuit breakers at various locations for STU and Discoms/Open Access Customers directly connected to Transmission System. At generating stations, line faults should be cleared at the generation station end within the critical clearing time so that the generators remain in synchronism.

16.5 Generator Requirements

All Generating Units and all associated electrical equipment of the Generating Units connected to the State Transmission System shall have adequate protection so that the State Transmission System does not suffer due to any disturbances originating from the Generation units. The generator protection schemes shall cover at least Differential protection, back up protection, Stator & Rotor Earth fault protection, field ground/field failure protection (not applicable to brush-less excitation system), negative sequence protection, under frequency, over flux protection, inter-turn Differential protection for generator, restricted E/F for Generator Transformer, back- up impedance protection, pole slipping protection (applicable to units above 200MW), reverse power protection etc.

16.6 Transmission Line Requirements

1. General

Every EHV line taking off from a Power Station or a sub-station shall have protection and back up protection as mentioned below. STU shall notify Users of any changes in its policy on protection.

Switchgear equipment and Relay Panels for the protection of lines of STU taking off from a Power Station shall be owned and maintained by the Generator. Any transmission line related relay settings or any change in relay settings will be carried out by the Generator in close co-ordination and consultation with STU. All such issues shall be put up in the next meeting of Protection Coordination Committee for ratification. Carrier cabinets / equipment, Line matching units including wave traps and communication cable shall be owned and maintained by STU. All Generators shall provide space, connection facility, and access to STU for such purpose.

2. 220 KV Transmission Lines

All 220 KV transmission lines owned by STU shall have two fast acting protection schemes.

Main 1 protection scheme shall be numeric, three zone, non-switched fast acting distance protection scheme with permissible inter-trip at remote end (in case of zone-2 fault). The scheme shall have power swing blocking, location of fault recording, disturbance recording, event logger, communication port, single and three shot auto reclosing as well as Local Breaker Backup (LBB).

Main 2 protection scheme shall be static/ numeric, three zone, switched/ non-switched fast acting distance protection scheme having all features as main- 1 except auto reclosing & Local Breaker Backup (LBB).

For back-up protection, three directional IDMTL over current relays and unidirectional earth fault relay shall be provided.

3. 132 KV and 66 KV Lines

A single scheme three zone, non-switched numeric distance protection with standard built in features like single and three phase tripping, carrier inter-tripping, IDMT over current and earth fault, power swing blocking and LBB protection shall be provided as main protection.

The backup protection shall be at least two directional IDMTL over current relays and one directional earth fault relay.

For short transmission radial lines, appropriate alternative protection schemes may be adopted.

16.7 Transformer Requirements

1. The protection of EHV Transformers, Power Transformers and Distribution Transformers shall be as per revised manual on transformers published by Central Board of Irrigation and Power (CBIP) Publication No. 275.

   The following minimum protections should be provided for transformers:

   i. All 220 KV class power transformers shall be provided with numeric fast acting differential, REF, open delta (Neutral Displacement Relay) and over-fluxing relays. In addition, there shall be back up IDMTL over current and earth fault protection. For parallel operation, such back up protection shall have inter-tripping of both HV and LV breakers. For protection against heavy short circuits, the over current relays should incorporate a high set instantaneous element. In addition to electrical protection, transformer own protection viz. buchholz, OLTC oil surge, gas operated relays, winding temperature protection, oil temperature protection, PRV relay shall be provided for alarm and trip functions.

   ii. For 132 KV, 66 KV and 33 KV class transformers of capacity 5 MVA and above, the protection shall be same as mentioned in 16.7.1 (i) except over-fluxing, REF and PRV relays.

   iii. For 66 KV and 33 KV class power transformers less than or equal to 5 MVA provided on either Transmission or Distribution System, over-current with high set instantaneous element along with auxiliary relays for transformer trip and alarm functions as per transformer requirements, shall be provided.

2. In addition to electrical protection, gas operated relays, winding temperature protection and oil temperature protection shall be provided.

16.8 Sub-Station Fire Protection

Adequate precautions shall be taken and protection shall be provided against fire hazards to all Apparatus of the Users conforming to relevant Indian Standard Specification and provisions in I.E. Rules or rules framed under Electricity Act 2003.

16.9 Calibration & Testing

The protection scheme shall be tested at each 220 KV, 132 KV, 66 KV sub-station by STU once in six months or immediately after any major fault, which ever is earlier.

Setting, co-ordination, testing and calibration of all protection schemes pertaining to generating units/stations shall be responsibility of respective SGS.

The overall co-ordination between Generators, Discoms and STU shall be decided in meeting of Protection Co-ordination Committee. The Protection Co-ordination Committee shall review the testing and calibration procedures as and when needed.

16.10 Data Requirements

Users shall provide STU with data for this section as specified in the Data Registration section.

PART V - METERING CODE

SECTION 17 METERING CODE

17.1 Introduction

This code prescribes a uniform policy in respect of electricity metering in the State Transmission System amongst the utilities i.e. STU, Generating Companies, Distribution Licensees and for the Open Access Customers on the State Transmission system and EHV Consumers of Distribution Licensees directly connected to the State Transmission System.

17.2 Objective

The objective of this code is to define minimum acceptable standards of metering which shall provide proper metering of the various operating system parameters for the purpose of accounting, commercial billing and settlement of electrical energy and to provide information which shall enable to operate the system in economic manner consistent with Licence conditions by Licensees and Generating Companies to effect management of generation and transmission in a safe and economical manner.

17.3 Scope

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

2. This code sets out or refers to the requirements of metering at generating stations, sub-stations and interfaces for tariff and operational metering.

3. This code also specifies the requirement for calibration, testing and commissioning of metering equipments viz. energy meters with associated accessories, current transformers and voltage transformers. The code broadly indicates the technical features of various elements of the metering, data communication and testing system, the procedure for assessment of consumption in case of defective and stuck-up meters and also lays down guidelines for resolution of disputes between different agencies.

17.4 Applicability

This Metering Code for Punjab Grid shall apply to:

i. STU/Transmission Licensees

ii. Generating Stations connected to State Transmission System

iii. Distribution Entities / Distribution Licensees connected with State Transmission System

iv. EHV Consumers of Distribution Licensee(s) directly connected to State Transmission System

v. Open Access Customers availing Open Access on State Transmission system

vi. Captive Generators connected to State Transmission System

17.5 Reference Standards

All the equipment installed under these Regulations/Code shall necessarily conform to the relevant standards as specified in the Central Electricity Authority’s Standards/Regulations on Installation and Operation of Meters

17.6 Meter Installation

1. Ownership

The ownership of the metering system shall be as provided in relevant agreement governing exchange of power and if no agreement exists then the ownership of the metering system shall belong to the User in whose premises the metering equipment is physically located. However, the responsibility for safety for the metering system is of the User in whose premises the metering equipment is physically located.

2. Right to Install Energy Meters
Each User shall extend necessary assistance and make available the required space to the other User for installation of the metering equipment and provide required outputs of the specified current and voltage transformers to facilitate installation of Meters, RTUs and associated equipment in their premises. Necessary auxiliary supply shall be extended up to the metering system, if meter can be powered by only external supply.

3. Access to Equipment and Data
Each User on request with advance notice, shall grant full right to install metering equipments and RTUs to other User's employees, agents/duly authorized representative. The other Users shall also have access to metering locations for inspecting, testing, calibrating, sealing, replacing the damaged equipment, collecting the data, joint readings of meters and metering equipments, and other functions necessary jointly or otherwise as mutually agreed.

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

5. Type of Meters and Metering Capability
The meters to be used shall be suitable for measurement of commercial transactions between the utilities according to applicable tariffs. The meters shall be all electronic (static) poly phase tri-vector type having facility to measure active, reactive and apparent energy/power in all four quadrants i.e. a true import export meter. All inter-user meters shall be bi-directional while capacitor bank meters and sub-station aux. meters shall be unidirectional if, bi-directional meters already exist, these will not be changed.

ABT compliant energy meters shall be provided at such interface points, wherever the energy exchange is based on Availability Based Tariff (ABT) according to CERC/PSERC Regulations/orders.

17.7 Various Standards for Metering Equipment

The minimum specifications for the metering equipment are given below, while detailed specifications are indicated as (APPENDIX-F).

Table 1

S. No.	Particulars	METER TYPE					
		Main & Check	Back up	Capacitor Bank	Sub-Stn Auxiliary	InterDiscom	Secondary Back up
1	2	3	4	5	6	7	8
(1)	**Accuracy class**						
(a)	Meter	0.2 S	0.2 S	0.5 S	1.0	0.2 S	0.2 S
(b)	CTs	0.2	0.2	0.2	0.2	0.2	0.2
(c)	PTs / CVTs	0.2	0.2	0.2	0.2	0.2	0.2
(d)	CT-PT sets for 33 KV & 11KV feeders	0.2	Existing	Existing	Existing	Existing	Existing
(2)	**Salient aspect of meters**						
(a)	Phase angle and ratio error compensation of CTs & PTs	No	No	No	No	No	No
(b)	**Communication port**						

(i)	Optical port	Yes	Yes	No	No	Yes	Yes
(ii)	For remote reading	Yes	Yes	No	No	Yes	Yes
(c)	Whether both Import & Export features required	Yes	Yes	No	No	Yes	Yes
(d)	Meter memory for 45 days	Yes	Yes	No	No	Yes	Yes

1. Minimum acceptable specifications for various metering equipments are enclosed at Appendixes detailed below:

1	Minimum acceptable specifications for Current Transformers (CT) for Metering	Appendix-F (1)
2	Minimum acceptable specifications for EHV Capacitor Voltage Transformers (CVT) for Metering	Appendix – F(2)
3	Minimum acceptable specifications for EHV Potential Transformers for Metering	Appendix – F(3)
4	Minimum acceptable specifications for dedicated HV Potential Transformers for Metering	Appendix – F(4)
5	Minimum acceptable specifications for dedicated CT-PT set for Metering	Appendix – F(5)
6	Minimum acceptable specifications for various types of meters	Appendix – F(6)

2. Minimum Technical Requirements for Energy Meter
   i. Operating System Parameters (for balanced and unbalanced load):
      a. Operating Voltage Range: The meter shall work satisfactorily on 110 Volts AC (Line-Line) or 415 Volts AC (Line-Line) with variation range of -40% to +20%.

      b. Operating Frequency Range: The meter shall work satisfactorily on 50 Hertz with variation range of -5% to +5%.

      c. Operating Power Factor Range: The meter shall work satisfactorily over a power factor range of zero lag to unity to zero lead.

   ii. Measuring Elements:
      a. The meter shall be 3 phase 4 wire type, capable to record and display import and export kWh, kVArh, kVAh and maximum demand in kW and kVA for 3 phase 4 wire AC balanced/unbalanced load for a power factor having range of zero lagging to unity to zero leading in all 4 quadrants. In addition, meter shall also be capable of displaying, on demand, the present status of supply/load, missing potential, CT polarity, current unbalance, anomaly occurrence and logging of occurrences as well as load survey data etc. which shall be down loaded to a user friendly Base Computer System (BCS) through portable data collection devices or CMRI which shall be connected to optical communication port of the meter. Meter shall be equipped with self-diagnostic features also and be capable of recording average values based on their integration on time base for kWh, kVArh, kVAh for at least 45 days. Meter shall be capable of measuring fundamental as well as total ener! gy including harmonics separately.

      b. Energy measurement during demand period shall be such that sampling in the meter is synchronized with the end of the time block otherwise energy measured in a demand period but not stored in that period shall be carried forward. An LED glow or pulse output coincident with end of each demand period need be provided in the meter so as to ensure that demand integration coincided the preset time block.

   iii. Display

      Present meter status, real time and date, cumulative energy registers, voltage, currents, power factor, present demand, frequency and meter serial number shall be available on demand through push button. Any interrogation/read operation shall not delete or alter any stored meter data.

iv. Memory

a. Numerical values of voltage/current, power factor and cumulative energy registers as well as anomalies/tempered details alongwith date and time of logging of and restoration of anomalies (subject to the meter memory space) shall be logged in the meter memory and shall be available for retrieving with the help of the data collection devices (CMRI) through meter optical port and down loading to BCS.

b. Memory in a static tri-vector meter shall not get 'erased' after reading or retrieving of data through CMRI. Data shall be retained for a minimum of 45 days or shall not get erased from meter until replaced by fresh data. However, desired data can be erased from CMRI, when memory of a CMRI becomes full after downloading of readings of a number of meters, as there is fixed space made available in CMRI for:

I. Energy registers.
II. Load survey data.
III. Anomaly data etc.

When a fresh data is logged in the memory, the oldest data shall disappear automatically.

v. Test terminal blocks

The test terminal blocks shall be provided on all meters to facilitate testing of meters in service. Main & back up meters of inter state / major generating stations shall be having the feature of draw out type modular units and shall have automatic CT short circuiting so that meter can be taken out for testing without shut down requirements.

vi. Meter Power Supply

Meters of inter state / major generating stations shall be capable of powered with 230 volt alternating current auxiliary supply and 110 volt or 220 volt DC supply of the substation so that metering core of PT/CVT is never loaded and in case of shut down on feeder/breaker, meter can be interrogated locally or remotely. It shall normally be powered by AC auxiliary supply and shall be switched over to DC supply only when AC auxiliary supply fails.

vii. Battery back-up

The meter shall have battery back up (2 years), for its Real Time Clock (RTC).

viii. Meter Programmability

The meters shall be equipped with necessary hardware/software to suit tariff requirements such as ABT, TOD, two-part tariff based on SMD as may be called for from time to time.

ix. Earthing System

The metering system shall be suitable for solidly earthed power system.

x. Meter Box

The meter box wherever required shall confirm to the degree of protection not less than IP-51 in accordance with IS 12063, and shall be capable of satisfactory operation in an indoor, non-air conditioned installation.

xi. Installation and Mounting

The meter shall be suitable for indoor or outdoor application. The meter can be mounted in dust proof, lockable and tamper proof panel or rack or metal box, as per requirement and site condition, conforming to minimum IP-31 in accordance with IS 12063.

3. Minimum Technical Requirement for Current Transformer (CT)

i. Three single-phase type current transformers shall be used for 3 phase 4 wire and 3 phase 3 wire measurement system. The secondary current rating of the CTs shall be 1 Ampere particularly for 220 KV, 132 KV, 66 KV measurements. However existing CTs with 5-Ampere secondary current shall also be acceptable provided the connected meters and instrument have base 5 Ampere current rating. For other voltages, 1 Ampere or 5 Ampere shall be employed.

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

iii. The total burden connected to each current transformer shall not exceed the rated burden of CT. Total circuit burden shall be kept close to rated burden of CT for minimum error.

iv. Minimum acceptable specifications are enclosed in (APPENDIX-F).

4. Minimum Technical Requirement for Voltage Transformers (VT)
   i. Either Electromagnetic Voltage Transformers (EVT) or Capacitive Voltage transformer (CVT) should be used for metering purpose. Generally, term VT is used to cover either EVT or CVT. The secondary voltage per phase shall be $110/3^{1/2}$ volts or $415/3^{1/2}$ volts. Either dedicated VTs or dedicated core of VTs shall be provided for metering and that wherever feasible, VTs (or their cores) feeding to main meters and backup/check meters shall be separate. Fuses of proper rating shall be provided at appropriate locations in the VT circuit.

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

   iii. The total burden connected to each VT shall not exceed the rated burden of VT. Voltage drop in VT leads shall be within the permissible limits.

   iv. The current transformers and voltage transformers shall meet the requirements as per the relevant standards. Where a combined CT/PT unit is provided, the accuracy shall be as specified under relevant IS.

   v. Minimum acceptable specifications are enclosed in (APPENDIX-F).

5. Minimum Technical Requirement for Remote Transmitting Unit (RTU)
   i. Following data (instantaneous system parameters) shall be made available through transducers and RTUs from selected individual stations to Sub-Area Load Despatch Centre and State Load Despatch Centre continuously.
      - MW (Import/export).
      - MVAr (Lag plus lead).
      - Voltage.
      - Current.
      - Frequency.
      - The status of various isolators, circuit breakers and transformer tap positions.

   ii. Single transducer giving output of MW, MVAr, voltage, frequency and ampere shall be preferred in place of individual transducers for each metering point. The transducers shall be connected to 0.2 class CTs and VTs and housed inside the meter box of the check meter meant for metering purpose.

   iii. Since the above metering scheme is for commercial metering purpose therefore the complete CT wiring including energy meter, meter test terminal block and transducers shall be housed in the metering cubicle which shall be kept sealed. The output of the transducers shall be connected to RTU through screened signal cable. The RTUs shall be located in the communication equipment room. The size of the CT & VT cable to the transducer shall be same as that provided in the metering circuit.

   iv. The various data collected by transducers and fed to RTU shall be processed in the RTU and output

will be provided in digital telegraphic form. Transmission of these data to the load despatch centre can be through any of the communication medium like micro-wave Radio frequency, PLCC (Power Line Carrier Communication), PSTN (Public Switched Telephone Network), VSAT, Mobile and other means of Telemetering like private network of STU or low power radio. The data shall be again processed at load despatch end in Data Concentrator Unit and converted to analog data and displayed on the monitor screen. The RTU shall be utilized for monitoring and also for remote control of feeders / breakers located at remote sub-stations.

17.8 Testing Arrangement

i. Two types of test facilities shall be available:
   a. Automatic meter test bench with high accuracy, static source and 0.02S class electronic reference standard meter (RS Meter) shall be used for testing and calibration of meters. Meter Testing Laboratories duly equipped with testing benches and other equipments shall be established at suitable locations for testing and calibration of meters by STU. The Meter Testing benches with 0.02S-class reference standard meter shall also be used for checking and calibration of portable testing equipments. Testing, calibration and maintenance of Energy Meters shall conform to the requirement of IS: 9792 and Testing equipments shall conform to Indian Standards Specification IS: 12346.

   b. Portable test set with static source and electronic reference meter of 0.1 class shall be used for verification and joint testing of accuracy of static tri-vector meters at site on regular/routine basis.

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

iii. Testing in situ shall be carried out as follows:
   - All meters where power handled is normally more than 10 MW- once in six months.

   - All meters where power handled is normally less than 10 MW – once in two years.

iv. Subject to Regulations issued by the Commission in this regard, the Licensee shall allow the testing of Open Access Customers' meters at third party NABL approved Testing Labs in case the Customers so request for the same. In case of testing by third party NABL approved Testing Labs, the Open Access Customers shall apply with prescribed fee to the Licensee.

17.9 Meter Reading, Data Collection and Data Downloading

i. The STU and concerned Generating Companies, CPP /Distribution Licensees, Open Access Customers as the case may be shall jointly read the meters through their authorized representatives on 1st of every month at 12.00 Hrs. / retrieve meter reading data using CMRI/Tele metering.

ii. Where a smart meter has been installed for an Open Access Customer connected to the transmission system, the Distribution Licensee shall be required to keep a metering database of the meter readings for the consumer for:
   a. 13 months in an accessible format;
   b. 5 years in archive.

17.10 Rights of access to metering data

The only persons entitled to access to metering data from a metering installation shall be:
   a. The Distribution or Transmission Licensee who is responsible for the metering installation;

   b. The State Load Despatch Centre;
   c. The Transmission Licensee;
   d. The consumer of electricity or the generator of electricity at the metering installation as the case may be;

e. Any other person having an agreement to supply electricity to the consumer associated with that metering installation.
In relation to sub-clause (e), the person must present a written authorisation from the consumer to the Distribution Licensee before the data is to be provided; and

f. The Commission when such information is required for an investigation.

17.11 System for Joint Inspection, Testing, Calibrations

i. The metering system located at metering points between Generating Companies, STU and Distribution Licensees shall be regularly inspected at least once in a year or at an interval lesser than 1 year as mutually agreed by both the agencies involved for despatch and receipt of energy. Since the static tri-vector meters are calibrated through software at the manufacturers' works, only accuracy of the meters and functioning shall be verified during joint inspection and certified jointly by both the agencies. To cover for loss of time, spare meters shall always be kept available with the owner of the meter/metering point. After testing, the meter shall be properly sealed and a joint report shall be prepared giving details of testing work carried out, details of old seals removed and new seals affixed, test results, further action to be taken (if any) etc. The agency in whose premises the meter is located shall be responsible for proper security,! protection of the metering equipment and sealing arrangement.

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

17.12 Sealing

i. Tariff metering systems shall be jointly sealed by the authorized representatives of the concerned agencies as per the procedure agreed upon.

ii. Any seal, applied pursuant to this metering code, shall not be broken or removed except in the presence of or with the prior consent of the agency affixing the seal or on whose behalf the seal has been affixed unless it is necessary to do so in circumstances where (a) both main and check meters are malfunctioning or there occurs a fire or similar hazard and such removal is essential and such consent can not be obtained immediately (b) such action is required for the purpose of attending to the meter failure. In such circumstances, verbal consent shall be given immediately and it must be confirmed in writing forthwith.

iii. Each agency shall control the issue of its own seals and sealing pliers, and shall keep proper register/record of all such pliers and the authorized persons to whom these are issued.

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

17.13 Assessment of consumption of defective and/or stuck-up meter

In case of excessive / less consumption or stoppage of meter, burning/damage of the meter or damage to the seals, the meter shall be considered as defective. In case of difference in consumption between the main and check meter being more than 0.4%, the testing of main meter using the portable test set shall be carried out immediately to determine the accuracy of the main meter.

Whenever a meter goes defective, the consumption recorded by the check meter / backup meter / secondary backup (i.e. receiving end meters) shall be referred to. The details of the malfunctioning along with date and time and snaps shot parameters along with load survey shall be retrieved from the main meter. The exact nature of the mal-functioning shall be brought out after analyzing the data so retrieved and the consumption / losses recorded by the main meter shall be assessed accordingly. If main as well as back up metering systems become defective, the assessment of energy consumption for the outage period shall be done from the secondary backup meters by the concerned agencies as mutually agreed or at the level of Commercial & Metering Committee.

If main as well as check metering systems become defective, the assessment of energy consumption for the

outage period shall be done by the concerned agencies as mutually agreed or at the level of Commercial & Metering Committee.

17.14 Replacement of Defective or Stuck-up Meter

Defective or stuck-up meter shall be replaced as soon as possible. The owner of the meter shall maintain spare inventory of meters in sufficient quantity, so that down time is minimized.

17.15 Interface Metering Arrangement

The metering system shall comprise of main, check, backup and secondary backup meters. In the event of main meter becoming defective the order of precedence for billing shall be (a) main (b) check (c) backup (d) secondary backup.

i. Generating Stations:
   a. Meters shall be installed on each Generator terminal, at each Unit Auxiliary Transformer (UAT), and all outgoing feeders at Generating Stations to work out energy generated and net energy delivered by the Power Station in the Grid.

   b. For measurement of energy supplied by major generating stations within the state, meters shall be provided on each outgoing feeder at the power station designated as main meter for billing purpose as per commercial agreement and/or State Grid Code Connectivity Conditions.

   c. A Check Meter shall also be provided along with the Main Meter. Meters on each generator and each auxiliary transformer shall work as backup meters.

ii. Interstate Transmission and Inter-Regional Transmission System:
Metering arrangement for Inter-State Transmission Lines and for Inter-Regional Transmission System shall be governed by IEGC. Special Energy Meters (SEM) capable of time-differentiated measurement (15 minutes) of active energy and voltage differentiated measurement of reactive energy as specified by CTU/NRLDC shall be provided on interstate and inter-regional transmission lines. STU shall comply with requirement for installation, meter reading & downloading and communication of readings of Special Energy Meters (SEM) to NRLDC as per operating procedure of NRLDC. STU may install its own Check Meters at inter-state/inter-regional transmission lines at the periphery of State Transmission System.

iii. Special requirement
The above meters provided on inter-state/ inter-regional transmission lines, and on the lines connected to major generating stations within the state shall have following facilities:
   a. Metering equipment shall have external / internal modem so as to be capable of remote transmission of all data available in the meter memory through any of the information link viz. radio frequency, Public Switched Telephone Network (PSTN), Power Line Carrier Communication (PLCC) lines, Microwave, V-SAT Network, Mobile and other means of telemetry like private network of STU or low power radio.

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

   c. the meter shall be capable of data transmission to RTU's as well Intelligent Electronic Device (IED). The format / protocol of communication for data retrieval and data telex should be made known to owner of meter by the concerned meter supplier.

iv. Metering between STU-Distribution Licensee
   a. For measurement of power delivered by STU to Distribution Licensee, metering shall be provided on the LV side of EHV Power Transformer i.e. 66 KV side of 220/66 KV or 132/66 KV and 33 KV side of 132/33 KV or 66/33 KV and 11 KV side of 132/33/11 KV or 66/33/11 KV and 11 KV side of 132/11 KV or 66/11 KV transformers installed in EHV sub-stations.

   b. Operational meters shall also be provided on all outgoing 66 KV, 33 KV and 11 KV feeders as

back-up meter for energy audit on feeder and reconciliation of energy with respect to energy measured on LV side of EHV Power Transformer.

c. In case of EHV industrial and other consumers directly fed from 220 KV or 132 KV or 66 KV sub-stations, tariff metering shall be provided on outgoing feeder emanating from EHV sub-station.

v. Metering between two Distribution Licensee:
   a. The energy metering shall be provided at such points of the power lines connecting any two Distribution Systems owned by different Distribution Licensees so that the measured energy gives correct measurement of consumption by either Distribution Licensee.

   b. If installation of metering at such point is not feasible, it shall be provided at nearest sub-station feeding other Distribution System. In such case, energy accounting may be in proportion to installed capacity of Distribution Transformers on the line or as agreed mutually.

vi. Sub-station Auxiliary Consumption Metering:
The STU sub-stations auxiliary consumption shall be recorded on LV side of station auxiliary transformers. If such transformer(s) is feeding other local load (colony quarters, streetlights etc.) apart from sub-station auxiliary load, separate metering shall be provided on individual feeders.

vii. Open Access Customers
The Inter-State Open Access Customers shall provide Special Energy Meters. The embedded Open Access Customers within the State Transmission System shall also provide Special Energy Meters both at the point of injection and point of drawal of supply. Special Energy Meters (SEM) shall be capable of time-differentiated measurement (15 minutes) of active energy and voltage differentiated measurement of reactive energy as specified by CTU/ NRLDC.
The Distribution licensee may provide Check Meters of the same specification as Main Meters.

viii. Operational Metering:
Operational metering shall be sited wherever reasonably required by STU/Generating Companies for applications other than tariff metering.

17.16 ABT, Two Part and ToD Tariff Capability

The ABT compliant meter will have provision to compute and store average active and reactive energy and load data with respect to system frequency and the integration of the data i.e. average kWh & kVarh, and average frequency for 15 minutes block will be available in each meter.

Meters shall also have reactive high and reactive low volt-ampere hour registers for total drawal, high & low system voltage drawal. The Distribution Licensee wise summation of kWh, kW, PF, demand, scheduled interchange/ unscheduled interchange will be done at the main computer station provided at central billing station or at Load Despatch Centre.

The metering arrangement for recording Distribution Licensee consumption/power input in his area of supply shall consist of following:

i. Frequency based ABT compliant meters shall be provided on 66 kV or lower voltage lines feeding each Distribution Licensee area of supply. The function of these meters will be as under:
   a. To measure Distribution Licensee-wise UI (Unscheduled Interchange) energy and corresponding average frequency during 15 minute block.

   b. The Distribution Licensee wise summation of kWh, kW, PF, demand, scheduled interchange/ unscheduled interchange will be done at the main computer station provided at central billing station or at Load Despatch Centre.

   c. For this purpose, the various parameters shall be integrated at one centrally located station preferably at State Load Despatch Centre at Patiala through computer and suitable software.

ii. Static tri-vector meters to be provided on LV secondary side of all EHV transformers. The function/duty of this meter will be as under:

a. Measurement of kWh energy supplied to Distribution Licensee for billing purpose.

b. kW/ kVA demand and power factor, 15 minute block-wise as well monthly caused by Discom on each EHV transformer.

PART VI - DATA REGISTRATION CODE

SECTION 18 DATA REGISTRATION

18.1 Introduction:

This section contains a list of all data required by STU and SLDC, which is to be provided by Users, and data required by Users to be provided by STU at times specified in the State Grid Code. Other section of the State Grid Code contains the obligation to submit the data and defines the times when data is to be supplied by Users.

18.2 Objective

The objective of this section is to list out all the data required to be provided by Users to STU and vice versa, in accordance with the provisions of the State Grid Code.

18.3 Responsibility

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

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

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

4. STU shall provide up-to-date data to Users as provided in the relevant schedule of the State Grid Code.

5. Responsibility for the correctness of data rests with the concerned User providing the data.

18.4 Data Categories and Stages in Registration

1. Data required to be exchanged has been listed in the Appendices to this section under various categories with cross-reference to the concerned sections.

2. Changes to Users Data
Whenever any User becomes aware of a change to any items of data that is registered with STU, the User must promptly notify STU of the changes. STU on receipt of intimation of the changes shall promptly correct the database accordingly. This shall also apply to any data compiled by STU regarding its own system.

3. Methods of Submitting Data

The data shall be furnished in the standard formats for data submission and such formats must be used for the written submission of data to SLDC/STU.

Where standard formats are not enclosed these would be developed by SLDC / STU in consultation with Users.

All data to be submitted under the Schedule(s) must be submitted to SLDC / STU or to such other department and/or entity as STU may from time to time notify to Users. The name of the Person who is submitting each schedule of data must be indicated.

Where a computer data link exists between a User and SLDC/ STU, data may be submitted via this link. The data shall be in the same format as specified for paper transmission except for electronic encoding for which some other format may be more suited. The User shall specify the method to be used in consultation with the SLDC/ STU and resolve issues such as Protocols, transmission speeds etc. at the time of transmission.

Other modes of data transfer, such as magnetic tape may be utilised if SLDC/ STU gives its prior written consent.

4. Data not supplied

Users are obliged to supply data as referred to in the individual sections of the State Grid Code and listed out in the Data Registration section Appendices. In case any data is not supplied by any User or is not available, STU or SLDC may, acting reasonably, if and when necessary, estimate such data depending upon the urgency of the situation. Similarly, in case any data is not supplied by STU, the concerned User may, acting reasonably, if and when necessary, estimate such data depending upon urgency of the situation. Such estimates will in each case, be based upon corresponding data for similar plant or Apparatus or upon such other information, the User or STU or SLDC, as the case may be, deemed appropriate.

18.5 Special Considerations

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

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

APPENDIX A: STANDARD PLANNING DATA

Standard Planning Data consist of details, which are expected to be normally sufficient for STU to investigate the impact on the State Transmission System due to User development.
Standard planning data covering (a) preliminary project planning

REFERENCE TO: SECTION 4 AND SECTION 5

A-1 STANDARD PLANNING DATA (GENERATION)

For SGS – Thermal

A.1.1 THERMAL (COAL / GAS/FUEL LINKED)

A.1.1.1 GENERAL

i	Site	Give location map to scale showing roads, railway lines, Transmission lines, canals, pondage and reservoirs if any.
ii	Coal linkage/ Fuel (Like Liquefied Natural Gas, Naphtha etc.) linkage	Give information on means of coal transport / carriage. In case of other fuels, give details of source of fuel and their transport.
iii	Water Sources	Give information on availability of water for operation of the Power Station.
iv	Environmental	States whether forest or other land areas are affected.
v	Site Map (To Scale)	Showing area required for Power Station coal linkage, coal yard, water pipe lines, ash disposal area, colony etc.
vi	Approximate period of construction	

A.1.1.2 CONNECTION

I	Point of Connection	Give single line diagram of the proposed Connection with the system.

ii	Step up voltage for Connection (kV)	

A.1.1.3 STATION CAPACITY

i	Total Power Station capacity (MW)	State whether development will be carried out in phases and if so, furnish details.
ii	No. of units & unit size (MW)	

A.1.1.4 GENERATING UNIT DATA

i	Steam Generating Unit	State type, capacity, steam pressure, stream temperature etc.
ii	Steam turbine	State type, capacity.
iii	Generator	Type Rating (MVA) Speed (RPM) Terminal voltage (KV) Rated Power Factor Reactive Power Capability (MVAr) in the range 0.95 of leading and 0.85 lagging Short Circuit Ratio Direct axis (saturated) transient reactance (% on MVA rating) Direct axis (saturated) sub-transient reactance (% on MVA rating) Auxiliary Power Requirement MW and MVAr Capability curve Ramp-up and ramp-down rate Generator Characteristic curve
iv	Generator Transformer	Type Rated capacity (MVA) Voltage Ratio (HV/LV) Tap change Range (+ % to - %) Percentage Impedance (Positive Sequence at Full load)

A.1.2 HYDRO ELECTRIC

For SGS – Hydro

A.1.2.1 GENERAL

i	Site	Give location map to scale showing roads, railway lines, and transmission lines.
ii	Site map (To scale)	Showing proposed canal, reservoir area, water conductor system, fore-bay, power house etc.
iii	Submerged Area	Give information on area submerged, villages submerged, submerged forest land, agricultural land etc
iv	Whether storage type or run of river type	
v	Whether catchment receiving discharges from other reservoir or power plant.	
vi	Full reservoir level	
vii	Minimum draw down level.	
viii	Tail race level	
ix	Design Head	
x	Reservoir level v/s energy potential curve	
xi	Restraint, if any, in water discharges	
xii	Approximate period of construction.	

A.1.2.2 CONNECTION

		Give single line diagram proposed Connection with the Transmission

i	Point of Connection	System.
ii	Step up voltage for Connection (kV)	

A.1.2.3 STATION CAPACITY

i	Total Power Station capacity (MW)	State whether development is carried out in phases and if so furnish details.
ii	No. of units & unit size (MW)	

A.1.2.4 GENERATING UNIT DATA

i	Operating Head (in Metres)	a. Maximum b. Minimum c. Average
	Hydro Unit	Capability to operate as synchronous condenser Water head versus discharges curve (at full and part load) Power requirement or water discharge while operating as synchronous condenser
i	Turbine	State Type and capacity
iii	Generator	Type Rating (MVA) Speed (RPM) Terminal voltage (KV) Rated Power Factor Reactive Power Capability (MVAr) in the range 0.95 of leading and 0.85 of lagging MW & MVAr capability curve of generating unit Short Circuit Ratio Direct axis transient (saturated) reactance (% on rated MVA) Direct axis sub-transient (saturated) reactance (% on rated MVA) Auxiliary Power Requirement (MW)
iv	Generator - Transformer	a. Type b. Rated Capacity (MVA) c. Voltage Ratio HV/LV d. Tap change Range (+% to -%) e. Percentage Impedance (Positive Sequence at Full Load).

A.2 STANDARD PLANNING DATA (TRANSMISSION)

For STU and Transmission Licensees

Note: The compilation of the data is the internal matter of STU, and as such STU shall make arrangements for getting the required data from different Departments of STU/other transmission licensees (if any) to update its Standard Planning Data in the format given below:

i. Name of line (Indicating Power Stations and substations to be connected).
ii. Voltage of line (KV).
iii. No. of circuits.
iv. Route length (km).
v. Conductor sizes.
vi. Line parameters (PU values).
vii. Resistance/km
viii. Inductance/km
ix. Susceptance/ km (B/2)
x. Approximate power flow expected- MW & MVAr.
xi. Terrain of the route- Give information regarding nature of terrain i.e. forest land, fallow land, agricultural and river basin, hill slope etc.
xii. Route map (to scale) - Furnish topographical map showing the proposed route showing existing power lines and telecommunication lines.
xiii. Purpose of Connection- Reference to Scheme, wheeling to other States etc.
xiv. Approximate period of Construction.

A.3. STANDARD PLANNING DATA (DISTRIBUTION)

For Discoms and distribution licensees

A.3.1 GENERAL

i	Area Map (to scale)	Furnish map of Punjab duly marked with the area of supply relevant for the Distribution Licence .
ii	Consumer Data	Furnish categories of consumers, their numbers and connected loads.
iiii	Reference to Electrical Divisions presently in charge of the Distribution.	

A.3.2 CONNECTION

i	Points of Connection	Furnish single line diagram showing points of Connection
ii	Voltage of supply at points of Connection	
iii	Names of Grid Sub-Station feeding the points of Connection	

A.3.3 LINES AND SUBSTATIONS

i	Line Data	Furnish lengths of line and voltages within the Area.
ii	Sub-station Data	Furnish details of 66/11 KVsub-station, 33/11 KV sub-station, 11/0.4 KV sub-stations, capacitor installations

A.3.4 LOADS

i	Loads drawn at points of Connection.
ii	Details of loads fed at EHV, if any. Give name of consumer, voltage of supply, contract demand/load and name of Grid Sub-station from which line is drawn, length of EHV line from Grid Sub-station to consumer's premises.
iii	Reactive Power compensation installed

A.3.5 DEMAND DATA (FOR ALL LOADS 1 MW AND ABOVE)

i	Type of load	State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads etc.
ii	Rated voltage and phase	
iii	Electrical loading of equipment	State number and size of motors, types of drive and control arrangements.
iv	Power Factor	
v	Sensitivity of load to voltage and frequency of supply.	
vi	Maximum Harmonic content of load.	
vii	Average and maximum phase unbalance of load.	
viii	Nearest sub-station from which load is to be fed.	
ix	Location map to scale	Showing location of load with reference to lines and sub-stations in the vicinity.

A.3.6 LOAD FORECAST DATA

i	Peak load and energy forecast for each category of loads for each of the succeeding 5 years.
ii	Details of methodology and assumptions on which forecasts are based.
iii	If supply is received from more than one substation, the sub-station wise break up of peak load and energy projections for each category of loads for each of the succeeding 5 years along with estimated Daily load curve.
iv	Details of loads 1 MW and above. a. Name of prospective consumer. b. Location and nature of load/complex.

c. Sub-Station from which to be fed.
d. Voltage of supply.
e. Phasing of load.

APPENDIX B: DETAILED PLANNING DATA
REFER TO: SECTION 4 & SECTION 5
FOR ROUTINE SUBMISSION

B.1 DETAILED PLANNING DATA (GENERATION)

B.1.1 THERMAL POWER STATIONS

For SGS – Thermal

B.1.1.1 GENERAL

i. Name of Power Station.
ii. Number and capacity of Generating Units (MVA).
iii. Ratings of all major equipments (Boilers and major accessories, Turbines, Alternators, Generator Unit Transformers etc).
iv. Single line Diagram of Power Station and switchyard.
v. Relaying and metering diagram.
vi. Neutral Grounding of Generating Units.
vii. Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors)
viii. Earthing arrangements with earth resistance values.

B.1.1.2 PROTECTION AND METERING

i. Full description including settings for all relays and protection systems installed on the Generating Unit, Generator unit Transformer, Auxiliary Transformer and electrical motor of major equipments listed, but not limited to, under Sec. 3 (General).
ii. Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, Tie circuit breakers, and incoming circuit breakers.
iii. Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System.
iv. Most probable fault clearance time for electrical faults on the User's System.
v. Full description of operational and commercial metering schemes.

B.1.1.3 SWITCHYARD

i. In relation to interconnecting transformers:
    1. Rated MVA.
    2. Voltage Ratio.
    3. Vector Group.
    4. Positive sequence reactance for maximum, minimum, normal Tap. (% on MVA).
    5. Positive sequence resistance for maximum, minimum, normal Tap. (% on MVA).
    6. Zero sequence reactance (% on MVA).
    7. Tap changer Range (+% to -%) and steps.
    8. Type of Tap changer. (off/on load).
ii. In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of Connection:
    1. Rated voltage (kV).
    2. Type of circuit breaker (MOCB/ABCB/SF6).
    3. Rated short circuit breaking current (kA) 3 phase.
    4. Rated short circuit breaking current (kA) 1 phase.
    5. Rated short circuit making current (kA) 3 phase.
    6. Rated short circuit making current (kA) 1-phase.
    7. Provisions of auto reclosing with details.
iii. In relation to the Lightning Arresters -
Technical data
iv. In relation to the Communication - Details of communication equipment installed at points of connections.
v. In relation to the Basic Insulation Level (kV) -

1. Bus bar.
2. Switchgear.
3. Transformer bushings.
4. Transformer windings.

B.1.1.4 Parameters of Generating Units

i. Rated terminal voltage (kV).
ii. Rated MVA.
iii. Rated MW.
iv. Speed (rpm) or number of poles.
v. Inertia constant H (MW Sec./MVA).
vi. Short circuit ratio.
vii. Direct axis synchronous reactance (% on MVA) Xd.
viii. Direct axis (saturated) transient reactance (% on MVA) Xd'.
ix. Direct axis (saturated) sub-transient reactance (% on MVA) Xd".
x. Quadrature axis synchronous reactance (% on MVA) Xq .
xi. Quadrature axis (saturated) transient reactance (% on MVA) Xq'.
xii. Quadrature axis (saturated) sub-transient reactance (% on MVA) Xq".
xiii. Direct axis transient open circuit time constant (Sec) T'do.
xiv. Direct axis sub-transient open circuit time constant (See) T"do.
xv. Quadrature axis transient open circuit time constant (Sec) T’qo.
xvi. Quadrature axis sub-transient open circuit time constant (Sec) T’'qo.
xvii. Stator Resistance (Ohm)Ra.
xviii. Neutral grounding details.
xix. Stator leakage reactance (Ohm) X1.
xx. Stator time constant (Sec).
xxi. Rated Field current (A).
xxii. Open Circuit saturation characteristic for various terminal Voltages giving the compounding current to achieve the same.
xxiii. MW and MVAr Capability curve

B.1.1.5 Parameters of excitation control system:

i. Type of Excitation.
ii. Maximum Field Voltage.
iii. Minimum Field Voltage.
iv. Rated Field Voltage.
v. Details of excitation loop in block diagrams showing transfer functions of individual elements using I.E.E.E. symbols.
vi. Dynamic characteristics of over - excitation limiter.
vii. Dynamic characteristics of under-excitation limiter.

B.1.1.6 Parameters of governor:

i. Governor average gain (MW/Hz).
ii. Speeder motor setting range.
iii. Time constant of steam or fuel Governor valve.
iv. Governor valve opening limits.
v. Governor valve rate limits.
vi. Time constant of Turbine.
vii. Governor block diagram showing transfer functions of individual elements using I.E.E.E. symbols.

B.1.1.7 Operational parameters:

Minimum notice required to synchronize a Generating Unit from de- synchronization.

i. Minimum time between synchronizing different Generating Units in a Power Station.
ii. The minimum block load requirements on synchronizing.
iii. Time required for synchronizing a Generating Unit for the following conditions:

1. Hot
2. Warm
3. Cold

iv. Maximum Generating Unit loading rates for the following conditions:
1. Hot
2. Warm
3. Cold

v. (v) Minimum load without oil support (MW).

B.1.1.8 GENERAL STATUS

i. Detailed Project report.
ii. Status Report
1. Land
2. Coal
3. Water
4. Environmental clearance
5. Rehabilitation of displaced persons

iii. Techno-economic approval by Central Electricity Authority (CEA).
iv. Approval of State Government/Government of India.
v. Financial Tie-up.

B.1.1.9 CONNECTION

i. Reports of Studies for parallel operation with the State Transmission System.
ii. Short Circuit studies
iii. Stability Studies.
iv. Load Flow Studies.
v. Proposed Connection with the State Transmission System.
a. Voltage
b. No. of circuits
c. Point of Connection.

B.1.2 HYDRO - ELECTRIC STATIONS

For SGS – Hydro

B.1.2.1 GENERAL

i. Name of Power Station.
ii. No and capacity of units. (MVA)
iii. Ratings of all major equipment.
a. Turbines (HP)
b. Generators (MVA)
c. Generator Transformers (MVA)
d. Auxiliary Transformers (MVA)

iv. Single line diagram of Power Station and switchyard.
v. Relaying and metering diagram.
vi. Neutral grounding of Generator.
vii. Excitation control.
viii. Earthing arrangements with earth resistance values.
ix. Reservoir Data.
a. Salient features
b. Type of Reservoir
1. Multipurpose
2. For Power

c. Operating Table with
1. Area capacity curves and
2. Unit capability at different net heads

B.1.2.2 PROTECTION

i. Full description including settings for all relays and protection systems installed on the Generating Unit, Generator transformer, auxiliary transformer and electrical motor of major equipment included, but not limited to those listed, under Sec. 3 (General).
ii. Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, tiebreakers, and incoming breakers.
iii. Full description of inter-tripping of breakers at the point or points of Connection with the Transmission System.
iv. Most Probable fault clearance time for electrical faults on the User's System.

B.1.2.3 SWITCHYARD

i. Interconnecting transformers:
    1. Rated MVA
    2. Voltage Ratio
    3. Vector Group
    4. Positive sequence reactance for maximum, minimum and normal Tap.(% on MVA).
    5. Positive sequence resistance for maximum, minimum and normal Tap.(% on MVA).
    6. Zero sequence reactance (% on MVA)
    7. Tap changer range (+% to -%) and steps.
    8. Type of Tap changer (off/on load).
    9. Neutral grounding details.
ii. Switchgear (including circuit breakers, Isolators on all circuits connected to the points of Connection).
    1. Rated voltage (KV).
    2. Type of Breaker (MOCB/ABCB/SF6).
    3. Rated short circuit breaking current (KA) 3 phase.
    4. Rated short circuit breaking current (KA) 1 phase.
    5. Rated short circuit making current (KA) 3 phase.
    6. Rated short circuit making current (KA) 1 phase.
    7. Provisions of auto reclosing with details.
iii. Lightning Arresters
Technical data
iv. Communications
Details of Communications equipment installed at points of connections.
v. Basic Insulation Level (KV)
    1. Bus bar.
    2. Switchgear.
    3. Transformer Bushings
    4. Transformer windings.

B.1.2.4 GENERATING UNITS

i. Parameters of Generator
    1. Rated terminal voltage (KV).
    2. Rated MVA.
    3. Rated MW
    4. Speed (rpm) or number of poles.
    5. Inertia constant H (MW sec./MVA).
    6. Short circuit ratio.
    7. Direct axis synchronous reactance Xd (% on MVA).
    8. Direct axis (saturated) transient reactance (% on MVA) X'd.
    9. Direct axis (saturated) sub-transient reactance (% on MVA) X"d.
    10. Quadrature axis synchronous reactance (% on MVA) Xq.
    11. Quadrature axis (saturated) transient reactance (% on MVA) X'q.
    12. Quadrature axis (saturated) sub-transient reactance (% on MVA) X"q.
    13. Direct axis transient open circuit time constant (sec) T'do.
    14. Direct axis sub-transient open circuit time constant (sec) T"do.
    15. Quadrature axis transient open circuit time content (sec) T'qo.

16. Quadrature axis transient open circuit time constant (sec) T"qo.
17. Stator Resistance (Ohm) Ra.
18. Stator leakage reactance (Ohm) X1.
19. Stator time constant (Sec).
20. Rated Field current (A).
21. Neutral grounding details.
22. Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this.
23. Type of Turbine.
24. Operating Head (Metres)
25. Discharge with full gate opening (cumecs)
26. Speed Rise on total Load throw off(%).
27. MW and MVAr Capability curve

ii. Parameters of excitation control system:
iii. Parameters of governor:
iv. Operational parameter:
    1. Minimum notice required to Synchronise a Generating Unit from de-synchronisation.
    2. Minimum time between Synchronising different Generating Units in a Power Station.
    3. Minimum block load requirements on Synchronising.

B.1.2.5 GENERAL STATUS

i. Detailed Project Report.
ii. Status Report.
    1. Topographical survey
    2. Geological survey
    3. Land
    4. Environmental Clearance
    5. Rehabilitation of displaced persons.
iii. Techno-economic approval by Central Electricity Authority.
iv. Approval of State Government/Government of India.
v. Financial Tie-up.

B.1.2.6 CONNECTION

i. Reports of Studies for parallel operation with the State Transmission System.
    1. Short Circuit studies
    2. Stability Studies.
    3. Load Flow Studies.
ii. Proposed Connection with the State Transmission System.
    1. Voltage
    2. No. of circuits
    3. Point of Connection.

B.1.2.7 RESERVOIR DATA

i. Dead Capacity
ii. Live Capacity

B.2 DETAILED SYSTEM DATA – TRANSMISSION

For STU/Transmission Licensees

B.2.1 GENERAL

i. Single line diagram of the Transmission System down to 66KV,33KV bus at Grid Sub-station detailing:
    1. Name of Sub-station.

2. Power Station connected.
3. Number and length of circuits.
4. Interconnecting transformers.
5. Sub-station bus layouts.
6. Power transformers.
7. Reactive compensation equipment.

ii. Sub-station layout diagrams showing:

1. Bus bar layouts.
2. Electrical circuitry, lines, cables, transformers, switchgear etc.
3. Phasing arrangements.
4. Earthing arrangements.
5. Switching facilities and interlocking arrangements.
6. Operating voltages.
7. Numbering and nomenclature:
8. Transformers.
9. Circuits.
10. Circuit breakers.
11. Isolating switches.

B.2.2 LINE PARAMETERS (for all circuits)

i. Designation of Line.

1. Length of line (km).
2. Number of circuits.Per Circuit values.
3. Operating voltage (KV).
4. Positive Phase sequence reactance (pu on 100 MVA) X1
5. Positive Phase sequence resistance (pu on 100 MVA) R1
6. Positive Phase sequence susceptance (pu on 100 MVA) B1
7. Zero Phase sequence reactance (pu on 100 MVA) X0
8. Zero Phase sequence resistance (pu on 100 MVA) R0
9. Zero Phase sequence susceptance (pu on 100 MVA) B0

B.2.3 TRANSFORMER PARAMETERS (For all transformers)

i. Rated MVA
ii. Voltage Ratio
iii. Vector Group
iv. Positive sequence reactance, maximum, minimum and normal (pu on 100 MVA) X1
v. Positive sequence resistance, maximum, minimum and normal (pu on 100 MVA) R1
vi. Zero sequence reactance (pu on 100 MVA).
vii. Tap change range (+% to -%) and steps.
viii. Details of Tap changer. (Off/On load).

B.2.4 EQUIPMENT DETAILS (For all substations)

i. Circuit Breakers
ii. Isolating switches
iii. Current Transformers
iv. Potential Transformers /CVTs

B.2.5 RELAYING AND METERING

i. Protection relays installed for all transformers and feeders along with their settings and level of co-ordination with other Users.
ii. Metering Details.

B.2.6 SYSTEM STUDIES

i. Load Flow studies (Peak and lean load for maximum hydro and maximum thermal generation).
ii. Transient stability studies for three-phase fault in critical lines.
iii. Dynamic Stability Studies
iv. Short circuit studies (three-phase and single phase to earth)
v. Transmission and Distribution Losses in the Transmission System.

B.2.7 DEMAND DATA (For all substations)

Demand Profile (Peak and lean load).

B.2.8 REACTIVE COMPENSATION EQUIPMENT

i. Type of equipment (fixed or variable).
ii. Capacities and/or Inductive rating or its operating range in MVAr.
iii. Details of control.
iv. Point of Connection to the System.

B.3 DETAILED PLANNING DATA (DISTRIBUTION)

For Discoms /Distribution Licensees

B.3.1 GENERAL

i. Distribution map (To scale). Showing all lines up to 11KV and sub-stations belonging to the Supplier.
ii. Single line diagram of Distribution System (showing distribution lines from points of Connection with the Transmission System, 66/11KV substations, 33/11KV substations, 11/0.4KV substation, consumer bus in case of consumers fed directly from the Transmission System).
iii. Numbering and nomenclature of lines and sub-stations (Identified with feeding Grid sub-stations of the Transmission and concerned 66/11KV substation 33/11KV sub-station of Licensee).

B.3.2 CONNECTION

i. Points of Connection (Furnish details of existing arrangement of Connection).
ii. Details of metering at points of Connection.

B.3.3 LOADS

i. Connected load - Active and Reactive Load. Furnish consumer details, Number of Consumers category wise, details of loads 1 MW and above, power factor.
ii. Information on diversity of load and coincidence factor.
iii. Daily demand profile (current and forecast) on each 66/11KV substation 33/11KV sub-station.
iv. Cumulative demand profile of Distribution System (current & forecast).

APPENDIX C: OPERATIONAL PLANNING DATA

C.1 OUTAGE PLANNING DATA

REFER TO: SECTION 11 OUTAGE PLANNING

C.1.1 DEMAND ESTIMATES

For Discoms /Distribution Licensees

Item	Due date/ Time
Estimated aggregate month-wise annual sales of Energy in Million Units and peak and lean demand in MW & MVAr at each Connection point for the next financial year.	15th November of current yea
Estimated aggregate day-wise monthly sales of Energy in million Units and peak and lean demand in MW & MVAr at each Connection point for the next month.	25th of current month
15 Minute block-wise demand estimates for the day ahead.	9.00 Hours every day.

C.1.2 ESTIMATES OF LOAD SHEDDING

For Discoms/Distribution Licensee

Item	Due date/ Time
Details of discrete load blocks that may be shed to comply with instructions issued by SLDC when required, from each Connection point.	Soon after Connection is made.

C.1.3 YEAR AHEAD OUTAGE PROGRAMME(For the financial year)

C.1.3.1 GENERATION OUTAGE PROGRAMME

For SGS

Item	Due date/ Time
Identification of Generating Unit.	15^{th} November each year
MW, which will not be available as a result of Outage.	
Preferred start date and start-time or ranges of start dates and start times and period of Outage.	
If outages are required to meet statutory requirements, then the latest- date by which Outage must be taken.	

C.1.3.2 YEAR AHEAD OUTAGE PROGRAMME

(Affecting Transmission System)

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

C.1.3.3 YEAR AHEAD CPP's OUTAGE PROGRAMME

Item	Due date/ Time
MW, which will not be available as a result of Outage. Start-date and start time and period of Outage.	30th November each year

C.1.3.4 YEAR AHEAD DISCOM's OUTAGE PROGRAMME

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

C.1.3.5 STU's OVERALL OUTAGE PROGRAMME

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

C-2. GENERATION SCHEDULING DATA

REFER TO: SECTION 8 - SCHEDULE AND DESPATCH

For SGS

Item	Due date/ Time
Day ahead 15-minute block-wise MW/MVAr availability (00.00 - 24.00 Hours) of SGS.	9.00 hrs
Day ahead 15-minute block-wise MW import/export from CPP's.	9.00 hrs
Status of Generating Unit Excitation AVR in service (Yes/No).	9.00 hrs
Status of Generating Unit Speed Control System. Governor in service (Yes/No).	9.00 hrs
Spinning reserve capability (MW).	9.00 hrs
Backing down capability with/without oil support (MW).	9.00 hrs
Hydro reservoir levels and restrictions.	9.00 hrs
Generating Units 15-minute block-wise summation outputs (MW).	9.00 hrs

Day ahead 15-minute block-wise MW entitlements from Central Sector Generation Power Stations from NRLDC.	10.00 hrs

C-3 CAPABILITY DATA

REFER TO: SECTION 10

For SGS

Item	
Generators and IPPs shall submit to STU up-to-date capability curves for all Generating Units. CPPs shall submit to STU net return capability that shall be available for Export/Import from Transmission System.	On receipt of request from STU/ SLDC. On receipt of request from STU/ SLDC.

C-4 RESPONSE TO FREQUENCY CHANGE

REFER TO: SECTION 10

For SGS

Item	
Primary Response in MW at different levels of loads ranging from minimum Generation to registered capacity for frequency changes resulting in fully opening of governor valve.	On receipt of request from STU/ SLDC.
Secondary response in MW to frequency changes	On receipt of request from STU/ SLDC.

C-5 MONITORING OF GENERATION

REFER TO: SECTION 10

For SGS

Item	
SGS shall provide 15-minute block-wise generation summation to SLDC. CPPs shall provide 15-minute block-wise export/ import MW to SLDC. Logged readings of Generators to SLDC. Detailed report of Generating Unit tripping on monthly basis.	Real time basis Real time basis As required In the first week of the succeeding month

C-6 ESSENTIAL AND NON-ESSENTIAL LOAD DATA

REFER TO: SECTION 10

For SGS

Item	Due date/ Time
Schedule of essential and non-essential loads on each discrete load block for purposes of load shedding.	As soon as possible after Connection

APPENDIX D: SITE RESPONSIBILITY SCHEDULE
REFER TO: SECTION 5 CONNECTION CONDITIONS

Name of Power Station/Sub-Station:
Site Owner:
Site Manager:
Tel. Number:
Fax Number:

Item of Plant/ Apparatus	Plant Owner	Safety Respon-sibility	Control Respon-sibility	Operation Respon-sibility	Maintenance Responsibility	Remarks
……KV Switchyard						
All equipment including bus bars						

Feeders						
Generating Units						

APPENDIX E: INCIDENT REPORTING
REFER TO: SECTION 14

FIRST REPORT……

Date: ……
Time: ……

S. No.	Item	Details
1	Date and time of incident	
2	Location of incident	
3	Type of incident	
4	System parameters before the incident (Voltage, Frequency, Flows, Generation, etc.)	
5	Relay indications received and performance of protection	
6	Damage to equipment	
7	Supplies interrupted and duration, if applicable	
8	Amount of Generation lost, if applicable	
9	Possibility of alternate supply arrangement	
10	Estimate of time to return to service	
11	Cause of incident	
12	Any other relevant information and remedial action taken	
13	Recommendations for future improvement/repeat incident	
14	Name of the Organisation	

APPENDIX F : METERING CODE

APPENDIX F(1): MINIMUM ACCEPTABLE SPECIFICATIONS CURRENT TRANSFORMERS (CT) FOR METERING

Particulars	33 KV	66 KV	132 KV	220 KV
Nominal System Voltage (KV rms)	33	66	132	220
Highest System Voltage (KV rms)	36	73	145	245
Reference Standard	IS 2705 with latest amendments			
Standard CT Ratio	800-400/1-1	800-400/1-1	400/1-1	800/1-1
	600-300/1-1	600-300/1-1	200/1-1	
	400-200/1-1	400-200/1-1	100/1-1	
	300-150/1-1	300-150/1-1	50/1-1	

	100-50/1-1	100-50/1-1		
No. of Metering cores	Two			
Rated Continuous Thermal Current	120% of Rated Primary Current			
Rated Short time thermal primary current for 1 second	25	31.5	31.5	40
CT characteristics:				
Rated Primary Current (Amps)	800-400	800-400	400	800
	600-300	600-300	200	
	400-200	400-200	100	
	300-150	300-150	50	
	100-50	100-50		
Rated Secondary Current (Amps)	1	1	1	1
Accuracy Class	0.2	0.2	0.2	0.2
Maximum Instrument Security Factor (ISF)	5	5	5	5
Rated Secondary Burden (VA)	30	30	30	40
Reference Standard for insulating oil	IS 335 with latest amendments			

APPENDIX F (2): MINIMUM ACCEPTABLE SPECIFICATIONS FOR EHV CAPACITOR VOLTAGE TRANSFORMERS (CVT) FOR METERING

S. No.	Particulars	66 KV	132 KV	220 KV
1	Nominal System Voltage (KV rms)	66	132	220
2	Highest System Voltage (KV rms)	76	145	245
3	Reference Standard	IS 3156 with latest amendments		
4	Rated Capacitance (pF)	4400 pF with tolerance +10% and -5%		
5	For low voltage terminal over entire carrier frequency			
(a)	Stray Capacitance	Shall not exceed 200 pF		
(b)	Stray Conductance	Shall not exceed 20 micro siemens		
(c)	High frequency capacitance for entire carrier frequency range	Within 80% to 150% of rated capacitance		
(d)	Equivalent Series Resistance over the entire frequency range	Less than 40 ohms		
6	No. of Secondary Windings for potential measurement devices	Two	Two	Two
7	Standard Voltage Ratio			
(a)	Winding-I	$66KV/3^{1/2}$ / $110V/3^{1/2}$	$132KV/3^{1/2}$/ $110V/3^{1/2}$	$220KV/3^{1/2}$ / $110V/3^{1/2}$
(b)	Winding-II	$66KV/3^{1/2}$ / $110V/3^{1/2}$	$132KV/3^{1/2}$ / $110V/3^{1/2}$	$220KV/3^{1/2}$ / $110V/3^{1/2}$
8	Rated Secondary Burden (VA)			
(a)	Winding-I	50	50	50
(b)	Winding-II	50	50	50
9	Accuracy Class			
(a)	Winding-I	0.2		
(b)	Winding-II	0.2		

10	Rated Voltage Factor and Duration			
(a)	Winding-I	1.2 continuous and 1.5 for 30 seconds		
(b)	Winding-II	1.2 continuous and 1.5 for 30 seconds		
11	Reference Standard for insulating oil	IS 335 with latest amendments		

APPENDIX-F (3): MINIMUM ACCEPTABLE SPECIFICATIONS OF EHV POTENTIAL TRANSFORMERS FOR METERING

Particulars	66 KV	132 KV	220 KV
Nominal System Voltage (KV rms)	66	132	220
Highest System Voltage (KV rms)	73	145	245
Reference Standard	IS 3156 with latest amendments		
No. of Secondary Windings for potential measurement devices	Two	Two	Two
Standard Voltage Ratio			
(a) Winding-I	$66KV/3^{1/2}/110V/3^{1/2}$	$132KV/3^{1/2}/110V/3^{1/2}$	$220KV/3^{1/2}/110V/3^{1/2}$
(b) Winding-II	$66KV/3^{1/2}/110V/3^{1/2}$	$132KV/3^{1/2}/110V/3^{1/2}$	$220KV/3^{1/2}/110V/3^{1/2}$
Rated Secondary Burden (VA)			
(a) Winding-I	50	50	50
(b) Winding-II	50	50	50
Accuracy Class			
(a) Winding-I	0.2		
(b) Winding-II	0.2		
Rated Voltage Factor and Duration			
(a) Winding-I	1.2 continuous and 1.5 for 30 seconds		
(b) Winding-II	1.2 continuous and 1.5 for 30 seconds		
Reference Standard for insulating oil	IS 335 with latest amendments		

APPENDIX-F (4) - MINIMUM ACCEPTABLE SPECIFICATIONS OF DEDICATED HV POTENTIAL TRANSFORMERS (PT) FOR METERING

Particulars	33 KV	11 KV
Nominal System Voltage (KV rms)	33	11
Highest System Voltage (KV rms)	36	12
Reference Standard	IS 3156 with latest amendments	
No. of Secondary Windings for potential measurement devices	Two	Two
Standard Voltage Ratio (for both windings)	$33KV/3^{1/2}$ / $110V/3^{1/2}$	$11KV/3^{1/2}$ / $110V/3^{1/2}$
Rated Secondary Burden (VA) per winding	50	50
Accuracy Class (At 10% to 100% of rated VA burden)	0.2	0.2
Rated Voltage Factor and Duration	1.2 continuous and 1.5 for 30 seconds	

APPENDIX F (5): MINIMUM ACCEPTABLE SPECIFICATIONS OF CT-PT SET FOR METERING

S. No.	Particulars	33 KV
A	Specification of CT	
1	Nominal System Voltage (KV rms)	33

2	Highest System Voltage (KV rms)	36
3	Reference Standard	IS 2705 with latest amendments
4	Standard CT Ratio (Amps/Amps)	200-100/1-1 100-50/1-1
5	Rated continuous thermal current	120% of rated primary current
6	Rated short time thermal primary current for 1 second (in kA)	25
7	CT Characteristic:	
(a)	Rated Primary Current (Amps)	200-100 100-50
(b)	Rated Secondary Current (Amps)	1
(c)	Accuracy Class	0.2
(d)	Maximum Instrument Security Factor (ISF)	<10
(e)	Rated Secondary Burden (VA)	30
8	Reference Standard for insulating oil	IS 335 with latest amendments
B	**Specification of PT**	
1	Nominal System Voltage (KV rms)	33
2	Highest System Voltage (KV rms)	36
S. No.	**Particulars**	**33 KV**
3	Reference Standard	IS 3156 with latest amendments
4	No. of Secondary Windings for potential measurement devices	Two
5	Standard Voltage Ratio	$33KV/3^{1/2}$ / $110V/3^{1/2}$
6	Rated Secondary Burden (VA) per winding	50
7	Accuracy Class (At 10% to 100% of rated VA burden)	0.2
8	Rated Voltage Factor and Duration	1.2 continuous and 1.5 for 30 seconds

APPENDIX F - (6): MINIMUM ACCEPTABLE SPECIFICATION FOR VARIOUS TYPES OF METERS

S No	Particulars	Main Meters for Generating Stations*	Main Meter for Interstate lines & lines connected to Gen. Stations, CPP & Open Access Customers *	Main Meter for metering between STU & Distribution Licensees	Main Meter for Inter Discoms/Mini Hydel Stns/ Generator Aux. Trfs. /Backup Meters/ Secondary Backup**	Capacitor Bank Meter	Sub-Station Auxiliary Meter & Colony Supply Meter
	Meter Type	A	B	C	D	E	F
1	Basic Meter (Number of phases and wires)	AC Static HT TVM 3 Phase - 4 Wire type ABT compliant	AC Static HT TVM 3 Phase - 4 Wire type ABT compliant	AC Static HT TVM 3 Phase - 4 Wire TOD type having ABT programmable capability if required.	AC Static HT TVM 3 Phase - 4 Wire TOD type	AC Static HT TVM 3 Phase - 4 Wire type	AC Static/ EM LT TVM 3 Phase - 4 Wire type
					Time, date, kWh		

2	Measurand (s)	Time, date,kWh (Imp/Exp), kVArh at 103% voltage and 97% voltage & kVAh during kWh (Imp/Exp), PF (lag/lead), kW, kVA, Phase Voltage, Line current, frequency, instantaneous load in kW, anomaly Data, Power On hours.		(Imp/Exp), kVArh (lag/lead) & kVAh during kWh (Imp/Exp), PF (lag/lead), kW, kVA, Phase Voltage, Line current, frequency, instantaneous load in kW, anomaly Data, Power On hours.	Date, Time, kWh (Imp/Exp), kVArh (lag/lead), kVAh, kVA, PF (lag/lead)	kWh (Imp), kVAh, MD in kVA
3	Indian Standard or IEC to which conforming	IS:14697, IEC: 60687, CBIP Report No. 88, IS:9000 IEC: 60297-3 with latest amendments.		IS:14697, IEC: 60687, CBIP Report No. 88, IS:9000 with latest amendments.	IS:13779, IEC: 1036, IEC: 687, CBIP Report No. 88	IS:13779-1999
4 (a)	Rated Current, Amp.	3 x -/1 Amp or 3 x -/5 Amp (Ib) as per CT secondary current				-/5 Amp/ 10-60 a
4 (b)	Rated Maximum, Amp.	120 % Ib				120 % Ib for CT meter, 600% Ib for whole current meter.
4 (c)	Rated short time current, Amps.	20 Times Imax for 0.5 seconds.				
5	Rated voltage, Volts and variation.	3x110V Ph-Ph, 3x110V/√3 Ph-N, Specified variation 0.8 to 1.1 Vref, Limit Variation 0.8 to 1.1 Vref.				3x240 V Ph-N, 3x415 V Ph-Ph, Variation 0.8 to 1.1 Vref.
6	Reference frequency, Hz & variation.	50 Hz, (+/-)5%				
7 (a)	Accuracy class of meter.	0.2 S	0.2 S	0.2 S	0.5	1.0
7 (b)	Classification angle for Var meters.	Four quadrants				-
8	Whether meter is of : (a) Whole current/ CT operated (b)voltage transformer operated.	CT Operated VT Operated			CT Operated PT Operated	LT TVM may be LT CT operated/Whole Current Meter
9	Maximum demand recording period (for MDI only)	15 Min. Integration	15 Min. Integration	15 Min. Integration / TOD	15 Min. Integration / TOD	30 Min.	30 Min. for MDI
	Frequency	15 Min.	15 Min.	15 Min.			

10	Integration period	Integration	Integration	Integration / TOD	NA	NA	NA
11	Minimum starting current (As ratio of rated current)	0.1 % Ib at UPF				0.2 % Ib at UPF	0.4% Ib
12	Display of measurands	Time, Date, kWh (Imp/Exp), kVArh (lag/lead) & kVAh during kWh (Imp/Exp), PF (lag/lead), kW, kVA, Phase Voltage, Line current, frequency, instantaneous load in kW, anomaly Data, BP Wh (I/E), BP VAh (I/E), BP VA (I/E), BP PF (I/E), Power On hours.			Time, Date, kWh (Imp/Exp), kVArh (lag/lead) & kVAh during kWh (Imp/Exp), PF (lag/lead), kW, kVA, Phase Voltage, Line current, frequency, instantaneous load in kW, anomaly Data, BP kWh (I/E), BP kVAh (I/E), BP kVA (I/E), BP PF (I/E), TOD kWh (Imp/Exp),anomaly Data, Power On hours.	kWh (Imp/Exp), kVArh (lag/lead), kVAh, kVA, PF (lag/lead)	Current readings
13	Storage of measurands	Load Survey Data for 45 days with integration period of 15 minute for kW (Imp/Exp), kVA(Imp/Exp), with average frequency during 15 min block, kVAr (Imp/Exp) during low voltage (V<97%) and during high voltage (V>103%), Billing parameters for last 3 months including Power On hours and anomaly information, meter reading count, MD reset count			Load Survey Data for 45 days with integration period of 15 min. for kW (Imp/Exp) and kVA (Imp/Exp), kVAr (Imp/Exp), Billing parameters for last three (3) months including Power On Hours and anomaly information, meter reading count, MD reset count .	Load Survey Data for 45 days with integration period of 30 min. for kVAr.	kWh (Imp), kVAr, MD in kVA
14	Any other displays	Total energy i.e. Fundamental energy plus Harmonic energy, self diagnostic features.					NA
15	Counter/ display mechanism and type.	LED/ Backlit LCD type					LCD/LED/ Drum Counter
16	Import-Export measurement or reverse stop or similar feature, if any.	Yes					
17	Operation on No Load/ Anti creeping	Yes					

	device.				
18 (a)	Output device (for readings)	For testing & calibration		Yes	Yes
18 (b)	Whether remote reading feasible.	Yes		No	No
19	Meter window	Yes			
20	Meter terminals, terminal block and cover	Yes			
21	Sealing arrangement	Yes			
22	Protection features	As per relevant standatds mentioned in S.No. 3 and ISI2063/IEC 60529.			
(a)	Heat & Fire				
(b)	Shock & vibration				
(c)	Dust & Water [IP class]				
(d)	Electro magnetic fields				
(e)	Radio interference				
(f)	Electro static fields				
(g)	Meter reading jumps	Not Applicable			
23 (a)	Tamper prevention / recording for Meter	Tamper and anomaly detection features like missing potential, CT polarity reversal, Power ON/OFF event, current and voltage unbalance shall be recorded.			Tamper and anomaly detection features like missing potential, CT polarity reversal, Power ON/OFF event, shall be recorded.
23 (b)	Tamper prevention / recording for Counter	Not Applicable			As per IS:13779-1999
24	Any other feature / requirement.	a) CT PT error compensation, frequency based information for displayed measurands. b)Communication port: One RS232 optical port for local meter reading. One RS232 galvanically isolated port for	Communication port: One RS232 optical port for local meter reading. One RS232 galvanically	Communication port: One communication port RS 232 optical port for local meter	Communication port: One communication port RS 232 optical port for local meter	NA

		remote meter reading. c) Automatic CT shorting d) Auxiliary power for meter from DC supply and AC auxiliary supply of sub-station	isolated port for remote meter reading.	reading through CMRI	reading through CMRI	
25	Common Meter Reading Instrument (CMRI)	As per CBIP report No. 111, IP67, IEC 529, IS 12063, CISPAR22 , IEC 1000				
26	Base Computer	a) Fourth generation or above processor with preloaded windows 98 or higher operating system with all latest accessories. b) Software shall make available all the data in ASCII formats.			NA	NA
27	Modem	Shall conform to British Approval Board for Telecommunications (BABT) standard for data communication and to V.22 data transmission standard recommended by Comite Consultatif International Telephonique et Telegraphic (CCITT).			NA	NA

Note : * Specification of the secondary back up of generator & Interstate line shall be ABT compliant and as per Meter Type A & B.

** Specification of back up/ secondary back up are for STU -Discom meters.