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অসম ৰাজপত্ৰ

সত্যমেব জয়তে

THE ASSAM GAZETTE

অসাধাৰণ

EXTRAORDINARY

প্ৰাপ্ত কৰ্ত্তৃত্বৰ দ্বাৰা প্ৰকাশিত

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GOVERNMENT OF ASSAM

ORDERS BY THE GOVERNOR

ASSAM ELECTRICITY REGULATORY COMMISSION

NOTIFICATION

The 5th September, 2018

Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2018.

No. AERC.642/2017/244.- In exercise of powers conferred under Sections 181 of the Electricity Act, 2003, read with Section 86 (1) (h) and all powers enabling it in that behalf, the Assam Electricity Regulatory Commission hereby frames the following Regulations to replace and repeal the AERC (Electricity Grid Code) Regulations, 2004, namely;

1) **Short title, commencement and interpretation:-**

a) These Regulations may be called the Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2018.

b) These Regulations shall be applicable to all intra-State Transmission System participants, including

i. The State Transmission Utility and Transmission Licensees

ii. Generating Stations including Captive and RE Generators, connected to intra State Transmission System

iii. Distribution Licensees connected with intra State Transmission System

iv. EHV Consumers of Distribution Licensee directly connected to intra State Transmission System

v. Open access customers availing open access on intra state Transmission system

vi. Any other person connected to and/or user of intra state Transmission system, not specified above.

c) These Regulations shall extend to the whole State of Assam.

d) These Regulations shall come into force with effect from the date of its publication in Assam Gazette.

PART-I

GENERAL CODE

CHAPTER-1: GENERAL

1.1. INTRODUCTION

The Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2018 (hereinafter referred as State Grid Code or SGC) lays down the rules, guidelines and standards to be followed by various person and participants in the Intra-State transmission system (IaSTS) to plan, develop, maintain and operate the intra-State transmission system of Assam, in most efficient, reliable, economic and secure manner, while facilitating a healthy competition in the generation and supply of electricity.

1.2. OBJECTIVES

The State Grid Code brings together a single set of technical and commercial rules, encompassing all the Utilities connected to/or using the intra-State transmission system (IaSTS) and provides the following:

a) Documentation of the principles and procedures which define the relationship between the various Users of the intra-State transmission system (IaSTS), as well as the State Load Despatch Centre, concerned RLDC & NLDC.

b) Facilitation of the operation, maintenance, development and planning of economic and reliable State Grid.

c) Facilitation for beneficial trading of electricity by defining a common basis of operation of the IaSTS, applicable to all the Users of the IaSTS

d) Facilitation of the development of Renewable Energy sources by specifying the technical and commercial aspects for integration of these sources into the Grid.

1.3. SCOPE

a) All users such as Generating Companies including Captive Power Plants & RE Generators, Distribution Companies, Open Access Customers, EHV consumers etc. that are connected 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.

b) This code shall also apply to STU, Transmission Licensee and SLDC.

c) STU, SLDC and all Users shall abide by this code to the extent it applies to them

d) This State Grid Code shall apply for the Intra-State transmission of electricity.

e) This State Grid Code shall not affect the obligations of the STU, SLDC and Users as laid down under the Indian Electricity Grid Code notified by CERC, and/or the Electricity

Act, 2003 and rules and regulations made there under.

f) In case of any inconsistency between CEA Grid Standards and the State Grid Code, the provision of Grid Standards shall prevail.

1.4. STRUCTURE OF GRID CODE

The Grid Code has been divided into following parts:

I. General Code

The General Code is intended to ensure that all other sections of the Grid Code work together in the management of the Grid Code and establishment of a procedure for review of Grid Code and the modifications needed from time to time.

II. Planning Code

Planning Code includes sections on:

a) System Planning specifying the procedures to be applied by STU in the planning and development of the transmission system and by other Users connected or seeking Connection to the STU's transmission system. This section deals with procedure to be followed by STU in the development of the EHV transmission system in the long term, taking into account the requirements for new connection of generation and demand and the transmission n system performance standards issued by the Commission.

b) Connection Issues specifying the technical requirements and standards to be complied with by STU and other Users connected or seeking connection to the intra-state transmission system.

III. Load Despatch & System Operation Code

Load Despatch & System Operation Code includes sections on:

a) System Operation: specifying the conditions under which SLDC shall operate the intra-state transmission system, the Generating Companies shall operate their plants and the Distribution Licensees shall operate their Distribution Systems in so far as necessary to protect the security and quality of supply and safe operation of the State Grid by SLDC under both normal and abnormal operating conditions.

b) Schedule and Despatch: specifying the procedures relating to the scheduling and despatch of sellers/ Generating Units and drawal by buyers/Distribution Licensees to meet State demand and Drawal allocation.

c) Outage Planning: specifying the procedures relating to the co-ordination of outages for scheduled maintenance of the intra-state transmission system, generating units and distribution system operating in the State Grid.

IV. Protection Code

Protection Code specifies the requirement and co-ordination responsibility and optimum standards of protection that are required to be installed by Users of the State Grid.

V. Metering Code

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

VI. Data Registration

This contains the details of all the data required by STU / SLDC, which is to be provided by the Users and viceversa.

1.5. INTERPRETATION

In the interpretation of this Code, unless the context otherwise requires:

(i) words in the singular or plural term, as the case may be, shall also be deemed to include the plural or the singular term, respectively;

(ii) the headings are inserted for convenience and may not be taken into account for the purpose of interpretation of this Grid Code;

(iii) references to the statutes, regulations or guidelines shall be construed as including all statutory provisions consolidating, amending or replacing such statutes, regulations or guidelines, as the case may be.

1.6. GENERAL REQUIREMENTS

The 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 recognize that the Grid Code cannot predict and address all possible operational conditions.

Users must therefore understand and accept that STU in such unforeseen circumstances may be required to act decisively to discharge its obligations as STU. SSGS and Distribution Licensees shall provide such reasonable co-operation and assistance as STU may request in such circumstances.

1.7. CODE RESPONSIBILITIES

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

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

1.8. CONFIDENTIALITY

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

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

1.9. DISPUTE SETTLEMENT PROCEDURES

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

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

1.10. COMMUNICATION BETWEEN STU AND USERS

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

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

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

1.11. PARTIAL INVALIDITY

If any provision or part of a provision of the Grid Code should become or be declared unlawful for any reason, the validity of all remaining provisions or parts of provisions, of the Grid Code shall not be affected.

1.12. 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.

1.13. CONSISTENCY BETWEEN GRID CODE AND EXISTING CONNECTION AGREEMENTS

a. This Grid Code applies to:

   (i) All connection agreements made before and after the Code commencement date;

   (ii) All requests to establish connection or modify an existing connection after the Code commencement date.

b. This Grid Code is neither intended to, nor is it to be read or construed as having the effect of:

(i) altering any of the terms of an existing *connection agreement*; or

(ii) altering the contractual rights or obligations of any of the parties under the existing *connection agreement* as between those parties; or

(iii) relieving the parties under any such *connection agreement* of their contractual obligations under such an *agreement*; or

(iv) Notwithstanding the provisions of sub-clauses (i) through (iii) above, if any obligation; imposed or right conferred on a User or Transmission Licensee by this Code is inconsistent with the terms of an existing connection agreement to which this Code applies and the application of the inconsistent terms of the connection agreement would adversely affect the quality or security of network service to other intra State transmission system Users, the parties to the connection agreement must observe the provisions of this Code will prevail over the connection agreement to the extent of the inconsistency.

1.14. COMPATIBILITY WITH INDIAN ELECTRICITY GRID CODE

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

The Grid Code shall be reviewed and revised to make it consistent/ compatible in accordance with National Grid Code having regard to Grid Standards as and when specified by the Central Electricity Regulatory Commission under section 79,(1), (h) of the Electricity Act, 2003.

CHAPTER 2: DEFINITIONS

2.1.	**Act**	"Act" means The Electricity Act' 2003 (Central Act No. 36 of 2003)
2.2.	**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
2.3.	**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.
2.4.	**AERC**	AERC means "Assam Electricity Regulatory Commission", also referred as the "Commission"
2.5.	**Agency**	Agency means the utilities that utilize the State Grid
2.6.	**Ancillary Services**	Ancillary Services means, in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, eg. Active power support for full load following, reactive power support, black start.
2.7.	**Apparatus**	Electrical apparatus and includes all machines, fittings, accessories and appliances which consumes or produce electricity.
2.8.	**Apparent Power**	Apparent Power means the product of voltage and current measured in units of volt amperes and standard multiples thereof.
2.9.	**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.
2.10	**Appendix**	An Appendix to a section of the Grid Code.
2.11	**Area of Supply**	Area within which a distribution licensee is authorised by his license to supply electricity.
2.12	**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.
2.13	**Auxiliaries**	All the plant and machinery required for the Generating Unit's functional operation that do not form part of generating unit.
2.14	**Authority**	Authority means the Central Electricity Authority (CEA) as defined in the Act
2.15	**Available Transfer Capability(ATC)**	ATC refers to the transfer capability of inter-control area transmission system available for scheduling commercial

		transactions (through long term access, medium term open access and short term open access) in a specific direction, taking into account the network security. Mathematically, ATC is the total transfer capability less transmission reliability margin.
2.16	**Availability**	Availability shall have the same meaning as defined in the AERC (Multi Year Tariff) Regulations, 2018 and its subsequent amendments.
2.17	**ABT**	ABT means Availability Based Tariff
2.18	**Backing Down**	SLDC instructions or NERLDC instructions conveyed through SLDC for reduction of generation from generating unit under abnormal conditions such as high frequency, low system demand or network constraints.
2.19	**Black Start Procedure**	Black Start Procedure means "the process of recovery from a total or partial blackout of the Regional/State Grid"
2.20	**Bilateral Transaction**	Bilateral Transaction means a transaction for exchange of energy(MWH) between a specified buyer and a specified seller, directly or through a trading licensee or discovered at Power Exchange through anonymous bidding from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for any time period during a specified period.
2.21	**Breakdown**	Breakdown means an occurrence relating to equipment of supply system which prevents its normal functioning.
2.22	**Bulk Consumer**	Bulk consumer refers to any consumer who avails of supply at voltage of 33kV or above.
2.23	**Buyer**	Buyer means a person, including beneficiary, purchasing electricity through a transaction scheduled in accordance with the regulations applicable for short term open access, medium term open access and long term open access.
2.24	**Captive Power Plant / CPP**	For the purpose of Grid Code, a Power Station that is primarily operated to meet a captive demand and is connected to State Grid but not supplying power to the Grid under normal circumstances.
2.25	**CBIP**	Central Board of Irrigation & Power.
2.26	**Central Generating Station**	Central Generating Station means the Generating Stations owned by the companies owned or controlled by the Central Government.
2.27	**Central Transmission Utility(CTU)**	CTU means any Government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act.

2.28	**Collective Transaction**	Collective Transaction means a set of transactions discovered in power exchange through anonymous, simultaneous competitive bidding by buyers and sellers.
2.29	**Congestion**	Congestion means a situation where the demand for transmission capacity exceeds the available transfer capacity.
2.30	**Connection Agreement**	Connection Agreement means an agreement between STU and a User setting out the terms relating to the Connection to and/or use of the State Transmission System.
2.31	**Connection Conditions**	Connection Conditions means the technical conditions to be complied with by any User having a Connection to the State Transmission System as laid down in: "Connection Conditions" of the Grid Code.
2.32	**Connection Point**	Connection point means a point at which a plant and /or Apparatus connects to the Transmission/Distribution system.
2.33	**Consumer**	Consumer will have the same meaning as defined in the Act.
2.34	**Control Area**	Control Area refers to an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and /or load to maintain its interchange schedule with other control areas whenever required and contributes to frequency regulation of the synchronously operating system.
2.35	**Connectivity**	Connectivity means the state of getting connected to the intra-state transmission system by a generating station, including a captive generating plant, a bulk consumer or an intra-state transmission licensee.
2.36	**COD or Date of Commercial Operation**	COD or Date of Commercial Operation will have the meaning as defined under the AERC (Multi Year Tariff) Regulations, 2018
2.37	**DCC**	DCC means Distribution Control Centre as specified in Chapter 3 of this Code**.**
2.38	**Demand**	The demand of active power MW and reactive power MVAR of electricity unless otherwise stated.
2.39	**Demand response**	Demand response means reduction in electricity usage by end customers from their normal consumption pattern, manually or automatically. The same is done in response to high DSM charges being incurred by the State due to overdrawal at low frequency, or in response to congestion charges being incurred for creating transmission congestion, or for alleviating a system

		contingency, for which such consumers could be given a financial incentive or lower tariff.
2.40	**Despatch Schedule**	Despatch Schedule means the ex-power plant net MW and MWH output of a generating station, scheduled to be exported to the Grid from time to time.
2.41	**Deviation**	Deviation in a time block for a seller means its total actual injection minus its total schedule generation. Deviation for a buyer means its total actual drawal minus its total scheduled drawl.
2.42	**df/dt Relay**	A relay which operates when the rate of change of system frequency (over time) goes higher than a specified limit and initiates load shedding
2.43	**Disconnection**	The act of physically separating a User's or EHV Consumer's electrical equipment from the State Transmission System.
2.44	**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.
2.45	**Disturbance Recorder(DR)**	Disturbance recorder or DR means a device provided to record the behavior of the pre-selected digital and analog values of the system parameters during an event.
2.46	**Drawal Schedule**	Drawal Schedule means the Ex-power plant MW that a Distribution Licensee or Open Access user is scheduled to receive from SSGS/ISGS including bilateral transaction from time to time.
2.47	**DPR**	DPR means Distance Protection Relay
2.48	**Event**	"Event" means an unscheduled or unplanned occurrence in the intra-State transmission system including faults, incidents and breakdowns;
2.49	**Event logging facilities**	Event logging facilities means a device provided to record the chronological sequence of operations, of the relays and other equipment.
2.50	**Ex Power Plant**	Ex Power Plant means net MW/MWH output of a generating station, after deducting auxiliary consumption and transformation losses.
2.51	**Extra High Voltage (EHV)**	Extra High Voltage means nominal voltage levels of higher than 33 kV.
2.52	**EHV Consumer**	A person to whom electricity is provided and who has a dedicated supply at 66 kV or above.
2.53	**Fault Locator**	Fault locator means a device provided at the end of a transmission line to measure/indicate the distance at which a line fault may have occurred.

2.54	**Flexible AC transmission system(FACTS)**	FACTS is a power electronics based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.
2.55	**Forced Outage**	Forced Outage means an outage of a Generating Unit or a transmission facility due to a fault or other reasons which has not been planned.
2.56	**Force Majeure**	Force Majeure refers to any event which is beyond the control of the persons involved, which they could not foresee or with a reasonable amount of diligence, could not have foreseen or which could not be prevented and which substantially affects the performance by person such being the following including but not limited to :- a) Acts of God, natural phenomena, floods, droughts, earthquakes and epidemics; b) Riot or civil commotion; c) Grid failure not attributable to a person.
2.57	**Generating Unit**	Generating Unit means an electrical Generating Unit coupled to a turbine within a Power Station together with all Plant and Apparatus at that Power Station which relates exclusively to the operation of that turbo-generator.
2.58	**Grid**	The combination of the State Transmission System, Distribution System and Power Stations.
2.59	**Grid Code / Code**	"Grid Code" also referred Assam State Grid Code /State Grid Code means the set of principles and guidelines prepared in accordance with the terms of section 86 (1) (h) of the Electricity Act 2003.
2.60	**Grid Standards**	Grid Standards means the standards specified by the Authority under clause (d) of the Section 73 of the Act.
2.61	**Grid Contingencies**	Grid Contingencies means abnormal operating conditions brought out by tripping of generating units, transmission lines, transformers or abrupt load changes or by a combination of the above leading to abnormal voltage and/or frequency excursions and/or overloading of network equipment.
2.62	**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.

2.63	**Grid Code Management Committee (GCMC)**	GCMC means the Committee set up under "Management of Grid Code" of the Grid Code.
2.64	**IE Rules**	IE Rules means Indian Electricity Rules 1956 and subsequent amendments.
2.65	**Independent Power Produce (IPP)**	Independent Power Producer means a Power Station within the State, owned by a Generator who is not part of the State Generating Company (APGCL in case of Assam), STU or Central Sector Generation and is not classified as a CPP.
2.66	**Indian Electricity Grid Code (IEGC)**	IEGC means the set of principles and guidelines prepared in accordance with the terms of section 79 (1) (h) of the Electricity Act 2003 by the CERC.
2.67	**Inter Connecting Transformer (ICT)**	ICT means transformer connecting EHV lines of different voltage levels.
2.68	**Inter-State Generating Station (ISGS)**	ISGS means a Central owned/UMPP/other generating stations in which two or more than two states have a share and whose scheduling is to be coordinated by the RLDC.
2.69	**Intra-State Generating Station (IaSGS)**	IaSGS means a State owned/UMPP/other generating stations in which only the state have share and whose scheduling is to be coordinated by the SLDC.
2.70	**Inter-State Transmission System (ISTS)**	ISTS means any system for conveyance of energy by means of a main transmission line from territory of one state to another state and includes: The conveyance of energy across the territory of an intervening state as well as conveyance within the state which is incidental to such inter-state transmission of energy. The transmission of energy 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.
2.71	**Licensee**	Licensee means a person who has been granted a license under section 14 of the Act.
2.72	**LILO**	LILO means loop in loop out.
2.73	**LBB**	LBB means local breaker back-up.
2.74	**Load**	Load means MW/MWH/MVAR consumed by a utility/installation/appratus.
2.75	**Load Crash**	Load Crash means sudden or rapid reduction of electrical load connected to a system that could be caused due to tripping of major transmission line(s), feeder(s), power transformer(s) or natural causes like rain etc.

2.76	**Maximum Continuous Rating (MCR)**	MCR means the normal rated full load MW output capacity of a Generating Unit, which can be sustained on a continuous basis at specified conditions.
2.77	**NTPC**	National Thermal Power Corporation Limited.
2.78	**National Grid**	National Grid means the entire inter-connected electric power network of the country.
2.79	**Net drawal schedule**	Net drawal schedule means the drawal schedule of a Regional entity after deducting the apportioned transmission losses(estimated).
2.80	**NLDC**	NLDC means National Load Despatch Centre established under sub-section (1) of section 26 of the Act.
2.81	**North-East Region / Region**	Region comprising of the States and Union Territory of Arunachal Pradesh Assam, Meghalaya, Manipur, Mizoram, Nagaland and Tripura.
2.82	**North-East Regional Grid System**	North-East Regional Grid System means power systems of SEBs/ Utilities/ IPP/ CPPs of the States of the North-Eastern Region and of NTPC & PGCIL having integrated operation.
2.83	**NERPC**	North Eastern Regional Power Committee.
2.84	**NERLDC**	North East Regional Load Dispatch Centre.
2.85	**Operation**	Operation means a scheduled or planned action relating to the operation of a system.
2.86	**Operating range**	Operating range means the operating range of frequency and voltage as specified under the operating code.
2.87	**Operation co-ordination sub-committee(OCC)**	OCC means a sub-committee of RPC with members from all the regional entities which decides the operational aspects of the regional Grid.
2.88	**Open Access**	Open Access carries the same meaning as defined under the Act
2.89	**Open Access Customer**	Open Access Customer will have the same meaning as defined under the AERC (Terms and Conditions of Open Access) Regulations, 2018
2.90	**Outage**	Outage in relation to a Generator/ Transmission/ Distribution facility, means, an interruption of power supply whether manually or by protective relays in connection with the repair or maintenance of the SSGS/Transmission facility or resulting from a

		breakdown or failure of the Transmission /Distribution facility/SSGS unit or defect in its Auxiliary system.
2.91	**Peak Period**	Peak Period means that period in a day when electrical demand is at its highest.
2.92	**Planned Outage**	Planned Outage means an Outage in relation to a SSGS 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.
2.93	**Power Station**	Power Station means an installation of one or more Generating Units (even when sited separately) owned and/or operated by the same SSGS and which may reasonably be considered as being managed as a single integrated generating complex.
2.94	**Power System**	"Power System" means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely: generating stations; transmission or main transmission lines; sub-stations; tie-lines; load despatch activities; mains or distribution mains; electric supply lines; overhead lines; service lines; works;
2.95	**Power Grid/ PGCIL**	The Power Grid Corporation of India Limited.
2.96	**Protection co-ordination sub-committee(PCC)**	PCC means a sub-committee of RPC with members from all the regional entities which decides on the protection aspects of the regional Grid.
2.97	**Pool account**	Pool account means regional /state account for payments regarding deviation settlement or reactive energy exchanges, as the case may be.
2.98	**PTW (Permit to Work)**	PTW means 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.
2.99	**Rotational Load Shedding**	Rotational Load Shedding means 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.
2.100	**Regional Transmission System**	The combination of EHV electric lines and electrical equipment owned or operated by Power Grid / utilities.
2.101	**Reactor**	Reactor means an electrical facility specifically designed to absorb reactive power.
2.102	**Regional entity**	Regional entity means such persons who are in the RLDC control area and whose metering and energy accounting is done at the regional level.

2.103	**Regional Power Committee (RPC)**	RPC means a committee established by resolution by the Central Govt. for a specific region for facilitating the integrated operation of the power systems in that region.
2.104	**Regional energy accounting**	Regional energy accounting means a regional energy account prepared on monthly basis by the RPC Secretariat for the billing and settlement of capacity charge, energy charge and transmission charge.
2.105	**RLDC**	RLDC means the Regional Load Despatch Centre as created under the Section 27 of the Act.
2.106	**Seller**	Seller means a person, including a generating station, supplying electricity through a transaction schedule in accordance with the regulations applicable for short term open access, medium term open access and long term open access.
2.107	**Shut Down**	Shut Down means 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.
2.108	**Spinning Reserve**	Spinning Reserve means the capacities which are provided by devices including generating station or units thereof synchronized to the grid and which can be activated on the direction of the system operator and effect the change in active power.
2.109	**SPS**	SPS means special protection scheme.
2.110	**State**	State means The State of Assam.
2.111	**State Entity**	State entity means an entity which is in the SLDC's control area and whose metering and energy accounting is done at the State level.
2.112	**State Load Despatch Centre (SLDC)**	SLDC means the State Load Despatch Centre of Assam created under the Section 31 of the Act, presently having its control room at Kahlipara, is the apex body to ensure integrated operations of the power system in the state.
2.113	**State Sector Generating Station (SSGS)**	SSGS means any power station within the State, except the Inter-State Generating Station (ISGS) located within the State.
2.114	**State Transmission System (STS)**	STS means the system of EHV electric lines and electrical equipment operated and/or maintained by STU or any Transmission Licensee for the purpose of the transmission of electricity between Power Stations, External Interconnections and the Distribution System.
2.115	**State Transmission Utility (STU)**	"State Transmission Utility" means the Government Company specified as such by the State Government under sub-section (1) of the section 39 of the Act. Assam Electricity Grid Corporation Limited

		(AEGCL) has been notified as State Transmission Utility under section 39 of the Act by GoA.
2.116	**SCADA**	SCADA means Supervisory Control and Data Acquisition
2.117	**Synchronised**	"Synchronized" means the state where connected alternating current systems, machines, or a combination of these operate at the same frequency, and where the phase angle displacements between voltages in them are constant or vary about a steady and stable average value.
2.118	**SVC**	SVC means Static VAR compensator, i.e. an electrical facility designed for the purpose of generating or absorbing reactive power.
2.119	**Total transfer capacity (TTC)**	TTC means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency.
2.120	**User**	A person such as Generating Stations within Assam including captive Generating plants, Transmission Licensees or Distribution Licensees, within Assam and open access customers, who use the State Transmission System and who must comply with the provisions of the Grid Code.
2.121	**Unscheduled Generation**	Unscheduled Generation means any generation that is in violation of SLDC / NERLDC instructions and parameters described in relevant sections of the Grid Code.
2.122	**VAR**	VAR means Volt Ampere Reactive
2.123	**WAMS**	WAMS means Wide Area Monitoring System, refers to a system comprising of phasor measurement units (PMUs) and the integrated data communication system for collecting various power system including the amplitude and phase angle of the various power system parameters like voltage, power flow, frequency from multiple locations on the power system and extracts the dynamic characteristics of the system from the data easily and with a high degree of accuracy.

CHAPTER 3: MANAGEMENT OF THE GRIDCODE

3.1. Introduction

3.1.1. The State Grid Code (SGC) shall be specified by the Commission. Any amendment to SGC shall also be specified by the Commission only.

3.1.2. State Grid Code shall be reviewed by the Grid Code Management Committee at least once in every twelve (12) months or as may be directed by the Commission.

3.1.3. Upon completion of such review, the Grid Code Management Committee shall send a report to the State Transmission Utility providing information regarding:

(a) outcome of the review; and

(b) Any proposed revisions to the State Grid Code.

3.1.4. The State Transmission Utility shall send the report, referred in sub-Regulation (3) of this Regulation to the Commission.

3.1.5. The SGC and its amendments shall be finalized and notified adopting the prescribed procedure followed for Regulations issued by the Commission.

3.1.6. The requests for amendments to/modifications in the SGC and for removal of difficulties shall be addressed to Secretary to the Commission, for periodic consideration, consultation and disposal.

3.1.7. Any dispute or query regarding interpretation of SGC may be addressed to Secretary to the Commission and clarification issued by the Commission shall be taken as final and binding on all concerned.

3.2 Objective

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

3.3 Roles and Responsibilities:

3.3.1 SLDC :

The SLDC shall have the following roles and responsibilities:

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

   a. The State Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in a State.

b. The State Load Despatch Centre shall -

1. be responsible for optimum scheduling and despatch of electricity within a State, in accordance with the contracts entered into with the licensees or the generating companies operating in that State;
2. monitor grid operations;
3. keep accounts of the quantity of electricity transmitted through the State grid;
4. exercise supervision and control over the intra-State transmission system; and be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the State Grid Code.

II. In accordance with section 33 of the Electricity Act,2003, the SLDC in a State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in that State.

Every licensee, generating company, generating station, sub-station and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Depatch Centre under sub- section (1) of Section 33 of the Electricity Act,2003.

III. The State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre. .

IV. In case of inter-state bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the Central Electricity Regulatory Commission (Open Access in inter-state Transmission) Regulations,2008 , amended from time to time.

V. SLDC shall be manned by qualified and experienced engineers and professionals who are well acquainted with the State Transmission System and grid operations.

VI. Periodical Training shall be imparted to the personnel of the SLDC to update their skills in order to enable them to discharge their functions stipulated under the The Act.

VII. If any licensee, generating company or any other person fails to comply with the directions issued by SLDC, he shall be liable to penalty as stipulated under the The Act.

VIII. Operation of State DSM pool account, State Reactive Energy account, State Congestion Charge Account, State Transmission Deviation Accounts and other functions as directed by the Commission.

3.3.2 STU:

The STU shall have the following roles and responsibilities:

I. Section 39 of the Electricity Act, 2003, outlines that the functions of the State

Transmission Utility (STU) shall be –

a. to undertake transmission of electricity through intra-State transmission system;
b. to discharge all functions of planning and co-ordination relating to intra-state transmission system with-
    1. Central Transmission Utility;
    2. State Governments;
    3. Generating companies;
    4. Regional Power Committees;
    5. Authority;
    6. Licensees;
    7. any other person notified by the State in this behalf;
c. to ensure development of an efficient, co-ordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centers;
d. to provide non-discriminatory open access to its transmission system for use by -
    1. any licensee or generating company on payment of the transmission charges; or
    2. any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42 of the Act, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission .

II. Until a Government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre.

3.3.3 DCC (Distribution Control Centre):

Distribution Licensees operating in the State shall establish their DCC to carry out the operating directives of SLDC and assist SLDC for safe and integrated operation of the concerned distribution network. DCC must have a 24 x 7 control room with adequate numbers of qualified manpower.DCC shall be responsible for:

I. Data acquisition and transfer to SLDC
II. Supervisory control of load in their respective area
III. Assist SLDC to ensure safe and integrated operation of the power system of the State;
IV. Assist SLDC for monitoring grid operations;
V. Carry out the real-time instructions of SLDC for safe and integrated operation of the State grid.
VI. Maintain the drawal and/ or injection schedule as finalized by SLDC;
VII. DCC shall comply with all the directives given by SLDC and provide all relevant information as and when required by the SLDC.

3.4 Grid Code Management Committee (GCMC):

3.4.1 A **Grid Code Management Committee** shall be constituted by the State Transmission Utility with the consent of the commission within thirty (30) days from the date of notification of these Regulations.

3.4.2 The Grid Code Management Committee shall be responsible for the following matters, namely-

I. facilitating the implementation of these Regulations and the rules and procedures developed under the provisions of these Regulations;

II. assessing and recommending remedial measures for issues that might arise during the course of implementation of provisions of these Regulations and the rules and procedures developed under the provisions of these Regulations;

III. to assess and advise to the commission, the necessary amendments/changes required to be brought, in these regulations for smooth operation of the power sector and in the interest of overall compliance to the provisions of the Electricity Act 03 and;

IV. to review & ensure compliance of roles & responsibilities of various agencies/entities as specified in the Code

V. To Review and to take follow up action on the recommendations of the functional committees formed under this Code.

VI. such other matters as may be directed by the Commission from time to time.

3.4.3 The Grid Code Management Committee shall comprise of the following members & Chairman:

I. Managing Director of State Transmission Utility shall be the Chairperson

II. Chief Executive of the SLDC shall be the Convenor

III. One member from State Transmission Utility;

IV. One member to represent state generating companies

V. One member from each class of generating companies in the State, other than state generating companies.

VI. One member to represent the Transmission Licensees in the State, other than the State Transmission Utility;

VII. One member each to represent the state-owned Distribution Licensees in the State;

VIII. One member to represent the privately-owned Distribution Licensees, if any

IX. One member to represent the Electricity Traders in the State;

X. One member to represent the Open Access Customers

XI. One member to represent the North Eastern Regional Load Despatch Centre; and

XII. One member to represent the North Eastern Regional Power Committee

XIII. Such other persons as may be nominated by the Commission.

3.4.4 Provided further that the State Transmission Utility shall, in coordination with State Load Despatch Centre, provide necessary support to facilitate smooth functioning of the Grid Code Management Committee. The members of the GCMC shall be selected as follows:

I. The member referred to in clause 3.4.3 (II) above shall be the head of State Load Despatch Centre;

II. the concerned technical person of the State Transmission Utility, having the responsibility of looking after Operation & Maintenance, System Studies & System Protection activities of State Transmission Utility shall be the member referred to in clause 3.4.3 (III) of the above Regulation;

III. the members referred to in clauses other than 3.4.3 (I) & (I) above, shall be nominated by their respective organizations, which organizations will be selected in rotation from among all such organizations in the State.

IV. The term of each such member, selected in rotation, shall be one (1) year. Provided that the members nominated by each of the organization to the above Committee shall be holding a senior position in their respective organization.

3.4.5 The Rules to be followed by the Committee in conducting their business shall be formulated by the Committee themselves and shall be approved by the AERC. The Committee will meet at least once in Six months.

3.4.6 Functional Committees under Grid Code Management Committee

I. The SLDC is responsible for servicing/implementation of Grid Code, whereas the Grid Code Management Committee shall be responsible for management of Grid Code for any changes, modifications in the Grid Code. The Grid Code Management Committee shall constitute following committees for implementation of the Grid Code:

(a) System Operation Code: State Operation and Co-ordination Committee (OCC)

(b) Protection Code: State Protection Co-ordination Committee (PCC)

(c) Transmission Metering Code: State Transmission Metering Committee (TMC)

II. The Grid Code Management Committee shall nominate the members of the functional committees. Chairman and Member Secretary of the functional committees shall be from the STU.

III. However, STU can formulate any other operational committee as it deems fit for the implementation of the Grid Code.

IV. Formation and roles of various committees to be formed under clause (I) above:

(a) State Operation and Co-ordination Committee(SOCC)

Operation and Co-ordination Committee shall coordinate the implementation of Load Despatch & System Operation Code to ensure that respective Generators and Distribution Licensees using Intra State transmission system discharge their obligations under the Grid Code.

OCC shall comprise of a senior representative from each Users of Intra State transmission system, as members, to be appointed by the Grid Code Management Committee, which shall meet once every three months and deliberate on all technical and operational aspects of Load Despatch and System Operation and shall give their recommendations to the Grid Code Management Committee. It shall conduct the following functions.

The rules to be followed by the committee in conducting their business shall be formulated by the Committee itself and shall be approved by Grid Code Management Committee. The functions, inter alia, are:

1. Review of existing interconnection and equipment for alteration, if necessary, so as to comply with the Connection Conditions provided for in the Code.
2. Deliberation on connectivity criterion for voltage un-balance as specified schedule-II of Transmission Performance Standards and taking remedial measure for cases failing to meet such criterion.
3. Review the load forecast and the methodology and assumptions made by each of the Distribution Licensees.
4. Review the load shedding through under frequency relays.
5. Transmission system planning coordination for the State as a whole.
6. Review and finalize the proposals identified on the basis of planning studies.

(b) State Protection Co-ordination Committee (SPCC)

Protection Co-ordination Committee shall coordinate the implementation of Protection Code, as specified in Part-IV of the Code, to ensure that respective Users using Intra State transmission system discharge their obligations under the Protection code.

Protection Co-ordination Committee shall consist of following members:

(i) Chairman who is an officer designated by STU.

(ii) Member Secretary who is also an officer from STU.

(iii) One representative from APGCL

(iv) One representative from each Distribution Licensees.

(v) One representative from SLDC.

The rules to be followed by the Protection Co-ordination Committee in conducting their business shall be formulated by the committee itself and shall be approved by Grid Code Management Committee (GCMC). The committee shall meet at least once in three months and conduct, inter alia, the following functions.

1. To keep Protection Code and its implementation under scrutiny & review.
2. To consider all requests for amendment to the Protection code which anyuser makes.
3. To publish recommendations for changes to the Protection code together with the reason for the change and any objection if applicable.
4. To issue guidance on the interpretation & implementation of the Protection code.
5. To deliberate and decide various protection settings testing procedure and periodicity.
6. To review and specify the optimum protection requirements for User's system connected to the Intra State transmission system.
7. To 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.
8. Preparation and finalisation of technical requirement of various protections, Disturbance recorders, Event Loggers.
9. Along with under frequency load-shedding schemes the load-shedding through df/dt relay should also be included in the sentence.

10. The DR (Disturbance Recorder) of the Numerical Relays/other Disturbance Recorder should be furnished by the STU to the SLDC within 24 hour of the occurrence of the disturbance.

(c) State Transmission Metering Committee(STMC)

Transmission Metering Committee shall be constituted as per the provisions of the Metering Code as specified in Part-V of the Act.

The rules to be followed by the Metering Committee in conducting their business shall be formulated by the Metering Committee itself and shall be approved by Grid Code Management Committee. The Metering Committee shall meet at least once in three months.

3.5 Non-Compliance & Relaxation

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

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

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

3.5.4 Relaxation, if any, for any particular section or chapter of the Grid Code shall be with the express permission of the Commission for a specified time. Relaxation of any requirement of the 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 in the required time-scale. Failure to comply with the permitted time-frame of relaxation, by any User, shall carry a financial penalty, as may be decided by the Commission, while allowing the relaxation.

PART-II

PLANNING CODE

CHAPTER-4: SYSTEM PLANNING

4.1. Introduction

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

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

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 Intra State transmission system to satisfy requirement of future demand in accordance with the transmission system performance standards. The Planning Code:

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

(b) 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 intra State Transmission System;

(c) Details the information required by STU from Users to enable STU to plan the development of its intra State Transmission System to facilitate proposed User developments;

(d) Specifies planning and design standards, which will be applied by STU in planning and development of the power system.

4.3. Scope

The Planning Code applies to STU, other State Transmission Licensees, Intra-State Generating Station (IaSGS), connected to and/or using and involved in developing the IaSTS. This Planning Code also applies to Generating Companies, IPPs, Open Access Users and other licensees, regarding generation and/or transmission of energy to/from the IaSTS.

4.4. Planning Policy

4.4.1. STU would develop a perspective transmission plan for next 5 years for Intra State transmission system. These perspective transmission plans would be updated every year to take care of the revisions in load projections and generation capacity additions.

4.4.2. STU shall carry out annual planning process corresponding to a 5 year forward term for identification of major Intra State transmission system which shall fit into national power plan formulated by Central Government long term plan developed by CEA and the 5 year plan prepared by Central Transmission Utility.

4.4.3. 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 Distribution Licensees, 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.

Provided, area wise peak load hours forecasting shall be provided by the Distribution Licensee(s) to the STU.

II. Forecast the future generation capacity within the Area of Supply, based on the forecasts provided by generators in the State of Assam of any planned capacity additions, major planned outages or plant retirements.

III. Gather information on the future generation capacity available to the Area of Supply from generating stations outside of the state taking into account future inter-state transmission capacity.

IV. Prepare a forecast of the future generation surplus or deficiency taking into account future demand and generation capacity available from within and outside the state.

V. Prepare a transmission plan for the Intra State transmission system compatible with the above load forecast and generation forecast. This will include provision for VAR compensation needed in the Intra State transmission system.

VI. The reactive power planning exercise to be carried out by STU in consultation with NERLDC/NERPC, Distribution Licensees, as per AERC's directives and Programme for installation of reactive compensation equipment by STU & Distribution Licensees.

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

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

IX. 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.

X. STU shall be responsible to prepare and submit a long-term (5 years) plan to the Commission for transmission system expansion to meet the future demand growth and increases in generation capacity.

XI. **Transmission planning for Renewable energy**:

a. Wind and Solar generators shall mandatorily provide to the concerned SLDC, in a format prescribed by SLDC, the technical specifications at the beginning and whenever there is any change. The data relating to power system parameters and weather related data as applicable shall be mandatorily provided by such generators to concerned SLDC in real time. The frequency and other details in this regard shall be provided in the detailed procedure to be prepared by NLDC and approved by the Central Commission.

b. Forecasting shall be done by wind and solar generators which are state entities as well as the SLDC. The SLDC may engage forecasting agencies and prepare a schedule for such generating stations. The forecast by the SLDC shall be with the objective of ensuring secure grid operation. The forecast by the wind and solar generator shall be generator centric. The wind and solar generators which are state entities will have the option of accepting the SLDC's forecast for preparing its schedule or provide the SLDC with a schedule based on its own forecast. Any commercial impact on account of deviation from schedule based on the forecast chosen by the wind and solar generator shall be borne by it.

c. The schedule by wind and solar generators which are regional entities(excluding collective transactions) may be revised by giving advance notice to the SLDC, as the case may be. Such revisions shall be effective from 4^{th} time block, the first being the time-block in which notice was given. There may be one revision for each time slot of one and half hours starting from 00.00 hours of a particular day subject to maximum of 16 revisions during the day.

d. The schedule of solar generators which are state entities shall be given by the generator based on availability of the generator, whether forecasting, solar insolation/irradiance, season and normal solar generation curve.

XII. All the Users shall supply to STU, the desired planning data by 31st March every year to enable STU to formulate and finalize the plan by 30th September each year for the next 5 years on revolving basis.

4.5. Planning Philosophy

4.5.1. The STU shall carry out planning process from time to time as per the requirement for identification of intra-State transmission system including transmission system associated with Generation Projects and inter-state transmission system strengthening schemes which shall fit in with the perspective plan developed by CEA. While planning schemes, the following shall be considered in addition to the data of authenticated nature collected from and in consultation with Users by STU:

I. Perspective plan formulated by CEA.
II. Electric Power Survey of India published by the CEA.
III. Transmission Planning Criteria and guidelines issued by the CEA
IV. Grid Standards specified by the CEA under clause (d) of Section 73 of the Act
V. Operational feedback from RPC/RLDC/SLDC
VI. Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-state Transmission and related matters) Regulations, 2009 and AERC (Terms & Conditions of Intra-State Open Access) Regulations, 2018 amended from time to time.
VII. Renewable capacity addition plan issued by Ministry of New and Renewable Energy Sources & Assam Energy Development Agency (AEDA).
VIII. Reports on National Electricity Policy which are relevant for development of IaSTS;
IX. Any other information/data source suggested by the Commission.

4.5.2. In addition to the intra-state transmission system, the STU shall plan, from time to time, system strengthening schemes, need of which may arise to overcome the constraints in power transfer and to improve the overall performance of the grid. The intra-State transmission proposals including system strengthening scheme identified on the basis of the planning studies would be discussed, reviewed and finalized in the meetings of Grid Code Management Committee.

4.5.3. Based on above, the STU shall come out with a Transmission System Plan, the format of which can be decided by the State Transmission Utility.

4.5.4. The transmission system plan shall describe the plan for the IaSTS and shall include the proposed intra-State transmission schemes and system strengthening schemes

for the benefit of all Users. The transmission system plan shall include information related intra-State transmission lines, additional equipment including transformers, capacitors, reactors, Static VAR Compensators and Flexible Alternating Current Transmission Systems. Further, the transmission system plan shall also include information on targets set in the preceding plans and progress achieved on the identified intra-State/inter-State transmission schemes and system strengthening schemes.

4.5.5. As voltage management plays an important role in transmission of energy, special attention shall be given by STU for planning of capacitors, reactors, Static VAR Compensator (SVC) and FACTs etc. to optimize the use of the integrated transmission network.

4.5.6. The State Transmission Utility may, for the purpose of preparing the transmission system plan under these Regulations, seek such information as may be required by it from State Constituents, including generation capacity addition, system augmentation and long-term load forecast and all (approved/pending) applications for open access.

4.5.7. Provided that the Distribution Licensees shall have the primary responsibility for developing long term load forecasts for their respective license areas. The provisions related to load forecasting as provided in the Distribution Code shall be applicable. Provided also that the State Transmission Utility shall consider, but not be bound by, the information provided under this Regulation in preparing the transmission system plan.

4.5.8. All State Constituents and agencies will supply to the STU, the desired planning data from time to time to enable it to formulate and finalize its plan.

4.5.9. The plan reports shall contain a chapter on additional transmission requirement which may include not only intra-State transmission lines but also additional equipment such as transformer, capacitors, reactors etc.

4.5.10. Based on plans prepared by CTU, STU shall have to plan their systems to further evacuate power from ISTS and to optimize the use of integrated transmission network.

4.5.11. The plan report shall also indicate the action taken to fulfill the additional requirement and actual progress made on new schemes. These reports will be available to any interested party for making investment decision/connection decisions to the IaSTS.

4.5.12. The State Transmission Utility shall send a copy of transmission system plan for the IaSTS to the Commission by 31st December each year and also publish it on its website. The STU shall also make the same available to any person upon request

4.6. Planning Criterion

General Philosophy

4.6.1. The planning criterion are based on the security philosophy on which the IaSTS has been planned. The security philosophy may be as per the Transmission Planning Criteria and other guidelines as given by CEA. The general policy shall be as detailed below:

I. As a general rule, the IaSTS shall be capable of withstanding and be secured against the following contingency outages

a. without necessitating load shedding or rescheduling of generation during Steady State Operation:

i. Outage of a 132 kV Double Cicuit (D/C) line or,

ii. Outage of a 220 kV Double Cicuit (D/C) line or,

iii. Outage of a 400 kV Single Cicuit (S/C) line or,

iv. Outage of single Interconnecting Transformer, or

v. Outage of one pole of HVDC Bipole line, or one pole of HVDC back to back Station or

vi. Outage of 765 kV S/C line

b. without necessitating load shedding but could be with rescheduling of generation during steady state operation-

i. Outage of a 400 kV S/C line with Thyristor Controlled Series Compensation (TCSC), or

ii. Outage of a 400kV D/C line, or

iii. Outage of both pole of HVDC Bipole line or both poles of HVDC back to back Station or

iv. Outage of a 765kV S/C line with series compensation.

II. The above contingencies shall be considered assuming a pre- contingency system depletion (Planned outage) of another 220 kV D/C line or 400 kV S/C line in another corridor and not emanating from the same substation. The planning study would assume that all the Generating Units operate within their reactive capability curves and the network voltage profile are also maintained within voltage limits specified.

III. The IaSTS shall be capable of withstanding the loss of most severe single system infeed without loss of stability.

IV. Any one of these events defined above shall not cause:

a. Loss of supply

b. Prolonged operation of the system frequency below and above specified

limits.

c. Unacceptable high or low voltage

d. System instability

e. Unacceptable overloading of IaSTS elements.

V. In all substations (132 kV and above), at least two transformers shall be provided

a. STU shall carry out planning studies for Reactive Power compensation of IaSTS including reactive power compensation requirement at the generator's /bulk consumer's switchyard and for connectivity of new generator/ bulk consumer to the ISTS in accordance with Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-state Transmission and related matters) Regulations ,2009.

b. Suitable System Protection Schemes may be planned by NLDC/RLDC in consultation with CEA, CTU, RPC and the Regional Entities, either for enhancing transfer capability or to take care of contingencies beyond that indicated in (a) above

VI. However, some planning parameters of the Intra State transmission system may vary according to directives of AERC.

Planning Responsibility

4.6.2. The primary responsibility of load forecasting within Distribution Licensees' Area of Supply rests with respective Distribution Licensee. The Distribution Licensees 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 Distribution Licensees 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 Licensee shall satisfy itself as to the degree of certainty of the demand materializing .

4.6.3. The Generating Company (APGCL presently) 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.

4.6.4. STU shall initiate the planning for strengthening the Intra State transmission system for

evacuation of power from outside state stations.

4.6.5. Operation and Co-ordination Committee shall review and approve the load forecasts and the methodology followed by each of the Distribution Licensees.

4.6.6. The Intra State transmission system proposals identified on the basis of planning studies would be discussed, reviewed and finalised by the OCC.

4.7. Planning Data

4.7.1. 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:

I. Standard Planning Data (Generation)/ Standard Planning Data (Distribution)

II. Detailed Planning Data (Generation)/ Detailed Planning Data (Distribution)

4.7.2. To enable Users to co-ordinate planning design and operation of their plants and systems with the Intra 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:

I. Standard System Data (Transmission).

II. Detailed System Data (Transmission).

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

CHAPTER 5: CONNECTION CONDITIONS

5.1. Introduction

Connection Conditions specify the minimum technical, design and operational criteria, which must be complied with by STU and any person connected to, or seeking connection to Intra State transmission system. This section also set out procedures by which STU shall ensure compliance by any person with above criteria as pre-requisite for establishment of an agreed connection.

5.2. Objective

The objective of this section is to ensure the following:

a. All Users or prospective Users are treated equitably.

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

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

d. 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. Connection Standard

The applicable technical standards for construction of electrical plants, electric lines and connectivity to the IaSTS shall be as per CEA (Technical Standards for Construction of Electrical Plants & Electric Lines) Regulations, 2010, CEA (Technical standards for Connectivity to the Grid) Regulations, 2010 and CEA (Grid Standards) Regulations, 2010 amended from time to time.

5.4. Safety Standard

The applicable safety requirements for construction, operation and maintenance of electric plants and electric lines shall be as per CEA (Safety Requirements for construction, operation and maintenance of electrical plants and electric lines) Regulations 2011 and CEA (Measures Relating to Safety and Electric supply) Regulations, 2010 and amendments from time to time shall also be applicable

5.5. Procedure for Application

a. The User shall submit the application containing all the information as may be reasonable required to STU.

b. STU shall make a formal offer within 90 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 Intra State transmission system necessitated by the applicant's proposal and for obtaining any consent necessary for the purpose.

c. If the prescribed time limit for making the offer against any application is not

adequate, STU shall make a preliminary offer within the prescribed time indicating the extent of further timerequired for detailed analysis.

d. Any offer made by STU shall remain valid for a period of 60 days and unless accepted before the expiry of such period shall lapsethereafter.

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

f. The applicant shall furnish the detailed planning data as per AppendixB

g. STU shall be entitled to reject any application for connection to/or use of Intra State transmission system on the following conditions apart from others as considered reasonable.

h. If such proposed connection is likely to cause breach of any provision of its license or any provision of the Grid Code or any provision of IEGC or any provision criteria or any covenants, deeds or regulations by which STU is bound.

i. If the applicant does not undertake to be bound, in so far as applicable, by the terms of GridCode.

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

5.6. Connection Agreement

All Users connected to or seeking connection to the InSTS shall enter into a connection agreement with the STU/Transmission Licensee. However, in respect of existing connections a relaxation of one year is allowed so that present arrangement may continue in the interim. The process of renegotiation of the connection conditions shall be completed within this period of one year. In case it is determined that the compliance of connection conditions would be delayed further, the Commission may consider further relaxation for which a petition will have to be filed by the concerned User along with STU's recommendation/comments. The cost ofmodification, if any, shall be borne by the concerned user.

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

a. A condition requiring both parties to comply with the Grid Code.
b. Details of connection and/or use of system charges.
c. Details of any capital related payments arising from necessary reinforcement or extension of the system.
d. Diagram of electrical system to be connected.
e. General philosophy, guidelines etc on protection.
f. A Site Responsibility Schedule (Appendix-G)

5.7. Connection Point

5.7.1. State Sector Generating Station (SSGS)

Voltage at point of connection may be 400/220/132 kV or as agreed with STU. Unless specifically agreed with STU the Connection point shall be the outgoing feeder gantry of Power Station Switchyard.

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

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

5.7.2. Distribution Licensee

Voltage at point of connection for Distribution Licensee may be 33/11 kV or as agreed with STU.

The Connection point shall be the outgoing feeder gantry/cable termination on transmission tower/pole at STU's substation. STU shall maintain all the terminals; communication and protection for the metering system shall be as per the Metering Code. From the outgoing feeder gantry / transmission line cable terminal structure onwards, all electrical equipment shall be maintained by the respective Distribution Licensee.

5.7.3. North-Eastern Regional Transmission System

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

5.7.4. IPPs, CPPs, EHV Consumers and Open access customers

Voltage at point of connection may be 220/132 kV or as agreed with STU.
When sub-stations are owned by IPPs, CPPs, EHV Consumers or the Open access customers, the Connection point shall be the outgoing feeder gantry on their premises.

5.8. Site Responsibility Schedule

For every Connection to the Intra 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.

a. The ownership of equipment.

b. The responsibility for control of equipment.

c. The responsibility for maintenance of equipment.

d. The responsibility for operation of equipment.

e. The manager of the site.

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

5.9. System Performance

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

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

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

d. SSGS (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 Intra State transmission system. CPPs shall similarly furnish the net reactive capability that will be available for Export to / Import from State Grid

e. The User shall however be subject to the Grid discipline prescribed by SLDC/ NERLDC as per guidelines mutually agreed with NERPC / NERLDC.

f. Distribution Licensees and Open access users shall ensure that their loads do not affect STU system in terms of causing any:

g. Unbalance in the phase angle and magnitude of voltage at the interconnection point beyond the limits prescribed by Transmission Performance Standards.

h. Harmonics in the system voltage at the interconnection point beyond the limits prescribed by Transmission Performance Standards.

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

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

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

l. Protection schemes and metering schemes shall be as detailed in the Protection and Metering sections of the Code.

Detailed Performance Standards and its compliance requirements have been stated separately in the document namely "Assam Electricity Regulatory Commission (Transmission Licensee Performance Standards) Regulations, 2004" drafted under the

provisions of section 57 (1) read with section 86 (1) (i) of the Act.

5.10. Data Requirements:

5.10.1. Reliable and efficient speech and data communication systems shall be provided to facilitate necessary communication and data exchange must be incorporated.

5.10.2. Cyber security :

All utilities shall have in place a cyber security framework to identify the critical cyber assets and protect them so as to support reliable operation of the grid.

5.10.3. System recording instruments :

Recording instruments such as Data acquisition system/ Distribution recorder/ Event logging facilities/ Fault locator (including time synchronization equipment) shall be provided and always kept in working condition in the Assam grid for recording of dynamic performance of the system. All users and STUs shall provide all the requisite recording instruments and keep them in working condition.

5.10.4. Single line diagrams:

Single line diagram shall be furnished for each connection point by the connected users or Transmission licensee to the SLDC and /or the STU. These diagrams shall include all EHV/HV connected equipment and the connection to all external circuits and incorporate numbering, nomenclature and labeling etc. The diagram is intended to provide an accurate record of the layout and circuit connections, rating, numbering and nomenclature of EHV/HV apparatus and related plant.

Whenever any equipment is proposed to be changed, then concerned user shall intimate the necessary changes to STU and to SLDC. When the changes are implemented, revised single line diagram shall be circulated by the user to SLDC/STU.

5.11. Metering:

5.11.1. ABT metering :

All utilities shall have ABT meters in place for (1) inter-state interface (2) intra-state utility interface (3) open access consumers interface lines.

5.11.2. Insertion of new grid element :

Connection of a new grid element with the grid shall not be allowed unless and until all pre-conditions as stipulated in IEGC are complied with.

5.11.3. International connection to STS:

The procedure for international connection to state transmission system and the execution of agreement for the same shall be determined by STU in consultation with CEA, NERLDC and Ministry of power.

5.11.4. Generating Unit (equal or above 50MW) shall be capable of instantaneously increasing output by 5%, when the frequency falls subject to limit of 105% of maximum continuous rating. Ramping back to the previous generation level, in case

the increased output level cannot be sustained, shall not be faster than 1% per minute.

5.11.5. No LILO(loop in loop out) connection from STU shall be allowed to any agency other than transmission license.

5.11.6. All generating stations of the state shall participate in the restricted governor mode operation for operation of their units as illustrated in IEGC.

5.12. The permissible voltage domain :

The variation of voltage at the inter connection point may not be more than the voltage range specified below:

Limit of Voltage Variation - (kV rms*)

Nominal	Maximum	Minimum
765	800	728
400	420	380
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

 # Any amendment in permissible voltage domain by IEGC shall be a deemed amendment of State Grid Code

** Root Mean Square*

5.13. The permissible frequency domain :

The rated frequency of State Grid shall be 50.0 Hz and shall be regulated by the provisions of IEGC and any other Regulations as may be specified by the appropriate Commission.

PART III
LOAD DESPATCH & SYSTEM OPERATION CODE

CHAPTER 6: OPERATIONAL PLANNING

6.1. Operating Philosophy

The primary objective of integrated operation of the State Power Grid is to enhance the overall operational efficiency, reliability and economy of the entire electric power network spread over the geographical area of the State. Participant utilities shall therefore co-operate with each other and adopt Good Utility Practice at all times for satisfactory and beneficial operation of the State Power Grid.

a. Overall operation of the State Power Grid shall be supervised by the state load despatch centre (SLDC). All users and transmission licensees are accordingly required to comply with the directions given by the SLDC.

b. Distribution licensee shall establish DCC for smooth running and to monitor operation of its distribution system and to coordinate with the SLDC for better utilization of integrated grid.

c. SLDC shall prepare a draft operational manual as per the Grid Code for day to day operation and smooth handling of integrated grid. SLDC should also review the operational manual from time to time.

d. In order to facilitate estimation of total transfer capability (TTC)/ Available transfer capability(ATC) on three month ahead basis, the SLDC shall furnish estimated demand and availability data to RLDCs. SLDC also calculate the intra state TTC, ATC in consultation with RLDC and as per the guideline of AERC for better operation of Assam Grid.

e. URS (un-requisitioned surplus) and under-requisition should be placed before SLDC by the DCC as per the real time condition or at the advice of SLDC.

f. Line loading limits: The permissible line loading limits shall be as per CEA's manual on transmission planning criteria. The overloading and under loading of lines shall be decided accordingly.

g. Transformer loading limits: The permissible transformer loading limits shall be as per CEA safety standards or as specified by the competent authority from time to time.

6.2. System Security

6.2.1. The System Security relates to entire Inter-connected power system. The inter-connected power system consists of North-Eastern Regional System with New Grid. The system security aspect therefore affects all users of the national inter-connected power systems. However, the operation of the State Grid will be controlled and maintained by SLDC as per directions and instructions of NERLDC as per provisions of IEGC.

6.2.2. All switching operations, whether affected manually or automatic, will be based on policy guide lines of:

a. IEGC

b. NERLDC's instructions/guidelines

c. Grid Code

d. Grid Code Management Committee's decisions

e. State Government's directives

f. AERC's directives

6.2.3. No part of the Intra State transmission system shall be deliberately isolated from the integrated Grid, except.

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

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

c. When such isolation is specifically advised by SLDC and

d. On operation of under frequency/islanding scheme as approved by NERPC/AERC.

6.2.4. All such isolations shall be either as per standing guidelines approved by NERPC/AERC or shall be put up in the Grid Code Management 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 in accordance with NERLDC System Operating Procedure.

6.2.5. The 132 kV and above transmission lines and ICTs (except radial lines which do not affect the operation of the Grid) 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 Grid Code Management Committee for ratification in the next meeting.

6.2.6. 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 disturbance recorder, sequential event recorder outputs etc. containing the sequence of tripping and restoration shall be sent to SLDC for the purpose of analysis.

6.2.7. All generating units, which are synchronized with the state 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 NERLDC through SLDC shall be immediately advised about the reason and duration of such operation. All governors shall have a droop of between 3% and 6%. 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.

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

6.2.9. All Generating Units, operating at/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 state grid) only after obtaining the permission of NERLDC 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.

6.2.10. In case frequency falls below the limits as specified by IEGC from time to time, all partly loaded Generating Units shall pick up additional load at a faster rate, according to their capability curve. SLDC in consultation with NERPC/NERLDC and Distribution Licensee shall prepare a plan for automatic load relief during the low frequency conditions. In case frequency rises to above the limits as specified by IEGC from time to time, neither any generating unit shall be synchronized with the Grid nor shall generation at any generating station (irrespective of type of ownership) be increased without obtaining approval from SLDC.

6.2.11. 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 the SLDC, particularly when frequency is deteriorating.

6.2.12. 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 SLDC shall be immediately intimated about the reason and duration, and its concurrence

obtained.

6.2.13. 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.

6.2.14. Generating Stations shall follow the instructions of SLDC for backing down/ boxing up 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.

6.2.15. Provision of protections and relay settings shall be coordinated in the Intra State transmission system, as per a plan to be separately finalised by the Protection Co-ordination Committee.

6.2.16. Various steps shall be taken for frequency management and voltage management under Chapter 8 so as to ensure system security from these considerations.

6.2.17. All Generating Units with capacity of 50 MW and above, sub-stations with operating voltage of 400 kV & above and important 220 kV sub-stations with 220/132 kV transformation capacities above 50 MVA shall be provided with the facilities of Disturbance Recorders (DRs) and Event Loggers (ELs) as per IE Rules.

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

6.3. Safety Aspects

6.3.1. Electrical clearances:

The minimum safety working clearance shall be maintained for the bare conductor live parts of any apparatus in outdoor substation, excluding overhead lines of HV and EHV installation. (As per CEA latest notification).

6.3.2. Cross Boundary safety:

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

a. All users shall comply with the agreed safety rules drawn up in accordance with central electricity authority (measures relating to safety and electric supply) regulation, 2010 and amendments thereafter, if any.

b. All the equipment on cross boundary circuits, which may be used for the purpose of safety coordination and establishment of isolation and earthing, shall be permanently and clearly marked with an identification number or name being unique to the particular substation. The equipment shall be regularly inspected and maintained in accordance with the manufacturer's specification.

c. Each of the distribution licensees connected to the transmission system shall maintain an updated map of his system pertaining to the area fed by each substation, and exhibit the same in the concerned area offices of the distribution licensee.

6.3.2.2. Procedure for Cross Boundary Safety

a. STU/ Transmission Licensee shall issue a list of control persons with their names, designations, addresses and telephone numbers to all the users having direct control boundary with it. This list shall be updated promptly whenever there is any change of name, designation or telephone number of any control person named in the list.

b. Whenever any work across a cross boundary is to be carried out by the user or STU/Transmission Licensee as the case may be, who has to carry out the work, shall directly contact his counterpart. Code words shall be agreed to, at the time of work, to ensure correct identification of both the parties. Contact between control persons shall normally be made by direct telephone.

c. If the work extends beyond one shift, the control person shall hand over charge to the relief control person and fully brief him on the nature of work and the code words in the operation.

d. The control persons shall co-operate to establish and maintain the precautions necessary to be taken for carrying out the required work in a safe manner. Both the established isolation and the established earth shall be kept in the locked positions wherever such facilities exist, and these shall be clearly identified and entered into the log sheet.

e. The control person in charge of the work shall satisfy himself that all the safety precautions to be taken are established before commencing the work. He should issue the safety documentation to the working party to allow the work to commence.

f. After completion of the work, the control person in charge of the work being carried out, should satisfy himself that the safety precautions taken are no longer required, and shall make a direct contact with his counterpart control person and request removal of the safety precautions. The equipment shall be declared as suitable for return to service only after confirmation of removal of all the safety precautions by direct communication, using the code word contact between the two control persons, and the return of agreed safety documentation from the working party.

g. STU shall develop an agreed written procedure for cross boundary safety and continuously update the same.

h. Any dispute concerning cross boundary safety shall be resolved at the level of STU, if STU is not a party. In case where STU is a party, the dispute shall be

referred to the AERC for resolution.

6.4. Demand Estimation

6.4.1 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 System Planning Code. The SLDC shall be provided with a copy of the same as and when it is finalized. Demand estimation for period up to 1 year ahead shall be done by SLDC.

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

6.4.3 Distribution Licensees shall provide to SLDC estimates of load that may be shed when required, in discrete blocks with the details of arrangements of such load shedding.

6.4.4 Distribution Licensees shall also furnish realistic category-wise demand for their respective companies along with details of essential loads, supply hours to be maintained in rural areas, details of power cuts imposed or to be imposed and specific requirements, if any.

6.4.5 The demand estimation shall cover active power as well as reactive power requirements forecasted for each sub-station.

6.4.6 STU and 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 demand forecasting.

6.4.7 Distribution licensee shall carry out its own demand estimation from the historical data and weather forecast data from time to time.

6.4.8 The distribution licensee shall at regular interval review the status of loads materialized as per the previous load forecast. Distribution licensee shall further take the base data (i.e. actual energy and demand requirement of the previous financial year) and relate it to past trend.

6.4.9 SLDC based on the data received from distribution licensees and all other users carry out the state-wise demand estimation on daily/weekly/monthly/yearly basis for current year for load-generation balance planning and operational planning. Mechanism and facilities at SLDC shall be created at the earliest to facilitate on-line estimation of demand for daily operational use for each 15 minutes time block.

6.4.10 SLDC shall furnish data for and participate in deliberations for load generation balance or annual demand & availability and shunt capacitors requirement studies of NERPC. It shall take into consideration their reports for demand estimation for operational planning.

6.5. Demand Control

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

a. Variations in demand from the estimated or forecasted values, which cannot be absorbed by the grid

b. Unforeseen generation / transmission outages resulting in reduced power availability

c. Heavy reactive power demand causing low voltages

6.5.2. SLDC shall match the consolidated demands of the Distribution Licensees with consolidated generation availability from various sources and exercise the demand control to ensure that there is a balance between the energy availability and the Distribution Licensees demand plus losses and any requirement of generation reserve.

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

6.5.4. SLDC shall advice STU for planning of Automatic load shedding schemes and rotational load shedding through installation of Under Frequency Relays.

6.5.5. The guidelines for under frequency load shedding shall be prepared, in accordance with the instructions from NERLDC/NERPC, by the Operation and Co-ordination Committee and shall be approved by the Grid Code Management Committee.

6.5.6. 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 placed on Notice board and will also available at the sub-station for information of the consumer(s).

6.5.7. Demand control can also be exercised by the 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.

6.5.8. Rotational Load Shedding Schemes using Under Frequency Relay (UFR) shall be prepared time to time by the Utility in accordance with the guidelines/instructions issued by NERLDC/NERPC and these schemes shall be duly approved by AERC.

6.6. Load Crash

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

a. Backing down of hydel stations for short period immediately

b. Lifting of the load restrictions, if any

c. Exporting the power to neighbouring regions

d. Backing down of thermal stations with a time lag of 5-10 minutes for short period

e. Closing down of hydel units (subject to non spilling of water and effect on irrigation)

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

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

6.7. Demand Management:

6.7.1. ADMS (Automatic Demand Management Scheme) as per the guide lines of latest Regulations by CERC may be introduced. Within a time frame as desired by AERC, SLDC through the Distribution Licensee shall formulate and implement state-of-art demand management schemes for automatic demand management like rotational load shedding, demand response (which may include lower tariff for interruptible load) etc in addition to under frequency relays to reduce over drawal in order to comply with clause of regulation of IEGC 5.4.2.

6.7.2. All users shall make such arrangements that enable manual demand disconnection to take place, as instructed by the SLDC, under normal and/or contingent conditions. SLDC shall devise standard instantaneous message format in order to give directions in case of contingencies and /or or threat to the system security to reduce deviation from schedule by the Users or demand disconnections, as the case may be.

6.7.3. Planned manual Disconnection shall be implemented by the SLDC whenever there is a shortfall in generation, or constraints in Transmission System, or reduction of imports through external connection or any other reason, requiring demand control over prolonged period. However, in such cases SLDC shall adopt a rotational load-shedding scheme to ensure equitable treatment to all consumers as far as practicable. (In the case of shortage of power availability with respect to demand, the DCC shall resort to shedding the load of different feeders on economic principle.)

6.7.4. Emergency Manual Disconnection to deal with unacceptable voltage and frequency levels etc may be implemented by the SLDC only when there is major loss of generation resulting into mismatch of generation and drawal or there are constraints in the Transmission System. SLDC may also direct manual disconnection in cases of persistent over-drawal from the grid in excess of respective drawal schedule.

CHAPTER-7: SCHEDULE AND DESPATCH CODE

7.1. Introduction

This section specifies the procedure to be adopted for the scheduling and despatch of generating units to meet demand and drawal requirements of Distribution Licensees.

7.2. 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 specify the responsibilities of Users to furnish the necessary data for scheduling and to comply with that schedule.

7.3. General

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

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

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

c. Network constraints, if any such as expected duration of planned shutdowns and already existing forced outage of vital transmission elements during ensuingday

d. Overall economy to Distribution Licensees

e. 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 as a waste shall not be curtailed:

   i. Run of river or canal based hydro stations.

   ii. Hydro-station where water level is at peak reservoir level or expected to touch peak reservoir level (as per inflows).

   iii. Wind power stations.

   iv. Solar power stations (Other than hybrid).

f. Despatch instructions shall be in standard format. These instructions will recognize declared availability and other parameters that have been made available by the generating stations to SLDC. These instructions shall include time, Power Station, Generating Units, (Total export in case of CPP) and names of operators sending and receiving the despatch instructions.

g. Standard despatch instructions may include:

   i. To switch a SSGS into or out ofService.

ii. Details of reserve to be carried on a unit.
iii. To increase or decrease MVAr generation to assist with voltage profile as per unit capability at that time .
iv. To begin pre-planned Black Start procedures.
v. To hold spinning reserve.
vi. To hold Generating Units of SSGS on standby.
vii. To control MW/MVAr Drawl by Distribution Licensees.

7.4. Scheduling and Despatch Procedure

7.4.1. Each day, starting from 00.00 hours to 24.00 hours, shall be divided into 96 time blocks of 15 minutes intervals for the purposes of scheduling and despatch and energy accounting.

7.4.2. For all SSGS the station capacities and allocated / contracted shares of different beneficiaries shall be duly listed with SLDC and any changes in this regard shall be immediately informed to SLDC. Each beneficiary shall be entitled to a MW dispatch upto (foreseen ex-power plant MW capability of the block) x (beneficiary's share in the station capacity).

7.4.3. By **08.00 AM** every day all SSGS shall advise the SLDC, the station wise ex-power plant MW capacity as foreseen for each time block of the next day i.e. from 00.00 hours to 24.00 hours of the following day. For Hydro generating station, the declaration shall be made for a period of time not less than 3 hours within a 24 hours period for pondage and storage type of stations and for the entire day for purely run-of-river type stations. For hydro-generating stations, the declaration should also include limitation on generation during specific time periods, if any, on account of restriction on water use due to irrigation, drinking water, industrial, environmental considerations, etc.

7.4.4. The SLDC shall also receive information from RLDC regarding the MW and MWh entitlements for the State beneficiaries from ISGSs for each 15 minute time blocks for the next day by **08.00 AM**.

7.4.5. SLDC shall compile the above information, taking into account bilateral transactions, if any, and apportion it for the next day based on the entitlements of the beneficiaries in the State Sector Generating Stations, Inter-State Generating Stations and bilateral transactions and communicate the same to all the beneficiaries / DCCs by **10.00 AM.**

7.4.6. The beneficiaries/ DCCs shall prepare the drawal schedule according to their foreseen load pattern and their own generating capacity for the next day (if any, from generating plants such as that owned by the beneficiary itself, Captive Plants and NCES based plants connected to their distribution system), and advise the SLDC by **01:00 PM** their drawal schedule from SSGS and ISGS and long term, short term bilateral trades in which they have shares.

Provided that where distribution licensee has its own generating stations DCC shall follow the principles laid down above while preparing the dispatch schedule for own generating stations and submit the same to SLDC along with its drawal schedule.

Provided further that the beneficiary / DCC shall also show block wise projected demand under normal conditions along with reasons of restriction in drawal, if any, and its quantum.

7.4.7. SLDC shall compile the drawal schedules received from beneficiaries and determine the requirement from ISGS and injection schedule for SSGS considering the merit order despatch, ramp-up & ramp-down rate of generating stations and network conditions. SLDC shall convey by **03:00 PM** the requirement from each of ISGS to RLDC.

7.4.8. After considering the net drawal/injection schedule for the State for each 15 minute time block along with the entitlements from ISGS and all inter-state transactions, as intimated by RLDC by **06:00 PM** each day, the SLDC shall convey by **07:00 PM**

a. the ex-power plant "injection schedule" to each of the SSGS in MW for each 15 minutes time block for the next day. The summation of the ex-power plant drawal schedules advised by all beneficiaries shall constitute the ex-power plant station-wise / stage-wise injection schedule for SSGS.

b. the "net drawal schedule" to each beneficiary, in MW for each 15 minutes time block, for the next day. The summation of the station-wise ex-power plant drawal schedules from all the SSGS/ ISGS along with any drawal from / injection to State Grid corresponding to bilateral transactions and after deducting the transmission losses (estimated), shall constitute the beneficiary-wise net drawal schedule. The 15 minute time-block wise injection schedule for the generating stations of the licensee shall be mentioned separately.

7.4.9. While finalizing the drawal and despatch schedules as above, the SLDC shall ensure that the same are operationally reasonable, particularly in terms of ramping up and ramping down rates and ratio between minimum and maximum generation. SLDC shall also check that the resulting power flows do not give rise to any transmission constraints. In case of any foreseen generation/transmission constraints, the SLDC shall moderate the schedules to the required extent, under intimation to the concerned beneficiaries/SSGS.

7.4.10. The Beneficiaries, shall inform SLDC about any modification / changes to be made in the drawal schedule or bilateral transactions or injection schedule of its own generating station, if any, to SLDC by **09:00 PM**. Similarly, State Sector Generating Companies shall inform SLDC about any modification / changes in the foreseen despatch capabilities, to SLDC by **09:00 PM**.

7.4.11. The SLDC, accordingly, shall inform any modification / changes to be made in the station wise drawal schedule of ISGS and bilateral transactions, if any, to RLDC by **10:00 PM**.

7.4.12. The SLDC shall finally receive from RLDC the modified 'drawal schedule' against Central allocation along with bilateral transactions, if any, by **11:00PM.**

7.4.13. The SLDC shall review and revise the despatch schedules of the SSGS and drawal schedules of the beneficiaries in the light of the modified drawal schedule received from RLDC and convey by **11:30 PM:**

a. The updated ex-power plant "injection schedule" to each SSGS in MW for each 15-minute time block, for the next day.

b. The updated "net drawal schedule" to each of the beneficiary in MW for each 15-minute time block, for the next day along with the injection schedule of its embedded generating stations, if any.

7.4.14. In case of forced outage of a SSGS unit, SLDC shall revise the schedules on the basis of revised declared capacity by the SSGS. The revised declared capacity and revised schedules shall become effective from the 4^{th} time block, counting the time block in which the revision is advised by the SSGS to be the first one.

7.4.15. In case of forced outage of an ISGS unit, SLDC shall receive revised schedule from RLDC drawn on the basis of revised declared capacity by the ISGS. The revised declared capacity and revised schedules shall become effective from the 4^{th} time block, counting the time block in which the revision is advised by the ISGS to be the first one.

7.4.16. In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the intra- State Transmission System, associated switchyard and sub- stations owned by the State Transmission Utility or any other transmission licensee involved in intrastate transmission (as certified by the SLDC) necessitating reduction in generation, the SLDC shall revise the schedules which shall become effective from the 4^{th} time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. During the first, second and third time blocks of such an event, the scheduled generation of the SSGS shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised to be equal to their actual drawals.

7.4.17. In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the Inter- State Transmission System, necessitating reduction in generation of ISGS, the SLDC shall receive revised schedules from RLDC which shall become effective from the 4^{th} time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one.

7.4.18. In case of any grid disturbance, scheduled generation of all the SSGS and scheduled drawal of all the beneficiaries shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the RLDC/SLDC.

7.4.19. Revision of declared capacity by the SSGS and drawal requisition by beneficiary (ies) during any time block shall also be permitted based on advance notice. Revised schedules/declared capacity in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the SLDC to be the first one. The generating stations and the beneficiaries have to provide the reasons for revision request.

Provided that if there is load-shedding in the area of the distribution licensee, then SLDC may revise the schedule from 4th time block counting the time block in which the request for revision has been received in the SLDC to be the first one with the consent of generator.

7.4.20. In case of revision of declared capacity by the ISGS and requisition by beneficiary (ies) during any time block shall also be permitted on intimation from RLDC. Revised schedules/declared capacity in such cases shall become effective from the 6th time block, counting the time block in which the request for revision has been received in the RLDC to be the first one. SLDC shall intimate all the State beneficiaries about such modifications in the drawal/despatch schedules and advise them to effect corresponding change in their drawal schedules.

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

7.4.22. If, at any point of time, the RLDC observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own. On intimation of such revision by RLDC, SLDC shall intimate all the State beneficiaries about such modifications in the drawal/dispatch schedules and advise them to effect corresponding change in their drawal schedules.

7.4.23. To discourage frivolous revisions, the SLDC may, at its sole discretion, refuse to accept schedule/capacity changes of less than two (2) percent of the previous schedule/capacity.

7.4.24. Since variation of generation in purely run-of-river hydro generating stations may lead to spillage, these shall be treated as must run stations. The maximum available capacity in each time block, duly taking into account the over load capability, shall be equal to or greater than that required to make full use of the available water of

that time block. The run-of-river hydro-generating station with pondage, storage type hydro generating stations and pumped storage hydro-generating stations are designed to operate during peak hours to meet system peak demand. The maximum available capacity of a station declared for the day shall be equal to the installed capacity including overload capability, minus auxiliary consumption and transformation losses, corrected for the reservoir level. The DCC/ SLDC shall ensure that generation schedules of such type of stations are prepared and the stations dispatched for optimum utilization of available hydro energy except in the event of specific system requirements/constraints.

7.4.25. Wind and Solar generators

a. Wind and solar generators connected to STS shall mandatorily provide to the SLDC, in a format as prescribed by SLDC, the technical specifications at the beginning and wherever there is any change, the data relating to power system parameters and whether related data as applicable shall also be mandatorily provided by such generators to SLDC in real time. In case of wind and solar generators (including rooftop PV solar plants) connected to distribution licensee and sales its power to the distribution licensee they shall submit their above mentioned information to respective DCC.

b. Forecasting shall be done by wind and solar generator as well as the SLDC/DCC as the case may be. The SLDC / DCC may engage forecasting agency (ies) and prepare a schedule for such generating stations. The forecast by the SLDC / DCC shall be with the objective of ensuring secure grid operation. The forecast by the wind and solar generator shall be generator centric. The wind and solar generation which are connected with STS will have the option of accepting SLDC's forecast for preparing its schedule or provide the SLDC with a schedule based on its own forecast.

   Any commercial impact on account of deviation from schedule based on the forecast chosen by the wind and solar generator shall be borne by it.

c. The schedule by wind and solar generators who are connected with STS (excluding collective transactions) may be revised by giving advance notice to the SLDC, as the case may be. Such revisions shall be effective from 4th time block, the first being the time-block in which the notice was given. There may be one revision for each time slot of one and half hours starting from **00:00 hours** of a particular day subject to maximum of 16 revisions during the day.

d. The schedule of wind and solar generators who are connected to any distribution licensee network and whose power is purchased by the same distribution licensee shall be prepared by the DCC based on availability forecasted by the generators or DCC as per the PPA entered between them. DCC shall revise the schedule suo-motu or on advance notice from the generators based on revised

availability, if any. DCC may, if required, ask SLDC to revise its net drawal schedule from the Grid. However, in all cases DCC shall restrict its net drawal / injection from the State Grid within its net drawal schedule. Commercial settlement between distribution Licensee and wind and solar generation in case of any mismatch will be dealt as per PPA entered between them.

e. The schedule of solar generators shall be based on availability of the generator, weather forecasting, solar insolation/ irradiance, season and normal solar generation curve, etc.

7.4.26. For infirm power the generating stations shall give a 15 minute time-block wise tentative schedule of injection to beneficiary which shall be adjusted to its actual injection during the day while preparing the final net drawal schedule of the beneficiary.

7.4.27. Generation schedules and drawal schedules issued / revised by the SLDC shall become effective from designated time block irrespective of communication success.

7.4.28. For any revision of scheduled generation, including post facto deemed revision; there shall be a corresponding revision of scheduled drawals of the beneficiaries.

7.4.29. A procedure for recording the communication regarding changes to schedules duly taking into account the time factor shall be evolved by SLDC in consultation with STU and Users.

7.4.30. When for reason of transmission constraints e.g. congestion or in the interest of grid security, it become necessary to curtail power flow on a transmission corridor, the exchanges already scheduled may be curtailed by the SLDC. In the process the Short-term customers shall be curtailed first followed by the medium term customers, which shall be followed by the long-term customers and among the customers of a particular category, curtailment shall be carried out on prorate basis.

7.4.31. After the operating day is over at **24:00** hours, the provisional final schedule for the day (taking into account all before-the-fact changes in dispatch schedule of generating stations and drawal schedule of the Users/ beneficiaries) shall be issued by SLDC by 6:00 A.M. of the next day.

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

7.4.33. The provisional final schedules issued by SLDC, shall be open to all users for any checking/verification, for a period of 3 days. In case any mistake/omission is detected, SLDC shall forthwith make a complete check and rectify the same and issue the Final Schedule by the fifth day. These final schedules shall be the datum for commercial accounting.

7.4.34. SLDC shall assign suitable functions to the DCCs (established across the State) to help it in discharge of its different functions under section-32 of the Electricity Act 2003 including scheduling and despatch.

7.4.35. SLDC shall develop the formats for scheduling and modify the same as and when required in consultation with SGGC and put before the Commission for approval. Such approved forms will be used for all Scheduling and Despatching purpose.

7.4.36. While availability declaration by SSGS may have a resolution of one decimal (0.1) MW and one decimal (0.1) MWh, all entitlements, requisitions and schedules shall be rounded off to the nearest two decimals, to have a resolution of 0.01 MW.

Note: Any change in the schedule by SLDC shall be intimated to all the Beneficiaries, SSGS and RLDC as may be necessary.

CHAPTER 8: FREQUENCY AND VOLTAGE MANAGEMENT

8.1. Introduction

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

8.1.2. State Grid normally operates in synchronism with the National Grid and NERLDC has the overall responsibility of the integrated operation of the North-Eastern Regional Power System. The constituents of the Region are required to follow the instructions of NERLDC for the backing down generation, regulating loads, MVAR drawal etc. to maintain the system frequency and the grid voltage.

8.1.3. SLDC shall instruct SSGS 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.

8.1.4. System voltages levels can be affected by Regional operation. The SLDC shall optimise voltage management by adjusting transformer taps to the extent available and switching of circuits/ capacitors/ reactors and other operational steps. SLDC will instruct generating stations to regulate MVAr generation within their declared parameters. SLDC shall also instruct Distribution Licensees to regulate demand, if necessary.

8.2. Objective

8.2.1. The objectives of this section are as follows:

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

b. To define the actions required to enable SLDC to maintain System voltages and frequency within acceptable levels in accordance Planning and Security Standards of IEGC.

8.3. Frequency Management

The rated frequency of the system shall be 50 Hz and shall normally be regulated within the limits prescribed in Clause 5.13. As a constituent of North-Eastern Region, the SLDC shall make all possible efforts to ensure that grid frequency remain within normal band of 49.90 – 50.05 Hz.

8.4. Basic Philosophy of Control

Frequency being essentially the index of load-generation balance conditions of the system, matching of available generation with load, is the only option for maintaining frequency within the desired limits. Basically, two situations arise, viz., a surplus situation and a deficit situation. The automatic mechanisms available for adjustment of load/generation are (i) Free

governor action; (ii) Maintenance of spinning reserves and (iii) Under-frequency relay actuated shedding. These measures are essential elements of system security. SLDC shall ensure that Users of the State Grid comply with provisions of clause 6.2 of the IEGC so far as they apply to them. The SLDC in coordination with Users shall exercise the manual mechanism for frequency control under following situations:

8.4.1. Falling Frequency:

Under falling frequency conditions, SLDC shall take appropriate action to issue instructions, in co- ordination with NERLDC to arrest the falling frequency and restore it to be within permissible range. Such instructions may include dispatch instruction to SSGS and/or instruction to Distribution Licensees and Open access customers to reduce load demand by appropriate manual and/or automatic load shedding.

8.4.2. Rising Frequency

Under rising frequency conditions, SLDC shall take appropriate action to issue instructions to SSGS in co-ordination with NERLDC, to arrest the rising frequency and restore frequency within permissible range through backing down hydel generation and thermal generation to the level not requiring oil support.. SLDC shall also issue instructions to Distribution Licensees and Open access customers in coordination with NERLDC to lift Load shedding (if exists) in order to take additional load.

8.5. Responsibilities

SLDC shall monitor actual Drawal against scheduled Drawal and regulate internal generation/demand to maintain this schedule. SLDC shall also monitor reactive power drawal and availability of capacitor banks. Generating Stations within Assam shall follow the despatch instructions issued by SLDC. Distribution Licensees and Open access customers shall co-operate with SLDC in managing load & reactive power drawal on instruction from SLDC as required.

8.6. Voltage Management

The Following processes/apparatus shall be adopted for Voltage Management:

8.6.1. Users using the Intra State transmission system shall make all possible efforts to ensure that the grid voltage always remains within the limits specified at clause 5.12 of this Code.

8.6.2. 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 SSGS to maintain specified voltage level at interconnecting points. SLDC and STU shall co-ordinate with the Distribution Licensees to determine voltage level at the interconnection points. SLDC shall continuously monitor 400/220/132kV voltage levels at strategic sub-stations to control System

voltages.

8.6.3. SLDC in close coordination with NERLDC shall take appropriate measures to control System voltages which may include but not be limited to transformer tap changing, capacitor / reactor switching including capacitor switching by Distribution Licensees at 33 kV substations, operation of Hydro unit as synchronous condenser and use of MVAr reserves with SSGS within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

8.6.4. APGCL and IPPs shall make available to SLDC the up to date capability curves for all Generating Units, as detailed in Chapter 5.indicating any restrictions, to allow accurate system studies and effective operation of the Intra State transmission system. CPPs shall similarly furnish the net reactive capability that will be available for Export to / Import from Intra Statetransmission system.

8.6.5. Distribution Licensees 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.

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

8.7. Reactive Power Management:

The Following processes/apparatus shall be adopted for Reactive Power Management:

8.7.1. Reactive Power compensation and/or other facilities should be provided by Transmission Licensee/Distribution licensees as far as possible close to the load points thereby avoiding the need for exchange of Reactive Power to/from Intra STS and to maintain Intra STS voltage within the specified range.

8.7.2. Line Reactors may be provided to control temporary over voltage within the limits as set out in connection agreements.

8.7.3. The additional reactive compensation to be provided by a User, shall be indicated by STU in the Connection Agreement for implementation.

8.7.4. Use of Shunt Capacitor at 33 KV or lower voltage level.

8.7.5. Switchable shunt reactors shall be provided at 400/220 kV sub-stations for controlling voltages within the limits specified. The step changes shall not cause a voltage variation exceeding 5%. Suitable line reactors (switchable/fixed) shall be provided to enable charging of 400/220 kV lines without exceeding voltage limits specified. The line reactors shall be installed for long line at high voltage level for curtailing switching over voltage and limiting the fault currents.

CHAPTER 9: MONITORING OF GENERATION AND DRAWAL

9.1. Introduction

The monitoring of generation output and reserve capacity of SSGS by SLDC is important to evaluate the performance of generation plants.

The monitoring of scheduled drawal is important to ensure that STU, Distribution Licensees and Open Access customers observes Grid discipline and contributes towards improving system performance.

9.2. Objective

The objective of this section is to define the responsibilities of all SSGS in the maintaining Generating Unit's reliability and performance, and STU's, Distribution Licensees & Open Access Customers' compliance with the scheduled Drawal, to assist SLDC in maintaining Grid discipline.

9.3. Monitoring Procedure

9.3.1. For effective operation of the Intra State transmission system, it is important that a SSGS's declared availability is realistic.

9.3.2. 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 SSGS declared availability may not match the actual availability or declared output does not match the actual output.

9.3.3. 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.

9.3.4. SLDC shall inform a SSGS, 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 Grid Code Management Committee with a view to either improve performance in future, providing more realistic declarations or initiate appropriate actions for any breach of Connectivity Conditions.

9.3.5. SSGS (excluding CPPs) shall provide to SLDC hourly generation summation outputs where no automatically transmitted metering or SCADA/RTU equipment exists. CPPs shall provide to SLDC hourly export / import MW and MVAr.

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

9.4. Generating Unit Tripping

9.4.1. SSGS (excluding CPPs) shall promptly inform the tripping of a Generating Unit, with reasons, to SLDC in accordance with the operational Event/Accident Reporting section. SLDC shall keep a written log of all such tripping, including the reasons with a view to

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

9.4.2. SSGS (excluding CPPs) shall submit a more detailed report of Generating Unit tripping to SLDC monthly.

9.5. Monitoring of Drawal

9.5.1. SLDC shall continuously monitor actual MW Drawal by Distribution Licensees and open access customers against that scheduled by use of SCADA equipment where available, or otherwise using available metering. STU shall request NERLDC and adjacent States as appropriate to provide any additional data required to enable this monitoring to be carriedout.

9.5.2. SLDC shall continuously monitor the actual MVAr Drawal to the extent possible. This will be used to assist inIntra State transmission system voltage management.

9.6. Data Requirement:

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

CHAPTER-10: OUTAGE PLANNING

10.1. Introduction

10.1.1. This section sets out the procedure for preparation of outage schedules for the elements of the State Power Grid in a coordinated and optimal manner keeping in view the State power system operating conditions and the balance of generation and demand. (A List of elements of the state grid covered under these Regulations shall be prepared by SLDC in consultation with the STU and all other users).

10.1.2. The generation capacity and transmission system should be adequate after taking into account the outages to achieve the security standards.

10.1.3. The State's annual outage plan shall be prepared in advance for the financial year by the GCMC and reviewed during the year on quarterly and monthly basis.

10.2. Objective

10.2.1. To produce a coordinated generation outage programme for the State Power Grid, considering all the available resources and taking into account transmission constraints, as well as, irrigational requirements.

10.2.2. To minimize surplus or deficits, if any, in the system requirement of electricity demand (MW) & energy (kWh) and help operate system within Security Standards.

10.2.3. For optimum management of transmission outages without adversely affecting the grid operation but taking into account the generation outage schedules, planned outages of distribution system and transmission systems and maintaining system security standards.

10.3. Scope

This section is applicable to all users including SLDC, STU, GCMCGCMC and all other users connected to the state power grid.

10.4. Outage Planning Process

10.4.1. The SGGC shall be responsible for analyzing the outage schedule given by all the users, preparing a draft annual outage schedule and finalization of the annual outage plan, which shall be in line with the Regional annual outage plan finalized by RPC for the following financial year.

10.4.2. All Generating Companies and Licensees including STU shall furnish their proposed scheduled outage program indicating the Units/Lines/Sub-stations/ICTs etc, date of start of outage and duration of outage in writing to the GCMC Secretariat for the ensuing financial year by 15th of September each year. Distribution Licensees are however not required to intimate outages, which might induce load loss of less than 20 MW demand in their area of supply.

10.4.3. The GCMC shall prepare an optimum draft outage plan minimizing interruption to the consumers on the basis of data submitted by the Generating Companies and the Licensees. SGGC shall make available the draft Scheduled Outage Plan to RPC by 31st October each year.

10.4.4. Based on refinement by the RPC secretariat in the draft inter- State outage Plan, the GCMC shall also review and revise the State's Scheduled Outage Plan and intimate all Users and SLDC, the final Scheduled Outage Plan for implementation latest by 31st January each year.

10.4.5. The above annual outage plan shall be reviewed by SGGC on quarterly in coordination with all parties and considering updated Regional outage plan and adjustments made wherever found to be necessary.

10.4.6. In case of emergency in the system viz., loss of generation, break down of transmission line affecting the system, grid disturbance, system isolation, the SLDC, may conduct studies again before clearance of the planned outage.

10.4.7. The SLDC is authorized to defer the planned outage in case of any of the following, taking into account the statutory requirements:

a. Major grid disturbances (Total black out in the State/Region)

b. System isolation

c. Partial Black out in the State

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

e. Generating Companies and Licensees shall plan their activities as per the latest annual scheduled outage plan finalized by the SGGC (with all adjustments made to date).

f. All Users shall obtain the prior approval from SLDC for availing an outage

g. User's requests for additional outages will be considered by SLDC to accommodate to the extent possible

CHAPTER-11: CONTINGENCY PLANNING

11.1. Introduction

This section describes the procedure be followed/ implemented by SLDC and all the Users of State Grid under the following abnormal system conditions:

a. Total system black out (Black Start mandatory)

b. Partial system black out

c. System Split or Islanding

11.2. Objective

11.2.1. To achieve restoration of total regional grid/state grid in shortest possible time taking into account essential loads, the generator capabilities and operational constraints of regional and intra State transmission system.

11.2.2. To achieve resynchronisation of the part of the State Grid which have become out of synchronous with Regional System/State Grid.

11.2.3. To ensure that all Users of State Grid are aware of the steps to be taken during major grid disturbances.

11.3. Contingency Planning Procedure

11.3.1. SLDC in close coordination with NERLDC shall be prepared to face and efficiently handle the following two types of contingencies:

a. Partial system black out in the state due to multiple tripping of the transmission lines emanating from power stations/sub-station.

b. Total black out in the state/region

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

11.3.3. In case of total regional black out, SLDC In-charge shall co-ordinate and follow the instructions of NERLDC, for early restoration of the entire grid. After total collapse, for each power station, to avoid damage to the turbine, survival power is required. To meet the survival power, the diesel generating (DG) sets of sufficient capacity shall be available at each power station. The hydel stations and interstate supply, if available shall give start-up power to the thermal station. All possible efforts are 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 condition. For safe and fast restoration of supply, STU shall formulate the proper sequence of operation for major generating units, lines,

transformers and load within the state in consultations with NERPC. The sequence of operation shall include closing/tripping of circuit breakers, isolators, on-load tap-changers etc.

11.4. Restoration Procedure

The procedure for restoration of State Grid shall be prepared by the SLDC in close coordination with NERLDC and shall be in conformity to the System Restoration Procedure of the North-Eastern Region prescribed under IEGC.

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

11.5. Special Considerations

During restoration process following State Grid or Regional system blackout conditions, normal standards of voltage and frequency shall not apply.

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

All Users shall pay special attention in carrying 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.

11.6. Post Disturbance Analysis

11.6.1. SLDC as per guidelines and instructions from NERLDC shall carryout the post disturbance analysis of all major grid disturbances resulting into total or partial system blackout and system split and out- off synchronism 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 NERLDC.

11.6.2. Protection Coordination Committee shall also review the data collected and the 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 NER, to be carried out by the Grid Users.

11.6.3. In case of emergency in the system; viz. loss of generation, breakdown of transmission line affecting the system, grid disturbances or system isolation, SLDC may conduct studies again before clearance of the planned outage. Each

user and STU shall obtain the final approval from SLDC prior to availing an outage. These reports of shutdown and any deviation from the schedule shutdown and blackout(Full/Partial) shall be put up on the SLDC website.

11.6.4. The Transmission Licensees shall provide the SLDC their proposed outage programmes in writing for the succeeding month by 25th of every month. These shall contain- identification of each Generating Unit/Transmission Line/Interconnecting Transformer for which outage is being planned, reasons for outage, the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date.

11.6.5. SLDC shall devise standard, instantaneous, message formats in order to give directions in case of contingencies and /or threat to the system security to reduce over-drawal by the Distribution Licensees / Open Access Customers at different over-drawal conditions depending upon the severity of the over-drawal. The concerned utility shall ensure immediate compliance with these directions of SLDC and send a compliance report to SLDC.

11.6.6. SLDC shall prepare the Black Start procedure and the same shall be furnished to RLDC for their comment / modification.

CHAPTER 12: OPERATIONAL EVENT/ACCIDENT REPORTING

12.1. Introduction

This section describes the reporting procedure in writing of reportable events affecting the State Grid.

12.2. Objective

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

12.3. Reportable Incidents

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

a. Exceptionally high / low system voltage or frequency.

b. Serious equipment problem i.e. major circuit breaker, transformer or bus bar.

c. Loss of major Generating Unit.

d. System split, Intra State transmission system breakaway or Black Start.

e. Tripping of Transmission Line, ICT (Inter connecting transformer and capacitor banks)

f. Major fire incidents.

g. Major failure of protection.

h. Equipment and transmission line overload.

i. Accidents-Fatal and Non-Fatal.

j. Load Crash / Loss of Load

k. Excessive Drawal deviations.

l. Minor equipment alarms.

The last two reportable incidents are typical examples of those, which are of lesser consequence, but which still affect the State Grid 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.

12.4. Reporting Procedure

12.4.1. Reporting Time for events and accidents

a. All reportable incidents occurring in lines and equipment of 33 kV and above affecting the State Grid shall promptly be communicated by the User whose equipment has experienced the incident (The Reporting User) to any other significantly affected Users and to SLDC.

b. Within 1 (one) hour of being informed by the Reporting User, SLDC may ask for a

written report on any incident.

c. If the reporting incident cannot be classed as minor then the Reporting User shall submit an initial written report within two hours of asking for a written report by 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.

d. In other cases the Reporting User shall submit a report within 5 (five) working days to SLDC. SLDC may call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been source of the reportable incident.

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

   i. Location of incident.

   ii. Date and time of incident.

   iii. Plant or equipment involved.

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

   v. Supplies interrupted and duration if applicable.

   vi. Amount of generation lost if applicable.

   vii. Brief description of incident.

   viii. Estimate of time to return to service.

   ix. Name of originator.

   x. Possibility of alternate arrangement of supply

The above shall not relieve any User from the obligation to report events in accordance with section 161 of the Act.

12.4.2. Reporting Form

The standard reporting form other than for accidents shall be as agreed from time to time by the Grid Code Management Committee. A typical form is attached as an Appendix 6.

12.4.3. Major Failure

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

12.4.4. Accident Reporting

Reporting of accidents shall be in accordance with the Indian Electricity Rules, 1956, section 44-A. In both fatal and non-fatal accidents, the report shall be sent to the Electrical Inspector in the prescribed form.

PART-IV

PROTECTION CODE

CHAPTER-13: PROTECTION

13.1. Introduction

In order to safeguard intra-State transmission system and Users' system from faults it is essential that certain optimum standards for protection be adopted. This section describes these optimum standards.

13.2. Objective

The objective of this section is to define the optimum protection requirements for any equipment connected to the intra-State transmission system and thereby minimise disruption due to faults.

13.3. General Principles

13.3.1. 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. Optimum 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 in the systems of other entities.

13.3.2. No item of electrical equipment shall be allowed to remain connected to the intra-State transmission system unless it is covered by optimum specified protection aimed at reliability, selectivity, speed and sensitivity.

13.3.3. 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.

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

13.3.5. Special Protection Scheme (SPS): The STU shall commission the necessary SPS for prevention of transfer and spread of disturbance from one part of the grid to other parts of the grid. Necessary co-ordination, whenever necessary, with RLDC and the CTU shall be maintained by the SLDC and the STU.

13.3.6. SLDC shall advice STU regarding:

a. Planning for upgrading and strengthening protection system based on analysis of grid disturbance and partial/total blackout in State Grid.

b. The STU shall plan for installation of Islanding Scheme(s) through Under

frequency Relays and/or df/dt Relays at the designated locations.

c. Under-Frequency relay for load shedding, Relays provided for islanding scheme, disturbance recorder and fault locator installed at various sub-stations shall be tested and calibrated. The Protection Practices and Protocol Manual shall have provision for the same.

13.4. Protection Co-ordination

A Protection Coordination Committee (PCC) shall be constituted of the 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 malfunction of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection mal-function or issue as discussed and agreed to in these periodical meetings.

13.5. Fault Clearance Times & Short-time Ratings

From a 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 intra State transmission system, or any faults on the intra State transmission system itself, are as follows:

Nominal Voltage	Minimum Short Circuit current rating and duration of Switchgear		Target Fault clearance Time
kV	kA (rms)	Seconds	msec.
400 kV	40	1	100
220 kV	40	1	120
132 kV	31.5	3	120

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 Distribution Licensee/ Open access customers directly connected to intra State transmission system. At generating stations, line faults should be cleared at the generation station end, within the critical clearing time, for the generators to remain in synchronism.

13.6. Generator Requirements

13.6.1. All Generating Units and all associated electrical equipment of the Generating Units connected to the Intra-State transmission system shall be protected by adequate protection so that the Intra-State transmission system does not suffer due to any disturbances originating from the Generation units.

13.6.2. The generator protection schemes shall cover at least Differential protection, back up protection, Stator Earth fault protection, field ground/field failure protection (not applicable to brush-less excitation system), negative sequence protection, under frequency, over flux

protection, back-up impedance protection and pole slipping protection (applicable to units above 200MW), loss of field protection, reverse power protection etc.

13.7. Transmission Line Requirements

13.7.1. General

a. 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 from time totime.

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

c. Relay Panels for the protection of lines of STU taking off from a Power Station, shall be owned and maintained by 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 and with STU approval. All such issues shall be put up in the next 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.

13.7.2. 400 kV Transmission Lines:

a. Main-1 & Main-2 non-switched type Distance Protection Relay(DPR) with 4 Zone (minimum).

b. Additional zones can be added as per practical requirement

c. One zone should be set as reverse zone

d. Permissive Inter Trip Transfer may be incorporated as –

e. Zone-2 operation of relay at the first end with carrier being received from the far end relay.

f. Zone-1 operation of relay at the far end with carrier being received from the first end relay.

g. Direct Trip Transfer to the remote end can be planned as :

   i. Manual Trip of Circuit Breaker(CB).

   ii. Bus bar differential tripping with Local Breaker Backup (LBB).

   iii. Operation of three phase trip relay for any delayed tripping

   iv. Single pole auto-reclose with configurable dead time and reclaim Time.

h. Line differential Scheme shall be incorporated for short line as per CEA guideline.

i. Setting of DPRs may be calculated as per the recommendations of CEA Task Force headed by V. Ramakrishna

j. Configuration of Directional Earth Fault function as in inherent in Numerical DPR with a delay more than zone-3 time.

k. Bus-bar differential relay

l. LBB relay

13.7.3. 400 kV Bus-bars:

All 400kV sub-station shall have bus bus-bar differential protection scheme along with LBB and auto-reclosures for transmission lines.

13.7.4. 220kV Transmission Lines

Same as the provisions related to 400 kV line, except adoption of directional idmt Over-current Protection as illustrated in CEA protection guide line.

13.7.5. 220kV Bus Bars

Identified important 220kV sub-station shall have bus bus-bar differential protection scheme along with LBB and auto-reclosures for transmission lines.

13.7.6. 132 kV Lines

a. Main protection – 1 DPR NON-SWITCHED TYPE NUMERICAL RELAY (4 Zones)

b. Numerical Back-up protection (Over current & Earth fault)

c. LBB

d. Three pole auto reclose with synchro-check mode

e. Permissive Inter Trip (PUTT) or Permissive Overreach Trip Transfer (POTT) as per the length of the transmission line.

13.7.7. For short transmission line, appropriate alternative protection schemes may be adopted.

13.8. Transformer Requirements

13.8.1. The protection of Auto 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 protection function for transformers for all voltage levels should have _

a. % Numerical Differential protection with bias curve

b. Restricted E/F (REF) Protection (HV side/ LV side/ Overall), Single side or Both side can be used for Yn Yno and Overall for auto-transformers.

c. Over excitation

d. IDMTL over-current & Earth fault (numerical)

e. Instantaneous element for Back-up relays may be considered after accurate calculation of fault level.

f. REF can be chosen as (i) High Impedance type (ii) Low Impedance type

g. In addition to the above schemes the following electro-mechanical protection should

be in place :

i. Buchcholz Relay

ii. WTI / OTI

iii. Pressure Release Valve (PRV).

iv. OSR

h. If any Auto-Transformer is having a loaded tertiary delta connection, then neutral displacement relay should be in use for delta winding.

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

13.8.3. It is recommended that the following minimum protections should be provided for transformers:

a. All 400kV class power transformers shall be provided with 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 directional feature and inter-tripping of both HT and LT 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. It is recommended to have Double Buchhloz Protection Scheme for transformer tank.

b. All 220kV class power transformers shall have same protections as mentioned in section **a** above, except REF protection.

c. For 132kV and 33kV class transformers of capacity 5 MVA and above, the protections shall be same as mentioned in section **a** above, except over- fluxing relays, REF and PRV.

d. For 33kV 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.

13.8.4. Restricted Earth Fault (REF) requirements:

a. For all 220kv class and 132kv class transformers REF is a must along with over-fluxing and PRV (Pressure Release Valve) relays

b. For 33kv class 5 MVA & above the transformers must be equipped with Numerical Differential Protection with Back-up O/C (Over current) & E/F (Earth fault) schemes. REF and Over-fluxing relay may not be required in this category.

13.8.5. Distribution System

a. For 33kV 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.

b. For smaller transformers of HV class on the Distribution System, differential protection shall be provided for 7.5 MVA and above along with back up time lag over current and earth fault protection shall be installed for the windings.

c. Transformers of 1.0 MVA and above but less than 7.5 MVA shall be protected by non-directional IDMT over current relays (3 nos.) and earth fault relay (1 no.) on both HV and LV side.

d. In addition, all transformers of 1.0 MVA and above shall be provided with Buchholz relay, winding temperature and oil temperature protection in addition to the above mentioned relays wherever circuit breakers exist.

e. Provided that for existing transformers, where protection as above are not existing, above protection shall be deliberated in Protection Co-ordination Committee and provided in phased manner within 3 years.

13.9. 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 /or provisions in I.E. Rules.

13.10. Calibration & Testing:

The protection scheme shall be tested at each 400 kV, 220 kV, 132 kV & 66 kV sub-station by STU once in a year 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 APGCL. The overall co-ordination between APGCL and STU shall be decided in meeting of Protection Co-ordination Committee. The Protection Co-ordination Committee shall review the testing and calibration as and when needed.

13.11. Data Requirements

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

PART V
METERING CODE

CHAPTER-14: Metering

14.1 Special energy meters with remote terminal units (RTU) to facilitate SLDC in real time monitoring shall be installed at the interface locations.

14.2 Energy Accounting and Audit meters are to be installed at Power Stations and at Sub-Stations for accounting of the electricity to various segments of electrical system so as to carry out further analysis to determine the consumption and loss of energy over a specified time period. Records of calibration shall be maintained for reference and shall be made available to the STU/SLDC.

14.3 Installation and Operation of the meters shall be in accordance with the Central Electricity Authority (Installation and Operation of the meters) Regulations, 2006 and amendments thereof.

PART VI

DATA REGISTRATION CODE

CHAPTER 15: DATA REGISTRATION

15.1. 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 Grid Code. Other section of the Grid Code contains the obligation to submit the data and defines the times when data is to be supplied by Users.

15.2. Objective

The objective of the 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 Grid Code.

15.3. Responsibility

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

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

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

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

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

15.4. Data Categories and Stages in Registration

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

15.5. 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 to its own system.

15.6. Methods of Submitting Data

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

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

15.6.3. All data to be submitted under the Schedule(s) must be submitted to SLDC / STU or to such other department and/or address 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.

15.6.4. 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.

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

15.7. Data not supplied

Users are obliged to supply data as referred to in the individual section of the Grid Code and listed out in the Data Registration Section Appendices. In case any data is missing and not supplied by any User, STU or SLDC may, acting reasonably, if and when necessary, estimates such data depending upon the urgency of the situation. Similarly in case any data is missing and 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.

15.8. 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.

15.9. Load-Flow Studies:

15.9.1. The STU shall carry out periodic Load-Flow studies of the network to facilitate future expansion and augmentation of the network. The studies should encompass both transient as well as Steady State studies.

15.9.2. The State Load Despatch Centre will also conduct Load-Flow studies for operation planning. Such studies shall be based on Historical as well as real time data.

15.9.3. The STU and SLDC shall take the requisite measures to enhance the capacity building measures for such studies so that the personnel engaged in planning and operation are adequately trained.

APPENDIX

APPENDIX A: STANDARD PLANNING DATA

Standard Planning Data consist of details, which are expected to be normally sufficient for STU to investigate the impact on the State Grid due to User development.

A. Standard planning data covering (a) preliminary project planning

Reference To: Section – 4: System Planning Section - 5Connection Condition

i. **Standard Planning Data** (Generation)

a. ***For SSGS – Thermal*** *(Coal / Gas/Fuel linked)*

Sl	*Item*	*Details to be provided*
General		
1	Site	Give location map to scale showing roads, railway lines, Transmission lines, canals, pondage and reservoirs if any.
2	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.
3	Water Sources	Give information on availability of water for operation of the Power Station
4	Environmental	States whether forest or other land areas are affected.
5	Site Map (To Scale)	Showing area required for Power Station coal linkage, coal yard, water pipe lines, ash disposal area, colony etc.
6	Approximate period of construction	
Connection		
1	Point of Connection	Give single line diagram of the proposed Connection with the system
2	Step up voltage for Connection (kV)	
Station Capacity		
1	Total Power Station capacity (MW)	State whether development will be carried out in phases and if so, furnish details
2	No. of units & unit size (MW)	
Generating Unit Data		
1	Steam Generating Unit	State type, capacity, steam pressure, stream temperature etc.
2	Steam turbine	State type, capacity.
3	Generator	Type Rating (MVA) Speed (RPM) Terminal voltage (kV) Rated Power Factor Reactive Power

Sl	*Item*	*Details to be provided*
		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
4	Generator Transformer	Type Rated capacity (MVA) Voltage Ratio (HV/LV) Tap change Range (+ % to - %) Percentage Impedance (Positive Sequence at Full load)
5	Steam Generating Unit	State type, capacity, steam pressure, stream temperature etc.

b. ***For SSGS – Hydro***

Sl	**Item**	**Details to be provided**
General		
1	Site	Give location map to scale showing roads, railway lines, and transmission lines.
2	Site map (To scale)	Showing proposed canal, reservoir area, water conductor system, fore-bay, power house etc.
3	Submerged Area	Give information on area submerged, villages submerged, submerged forest land, agricultural land etc
4	Whether storage type or run of river type	
5	Whether catchment receiving discharges from other reservoir or power plant.	
6	Full reservoir level	
7	Minimum draw down level.	
8	Tail race level	
9	Design Head	
10	Reservoir level v/s energy potential curve	
11	Restraint, if any, in water discharges	
12	Approximate period of construction.	
Connection		
1	Point of Connection	Give single line diagram proposed Connection with the Transmission System.

Sl	Item	Details to be provided
2	Step up voltage for Connection (kV)	
Station Capacity		
1	Total Power Station capacity (MW)	State whether development is carried out in phases and if so furnish details.
2	No. of units & unit size (MW)	
Generating Unit Data		
1	Operating Head (in Metres)	a. Maximum b. Minimum c. Average.
2	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
3	Turbine	State Type and capacity
4	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)
5	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).

ii. **Standard Planning Data** (Transmission)

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:

a. Name of line (Indicating Power Stations and substations to be connected).

b. Voltage of line (kV).

c. No. of circuits.
d. Route length (km).
e. Conductor sizes and Type.
f. Line parameters (PU values).
   1. Resistance/km
   2. Inductance/km
   3. Susceptance/ km (B/2)
g. Approximate power flow expected- MW & MVAr.
h. Terrain of the route- Give information regarding nature of terrain i.e. forest land, fallow land, agricultural and river basin, hill slope etc.
i. Route map (to scale) - Furnish topographical map showing the proposed route showing existing power lines and telecommunication lines.
j. Purpose of Connection- Reference to Scheme, wheeling to other States etc.
k. Approximate time for completion of Construction.

iii. **Standard Planning Data** (Distribution):

Sl	Item	Detail to be provide
General		
1	Area Map (to scale)	Marking the area in the map of Assam for which Distribution License is applied. .
2	Consumer Data	Furnish categories of consumers, their numbers and connected loads.
3	Reference to Electrical Divisions presently in charge of the Distribution.	
Connection		
1	Points of Connection	Furnish single line diagram showing points of Connection
2	Voltage of supply at points of Connection	
3	Names of Grid Sub-Station feeding the points of Connection	
Lines and Sub-stations		
1	Line Data	Furnish lengths of line and voltages within the Area.
2	Sub-station Data	Furnish details of 33/11kV sub-station, 11/0.4 kV sub- stations, capacitor installations
Loads		
1	Loads drawn at points of Connection.	
2	Details of loads fed at EHV, if any. Give name of consumer, voltage of supply, contract demand and name of Grid Sub-station from	

Sl	Item	Detail to be provide
	which line is drawn, length of EHV line from Grid Sub-station to consumer's premises.	
3	Reactive Power compensation installed	
Demand Data (for all Loads 1 MW and above)		
1	Type of load	State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads etc.
2	Rated voltage and phase	
3	Electrical loading of equipment	State number and size of motors, types of drive and control arrangements.
4	Power Factor	
5	Sensitivity of load to voltage and frequency of supply.	
6	Maximum Harmonic content of load.	
7	Average and maximum phase unbalance of load.	
8	Nearest sub-station from which load is to be fed.	
9	Location map to scale	Showing location of load with reference to lines and sub-stations in the vicinity.
Load Forecast data		
1	Peak load and energy forecast for each category of loads for each of the succeeding 5 years.	
2	Details of methodology and assumptions on which forecasts are based.	
3	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.	
4	Details of loads 1 MW and above.	• Name of prospective consumer. Location and nature of load/complex. • Sub-Station from which to be fed. • Voltage of supply. • Phasing of load.

APPENDIX B: DETAILED PLANNING DATA

Refer to:

Section-4: System Planning

Section-5: Connection Conditions

A. Detailed Planning Data (Generation) Part-I (for Routine Submission)

i. SSGS – Thermal

General

a. Name of Power Station.
b. Number and capacity of Generating Units (MVA).
c. Ratings of all major equipments (Boilers and major accessories, Turbines, Alternators, Generator Unit Transformers etc).
d. Single line Diagram of Power Station and switchyard.
e. Relaying and metering diagram.
f. Neutral Grounding of Generating Units.
g. Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors)
h. Earthing arrangements with earth resistance values.

Protection and Metering

a. 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).
b. Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, Tie circuit breakers, and incoming circuit breakers.
c. Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System.
d. Most probable fault clearance time for electrical faults on the User's System.
e. Full description of operational and commercial metering schemes.

Switchyard (In relation to interconnecting transformers):

a. Rated MVA.
b. Voltage Ratio.
c. Vector Group.
d. Positive sequence reactance for maximum, minimum, normal Tap.(% on MVA).
e. Positive sequence resistance for maximum, minimum, normal Tap.(% on MVA).
f. Zero sequence reactance (% on MVA).
g. Tap changer Range (+% to -%) and steps.
h. Type of Tap changer. (off/on load).

Switchyard (In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of Connection):

a. Rated voltage (kV).
b. Type of circuit breaker (MOCB/ABCB/SF6).
c. Rated short circuit breaking current (kA) 3 phase.

d. Rated short circuit breaking current (kA) 1 phase.
e. Rated short circuit making current (kA) 3 phase.
f. Rated short circuit making current (kA) 1-phase.
g. Provisions of auto reclosing with details.
h. Basic Insulation Level (kV) -
   i. Bus bar.
   ii. Switchgear.
   iii. Transformer bushings.
   iv. Transformer windings.

Parameters of Generating Units:

a. Rated terminal voltage (kV).
b. Rated MVA.
c. Rated MW.
d. Speed (rpm) or number of poles.
e. Inertia constant H (MWSec./MVA).
f. Short circuit ratio.
g. Direct axis synchronous reactance (% on MVA) Xd.
h. Direct axis (saturated) transient reactance (% on MVA) Xd'.
i. Direct axis (saturated) sub-transient reactance (% on MVA) Xd".
j. Quadrature axis synchronous reactance (% on MVA) Xq .
k. Quadrature axis (saturated) transient reactance (% on MVA) Xq'.
l. Quadrature axis (saturated) sub-transient reactance (% on MVA) Xq".
m. Direct axis transient open circuit time constant (Sec) $T'd_o$.
n. Direct axis sub-transient open circuit time constant (See) $T''d_o$.
o. Quadrature axis transient open circuit time constant (Sec) $T'q_o$.
p. Quadrature axis sub-transient open circuit time constant (Sec) $T''q_o$.
q. Stator Resistance (Ohm) R_a.
r. Neutral grounding details.
s. Stator leakage reactance (Ohm) X_1.
t. Stator time constant (Sec).
u. Rated Field current (A).
v. Open Circuit saturation characteristic for various terminal Voltages giving the compounding current to achieve the same.
w. MW and MVAr Capability curve

Parameters of excitation control system:

a. Type of Excitation.
b. Maximum Field Voltage.
c. Minimum Field Voltage.
d. Rated Field Voltage.

e. Details of excitation loop in block diagrams showing transfer functions of individual elements using I.E.E.E. symbols.
f. Dynamic characteristics of over -excitation limiter.
g. Dynamic characteristics of under-excitation limiter.

Parameters of governor:

a. Governor average gain (MW/Hz).
b. Speeder motor setting range.
c. Time constant of steam or fuel Governor valve.
d. Governor valve opening limits.
e. Governor valve rate limits.
f. Time constant of Turbine.
g. Governor block diagram showing transfer functions of individual elements using I.E.E.E. symbols.

Operational parameters:

a. Minimum notice required to synchronise a Generating Unit from de- synchronization.
b. Minimum time between synchronizing different Generating Units in a Power Station.
c. The minimum block load requirements on synchronizing.
d. Time required for synchronizing a Generating Unit for the following conditions:
    i. Hot
    ii. Warm
    iii. Cold
e. Maximum Generating Unit loading rates for the following conditions:
    i. Hot
    ii. Warm
    iii. Cold
f. Minimum load without oil support(MW).

General Status

a. Detailed Project report.
b. Status Report
    i. Land
    ii. Coal
    iii. Water
    iv. Environmental clearance
    v. Rehabilitation of displaced persons
    vi. Techno-economic approval by Central Electricity Authority (CEA).
    vii. Approval of State Government/Government of India.
    viii. Financial Tie-up.

Connection

a. Reports of Studies for parallel operation with the State Grid.
b. Short Circuit studies
c. Stability Studies.
d. Load Flow Studies.
e. Proposed Connection with the State Grid.
f. Voltage
g. No. of circuits
h. Point of Connection.

ii. SSGS – Hydro

General

a. Name of Power Station.
b. No and capacity of units. (MVA)
c. Ratings of all major equipment.
   i. Turbines (HP)
   ii. Generators (MVA)
   iii. Generator Transformers (MVA)
   iv. Auxiliary Transformers (MVA)
d. Single line diagram of Power Station and switchyard.
e. Relaying and metering diagram.
f. Neutral grounding of Generator.
g. Excitation control.
h. Earthing arrangements with earth resistance values.
i. Reservoir Data.
   i. Salient features
   ii. Type of Reservoir
   iii. Multipurpose
   iv. For Power
   v. Operating Table with
      – Area capacity curves and
      – Unit capability at different net heads

Protection

a. 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).
b. Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, tiebreakers, and incoming breakers.
c. Full description of inter-tripping of breakers at the point or points of Connection with the Transmission System.
d. Most Probable fault clearance time for electrical faults on the User's System.

Switchyard

Interconnecting transformers:

a. Rated MVA
b. Voltage Ratio
c. Vector Group
d. Positive sequence reactance for maximum, minimum and normal Tap.(% on MVA).
e. Positive sequence resistance for maximum, minimum and normal Tap.(% on MVA).
f. Zero sequence reactance (% on MVA)
g. Tap changer range (+% to -%) and steps.
h. Type of Tap changer (off/on load).
i. Neutral grounding details. (x)

Switchgear (including circuit breakers, Isolators on all circuits connected to the points of Connection).

a. Rated voltage (kV).
b. Type of Breaker (MOCB/ABCB/SF6).
c. Rated short circuit breaking current (kA) 3 phase.
d. Rated short circuit breaking current (kA) 1 phase.
e. Rated short circuit making current (kA) 3 phase.
f. Rated short circuit making current (kA) 1 phase.
g. Provisions of auto reclosing with details.

Communications

Details of Communications equipment installed at points of connections.

Basic Insulation Level (kV)

a. Bus bar.
b. Switchgear.
c. Transformer Bushings
d. Transformer windings.

Generating Units

Parameters of Generator

a. Rated terminal voltage (kV).
b. Rated MVA.
c. Rated MW.
d. Speed (rpm) or number of poles.
e. Inertia constant H (MWsec./MVA).
f. Short circuit ratio.
g. Direct axis synchronous reactance Xd (% on MVA).
h. Direct axis (saturated) transient reactance (% on MVA) X'd.
i. Direct axis (saturated) sub-transient reactance (% on MVA) X"d.
j. Quadrature axis synchronous reactance (% on MVA) Xq.
k. Quadrature axis (saturated) transient reactance (% on MVA) X'q.

l. Quadrature axis (saturated) sub-transient reactance (% on MVA) X"q.
m. Direct axis transient open circuit time constant (sec) $T'd_o$.
n. Direct axis sub-transient open circuit time constant (sec) $T''d_o$.
o. Quadrature axis transient open circuit time content (sec) $T'q_o$.
p. Quadrature axis transient open circuit time constant (sec) $T''q_o$.
q. Stator Resistance (Ohm) R_a.
r. Stator leakage reactance (Ohm) X_1.
s. Stator time constant (Sec).
t. Rated Field current (A).
u. Neutral grounding details
v. Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this.
w. Type of Turbine.
x. Operating Head (Metres)
y. Discharge with full gate opening (cumecs)
z. Speed Rise on total Load throw off(%).
aa. MW and MVAr Capability curve

Parameters of excitation control system:

As applicable to thermal Power Stations

Parameters of governor:

As applicable to thermal Power Station

Operational parameter:

a. Minimum notice required to Synchronise a Generating Unit from de- synchronisation.
b. Minimum time between Synchronising different Generating Units in a Power Station.
c. Minimum block load requirements on Synchronising.

General Status

a. Detailed Project Report.
b. Status Report.
c. Topographical survey
d. Geological survey
e. Land
f. Environmental Clearance
g. Rehabilitation of displaced persons.
h. Techno-economic approval by Central Electricity Authority.
i. Approval of State Government/Government of India.
j. Financial Tie-up.

Connection

a. Reports of Studies for parallel operation with the State Grid.
b. Short Circuit studies
c. Stability Studies.

d. Load Flow Studies.
e. Proposed Connection with the State Grid.
f. Voltage
g. No. of circuits
h. Point of Connection.

Reservoir Data

a. Dead Capacity
b. Live Capacity

iii. SSGS –Gas

General

a. Name of Power Station.
b. Number and capacity of Generating Units (MVA).
c. Ratings of all major equipments (Turbines, Alternators, Heat Recovery Boiler, Generator Unit Transformers etc)
d. Single line Diagram of Power Station and switchyard.
e. Relaying and metering diagram.
f. Neutral Grounding of Generating Units.
g. Excitation control- (What type is used? e.g. Thyristor, Fast Brushless Excitors)
h. Earthing arrangements with earth resistance values.
i. Start up Engine
j. Turbine Details

Protection and Metering

a. 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).
b. Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, Tie circuit breakers, and incoming circuit breakers.
c. Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System.
d. Most probable fault clearance time for electrical faults on the User's System.
e. Full description of operational and commercial metering schemes.

Switchyard (In relation to interconnecting transformers):

a. Rated MVA.
b. Voltage Ratio.
c. Vector Group.
d. Positive sequence reactance for maximum, minimum, normal Tap.(% on MVA).
e. Positive sequence resistance for maximum, minimum, normal Tap.(% on MVA).
f. Zero sequence reactance (% on MVA).
g. Tap changer Range (+% to -%) and steps.

h. Type of Tap changer. (off/on load).

Switchyard (In relation to switchgear including circuit breakers, isolators on all circuits connected to the points of Connection):

a. Rated voltage (kV).
b. Type of circuit breaker(MOCB/ABCB/SF6).
c. Rated short circuit breaking current (kA) 3 phase.
d. Rated short circuit breaking current (kA) 1 phase.
e. Rated short circuit making current (kA) 3 phase.
f. Rated short circuit making current (kA) 1-phase.
g. Provisions of auto reclosing with details.

Lightning Arresters -

Technical data Communication -

Details of communication equipment installed at points of connections.

Basic Insulation Level (kV) -

a. Bus bar.
b. Switchgear.
c. Transformer bushings.
d. Transformer windings.

Generating Units

a. Parameters of Generating Units:
b. Rated terminal voltage (kV).
c. Rated MVA.
d. Rated MW.
e. Speed (rpm) or number of poles.
f. Inertia constant H (MWSec./MVA).
g. Short circuit ratio.
h. Direct axis synchronous reactance (% on MVA) Xd.
i. Direct axis (saturated) transient reactance (% on MVA) Xd'.
j. Direct axis (saturated) sub-transient reactance (% on MVA) Xd".
k. Quadrature axis synchronous reactance (% on MVA)Xq .
l. Quadrature axis (saturated) transient reactance (% on MVA) Xq'.
m. Quadrature axis (saturated) sub-transient reactance (% on MVA) Xq".
n. Direct axis transient open circuit time constant (Sec) $T'd_o$.
o. Direct axis sub-transient open circuit time constant (Sec) $T"d_o$.
p. Quadrature axis transient open circuit time constant (Sec) $T'q_o$.
q. Quadrature axis sub-transient open circuit time constant (Sec) $T"q_o$.
r. Stator Resistance (Ohm) R_a.
s. Neutral grounding details.
t. Stator leakage reactance (Ohm) X_1.

u. Stator time constant (Sec).
v. Rated Field current (A).
w. Open Circuit saturation characteristic for various terminal Voltages giving the compounding current to achieve the same.
x. MW and MVAr Capability curve

Parameters of excitation control system:

a. Type of Excitation.
b. Maximum Field Voltage.
c. Minimum Field Voltage.
d. Rated Field Voltage.
e. Details of excitation loop in block diagrams showing transfer functions of individual elements using I.E.E.E. symbols.
f. Dynamic characteristics of over - excitation limiter.
g. Dynamic characteristics of under-excitation limiter.

Parameters of governor:

a. Governor average gain (MW/Hz).
b. Speeder motor setting range.
c. Time constant of steam or fuel Governor valve.
d. Governor valve opening limits.
e. Governor valve rate limits.
f. Time constant of Turbine.
g. Governor block diagram showing transfer functions of individual elements using I.E.E.E. symbols.

Operational parameters:

a. Minimum notice required synchronising a Generating Unit from de- synchronization.
b. Minimum time between synchronizing different Generating Units in a Power Station.
c. The minimum block load requirements on synchronizing.
d. Time required for synchronizing a Generating Unit for the following conditions:
    i. Hot
    ii. Warm
    iii. Cold
e. Maximum Generating Unit loading rates for the following conditions:
    i. Hot
    ii. Warm
    iii. Cold
f. Minimum load without oil support (MW).

General Status

a. Detailed Project report.
b. Status Report
c. Land

d. Gas/Liquid Fuel
e. Water
f. Environmental clearance
g. Rehabilitation of displaced persons
h. Approval of State Government/Government of India.
i. Financial Tie-up.

Connection

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

B. Detailed System Data (Transmission)- for STU and Transmission Licensees

General

a. Single line diagram of the Transmission System down to 33 kV bus at Grid Sub-station detailing:
b. Name of Sub-station.
c. Power Station connected.
d. Number and length of circuits.
e. Interconnecting transformers.
f. Sub-station bus layouts.
g. Power transformers.
h. Reactive compensation equipment.
i. Sub-station layout diagrams showing:
    i. Bus bar layouts.
    ii. Electrical circuitry, lines, cables, transformers, switchgear etc.
    iii. Phasing arrangements.
    iv. Earthing arrangements.
    v. Switching facilities and interlocking arrangements.
    vi. Operating voltages.
    vii. Numbering and nomenclature:
        – Transformers.
        – Circuits.
        – Circuit breakers.
        – Isolating switches.

Line Parameters (for all circuits)

a. Designation of Line.

b. Length of line (km).
c. Number of circuits.
d. Per Circuit values.
e. Operating voltage (kV).
f. Positive Phase sequence reactance (pu on 100 MVA) X_1
g. Positive Phase sequence resistance (pu on 100 MVA) R_1
h. Positive Phase sequence susceptance (pu on 100 MVA) B_1
i. Zero Phase sequence reactance (pu on 100 MVA) X_0
j. Zero Phase sequence resistance (pu on 100 MVA) R_0
k. Zero Phase sequence susceptance (pu on 100 MVA) B_0

Transformer Parameters (For all transformers)

a. Rated MVA
b. Voltage Ratio
c. Vector Group
d. Positive sequence reactance, maximum, minimum and normal (pu on 100 MVA) X_1
e. Positive sequence resistance, maximum, minimum and normal (pu on 100 MVA) R_1
f. Zero sequence reactance (pu on 100 MVA).
g. Tap change range (+% to -%) and steps.
h. Details of Tap changer. (Off/On load).

Equipment Details (For all substations)

a. Circuit Breakers
b. Isolating switches
c. Current Transformers
d. Potential Transformers

Relaying and Metering

a. Relay protection installed for all transformers and feeders along with their settings and level of co-ordination with other Users.
b. Metering Details.

System Studies

a. Load Flow studies (Peak and lean load for maximum hydro and maximum thermal generation).
b. Transient stability studies for three-phase fault in critical lines.
c. Dynamic Stability Studies
d. Short circuit studies (three-phase and single phase to earth)
e. Transmission and Distribution Losses in the Transmission System.

Demand Data (For all substations)

a. Demand Profile (Peak and lean load).

Reactive Compensation Equipment

a. Type of equipment (fixed or variable).
b. Capacities and/or Inductive rating or its operating range in MVAr.

c. Details of control.

d. Point of Connection to the System.

C. Detailed Planning Data (Distribution)

General

a. Distribution map (To scale). Showing all lines up to 11 kV and sub-stations belonging to the Supplier.

b. Single line diagram of Distribution System (showing distribution lines from points of Connection with the Transmission System, 33/11 kV substations, 11/0.4 kV substation, consumer bus if fed directly from the Transmission System).

c. Numbering and nomenclature of lines and sub-stations (Identified with feeding Grid sub-stations of the Transmission and concerned 33/11 kV substation of Supplier).

Connection

a. Points of Connection (Furnish details of existing arrangement of Connection).

b. Details of metering at points of Connection.

Loads

a. Connected load - Active and Reactive Load. Furnish consumer details, Number of Consumers category wise, details of loads 1 MW and above, power factor.

b. Information on diversity of load and coincidence factor.

c. Daily demand profile (current and forecast) on each 33/11 kV sub-station.

d. Cumulative demand profile of Distribution System (current & forecast).

APPENDIX C: OPERATIONAL PLANNING DATA

C-1: OUTAGE PLANNING DATA

REFER TO: SECTION-7-OUTAGE PLANNING

A. DEMAND ESTIMATES: For Distribution Company/Licensees

Item	Due date/ Time
Estimated aggregate annual sales of Energy in Million Units and peak and lean demand in MW & MVAr at each Connection point for the next financial year.	15th November of current year
Estimated aggregate monthly sales of Energy in million Units and peak and lean demand in MW & MVAr at each Connection point for the next month.	25th of current month
Hourly demand estimates for the day ahead.	10.00 Hours every day.

B. ESTIMATES OF LOADSHEDDING: For Distribution Company/Licensees

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. YEAR AHEAD OUTAGE PROGRAMME (For the financial year)

i. Generator Outage Program

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

ii. Year ahead NERPC Outage Programme (Affecting Intra-State Transmission System)

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

iii. ***Year ahead CPP's Outage Programme***

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

iv. Year Ahead Distribution Licensee: Outage Programme

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

v. STU's Overall Outage Programme

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

C-2: Generation Scheduling Data

REFER TO: SECTION 9: SCHEDULE AND DESPATCH

A. For SSGC:

Item	Due date/ Time
Day ahead hourly MW/MVAr availability (00.00 - 24.00 Hours) of SSGS.	09.00 hrs
Day ahead hourly MW import/export from CPP's.	09.00 hr
Status of Generating Unit Excitation AVR in service (Yes/No).	09.00 hr
Status of Generating Unit Speed Control System. Governor in service (Yes/No).	09.00 hr
Spinning reserve capability (MW).	09.00 hr
Backing down capability with/without oil support (MW).	09.00 hr
Hydro reservoir levels and restrictions.	09.00 hr
Generating Units hourly summation outputs (MW).	09.00 hr
Day ahead hourly MW entitlements from Central Sector Generation Power Stations from NERLDC.	10.00 hr

C-3: Capability Data

REFER TO: SECTION 10-FREQUENCY AND VOLTAGE MANAGEMENT

A. For SSGS

Item	
Generators and IPPs shall submit to STU up-to-date capability curves for all Generating Units.	On receipt of request from STU/ SLDC.
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.

C-4: Response to Frequency Change

REFER TO: SECTION 10 - FREQUENCY AND VOLTAGE MANAGEMENT

A. For SSGS

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 Assam Gridco/ SLDC
Secondary response in MW to frequency changes	On receipt of request from Assam Gridco/ SLDC

C-5: Monitoring of Generation

REFER TO: SECTION 11 MONITORING OF GENERATION AND DRAWAL

A. For SSGS

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

C-6: Essential and Non-essential load data

REFER TO: SECTION 12 CONTINGENCY PLANNING

A. For Discoms /Distribution Licensee

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: PROTECTION DATA

REFER TO: SECTION 14 - PROTECTION

Item	Due date/ Time
For SSGS	
Generators / CPPs / IPPs shall submit details of protection requirement and schemes installed by them as referred to in B-1. Detailed Planning Data under sub-section "Protection and Metering"	As applicable to Detailed Planning Data
For STU /Transmission Licensee	
The STU shall submit details of protection equipment and schemes installed by them as referred to in B-2. Detailed system Data, Transmission under sub-section "Relaying and Metering" in relation to Connection with any User.	As applicable to Detailed Planning Data

APPENDIX E: METERING DATA

REFER TO: SECTION – 15 METERING

Item	Due date/ Time
For SSGS	
SSGS shall submit details of metering equipment and scheme installed by them as referred in B-1. Detailed Planning Data under sub-section "Protection and Metering".	As applicable to Detailed Planning Data
For STU /Transmission Licensee	
STU shall submit details of metering equipment and schemes installed by them as referred in B-2. Detailed System Data, Transmission under sub-section "Relaying and Metering" in relation to Connection with any User.	As applicable to Detailed Planning Data

APPENDIX F: PLANNING STANDARDS

REFER TO: SECTION – 4 SYSTEM PLANNING

General Policy

The State Grid planning and generation expansion planning shall be in accordance with the provisions of the Planning Criterion as per IEGC Clause 3.5 as detailed below. However, some planning parameters of the Intra State transmission system may vary according to directives of AERC.

Planning Criterion

a. The planning criterion is based on the security philosophy on which ISTS and Intra State transmission system has been planned. The security philosophy shall be as per the Transmission Planning Criteria and other CEA guidelines. The general policy shall be as detailed below:

   i. As a general rule, the ISTS shall be capable of withstanding and secured against the following contingency outages without necessitating load shedding or rescheduling of generation during Steady State Operations:

      – Outage of a 132 kV D/C line or,
      – Outage of a 220 kV D/C line or,
      – Outage of a 400 kV S/C line or,
      – Outage of a single Interconnecting Transformer, or,
      – Outage of one pole of HVDC Bipole line, or,
      – Outage of a 765 kV S/C line.

   ii. The above contingencies shall be considered assuming a pre-contingency system depletion (Planned Outage) of another 220 kV D/C line or 400 kV S/C line in another corridor and not emanating from same sub-station. All the generating Units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified.

   iii. The ISTS/STS shall be capable of withstanding the loss of most severe single system in feed without loss of stability.

   iv. Any one of these events defined above shall notcause:

      – Loss of supply
      – Prolonged operation of the system frequency below and above specified limits
      – Unacceptable high or lowvoltage
      – System instability
      – Unacceptable overloading of ISTS/STS elements

APPENDIX G: SITE RESPONSIBILITY SCHEDULE

REFER TO: SECTION – 5 CONNECTION CONDITIONS

Name of Power Station/Sub-Station Site Owner:

Tel. Number: Fax Number:

Item of Plant/ Apparatus	Plant Owner	Safety Responsibility	Control Responsibility	Operation Responsibility	Maintenance Responsibility	Remarks
.....kV Switchyard						
All equipment including bus bars						
Feeders						
Generating Units						

APPENDIX H: INCIDENT REPORTING

REFER TO: SECTION – 14: OPERATIONAL EVENT /ACCIDENT REPORTING

FIRST REPORT..... Date: .....

Time: .....

	Date and time of incident	
	Location of incident	
	Type of incident	
	System parameters before the incident (Voltage, Frequency, Flows, Generation, etc.)	
	Relay indications received and performance of protection	
	Damage to equipment	
	Supplies interrupted and duration, if applicable	
	Amount of Generation lost, if applicable	
	Possibility of alternate supply arrangement	
	Estimate of time to return service	
	Cause of incident	
	Any other relevant information and remedial action taken	
	Recommendations for future improvement/repeat incident	
	Name of the Organisation	

(By order of Commission)

S. K. ROY,
Secretary,
Assam Electricity Regulatory Commission.

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