রেজিস্টার্ড নং ডি এ-১

বাংলাদেশ গেজেট

অতিরিক্ত সংখ্যা

কর্তৃপক্ষ কর্তৃক প্রকাশিত

রবিবার, মার্চ ৩, ২০২৪

[অর্থের বিনিময়ে জারীকৃত বিজ্ঞাপন ও নোটিশসমূহ]

Bangladesh Energy Regulatory Commission

Notification

Date : 22 Agrahayon, 1430 BS/07 December, 2023 AD

S.R.O. No.-336-Law/2023.—WHEREAS the Bangladesh Energy Regulatory Commission, hereinafter referred to as the Commission, in exercise of the power conferred by sub-section (3) of section 59 of the Bangladesh Energy Regulatory Commission Act, 2003 (Act No. 13 of 2003), hereinafter referred to as the said Act, has made pre-publication of the Notification S.R.O No-410-Law/2019 on January 9, 2020 and has requested all concerned to raise objection or give suggestion, if any, within 21 (twenty one) days from the date of such pre-publication; and

WHEREAS no objection or suggestion is received against this Notification;

NOW THEREFORE, the Commission, in exercise of the power conferred under sub-sections (1) and (2) of Section 59 of the said Act, is pleased to make the final publication of the following Regulations, namely:-

1. **Title and commencement.**— (1) These regulations may be called the Bangladesh Energy Regulatory Commission (Electricity Grid Code) Regulations, 2023.

   (2) It shall come into force at once.

2. **Definitions.**—In these regulations, unless there is anything repugnant in the subject or context,—

(a) "Grid Code" means the Electricity Grid Code, 2023 as annexed to the Schedule; and

(b) "Schedule" means the schedule of these regulations.

3. **Application.**—The Grid Code shall apply in the field of electricity transmission system planning, connection conditions, outage planning, schedule and dispatch, frequency and voltage management, contingency planning, cross boundary safety, operational event or accident reporting, protection, metering, communication and data acquisition, testing, numbering and nomenclature, data registration, performance standards for transmission, financial standards and all other matters relating to the electricity transmission system of Bangladesh.

BERC (Electricity Grid Code) Regulations, 2023

1. INTRODUCTION

1.1.1 Title:

The provisions contained in this document shall constitute and be collectively known and may be cited as the Electricity Grid Code, 2023, and will hereafter be called the Grid Code or Code.

1.1.2 General:

The Grid Code is a document that governs the boundary between the Licensee and Users and establishes procedures for the operations of facilities that will use the Transmission System. The Grid Code specifies criteria, guidelines, basic rules, procedures, responsibilities, standards, and obligations for the operation, maintenance, and development of the Electricity Transmission System of Bangladesh to ensure a transparent, non-discriminatory, and economic access and use of the Grid, whilst maintaining a safe, reliable, and efficient operation of the same to provide a quality and secure electricity supply as reasonably practicable.

It should be noted that the Grid Code is not concerned with the detailed design and operation of Power Stations and Distribution Systems, provided that their overall compatibility with the Transmission System needs is assured.

1.2 STRUCTURE OF THE GRID CODE

The Grid Code contains criteria and provisions in the following areas:

i. Management of the Grid Code: specifying the responsibilities of the Transmission Licensee (Licensee), the formation and functioning of the Grid Code Review Panel, and Grid Code review and revision;

ii. Planning: specifying the technical and design criteria and procedures to be applied by the Transmission Licensee (Licensee) in the planning, design, and development of the Transmission System and by other Users connected to or seeking Connection to the Transmission System;

iii. Connection: specifying the technical design criteria and standards to be complied with by the Licensee and other Users connected to or seeking Connection to the Transmission System;

iv. Outage: specifying the procedures relating to coordination of the Outages for scheduled maintenance of the Transmission System, Generating unit and Distribution System that will use the Transmission System;

v. Schedule and Dispatch: specifying the procedures to be followed by the System Operator, the Licensee and Users relating to the scheduling and dispatch of Generating Units to meet the electrical demand;

vi. Operations: specifying the conditions under which the Licensee, System Operator shall operate the Transmission System and other Users of the Transmission System shall operate their plant and/or systems for the generation and distribution of electricity in so far as necessary to protect the security and quality of supply and the safe operation of the Licensee’s Transmission System under both normal and abnormal operating conditions. Operation of the Grid generally covers:

Frequency and Voltage Management

Contingency Planning

Cross-Boundary Safety

Operational Event and Accident Reporting

Tests

Numbering and Nomenclature

Data Registration.

vii. Protection: specifying the coordination responsibility and minimum standards of protection that are required to be installed by Users of the Transmission System;

viii. Metering: specifying the minimum operational and commercial metering to be provided by the Single Buyer, the Licensee and Users, Communication requirements, Data acquisition;

ix. Performance Standard: specifying the technical standards, uniform accounting system, and financial standards and reporting indices in these respects to be implemented by the Licensee.

1.3 THEPURPOSE OF THIS CODE

(a) The operating procedures and principles governing Licensee's relationship with all Users are set out in the Grid Code.

(b) The Grid Code specifies procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

(c) This Code also sets out the technical requirements to be met by those who are connected to the Transmission System.

(d) It is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users as well as the Single Buyer in relation to the planning, operation, and use of the Transmission System.

(e) It seeks to avoid any undue discrimination between Users and categories of Users. It should be noted that the holder of the Transmission License is also defined as a User.

1.4 SCOPE

The Licensee shall comply with the Grid Code in its capacity as holder of the Transmission License and Generators, Distribution Utilities, and Bulk Power Consumers shall also comply with it as Users of the Transmission System in the course of their generation, distribution and utilization of electricity.

1.5 INTERPRETATION

1.5.1 The meaning of certain terms (which are printed in bold letters) used in the Grid Code shall be in accordance with the definitions listed in Section 2, “Definitions”, of the Grid Code.

1.5.2 Section 2 of this code has been developed on the premise that accepted engineering terms do not require additional definitions.

1.5.3 The term “**Grid Code**” means any or all parts of this document.

1.6 IMPLEMENTATION AND OPERATION OF THE GRID CODE

1.6.1 The Licensee has the duty to implement the Grid Code. All Users are required to comply with the Grid Code that will be enforced by the Licensee. Users must provide the Licensee reasonable rights of access, service and facilities necessary to discharge its responsibilities on the Users’ premises and to comply with instructions issued by the Licensee, reasonably required to implement and enforce the Grid Code.

1.6.2 If any User fails to comply with any provision of the Grid Code, it shall inform the Licensee without delay of the reason for its non-compliance and shall remedy its non-compliance promptly. Consistent failure to comply with the Grid Code may lead to Disconnection of the User’s plant and/or facilities to ensure Power System security. The Commission may impose appropriate sanctions, fines, or penalties in the case of such non-compliance.

1.6.3 The operation of the Grid Code will be reviewed regularly by the Grid Code Review Panel in accordance with the provisions of the relevant Section of the Grid Code.

1.7 GENERAL REQUIREMENTS

1.7.1 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.

1.7.2 Users must therefore understand and accept that the Licensee and the System Operator in such unforeseen circumstances, may be required to act decisively to discharge their obligations under its License. Users shall provide such reasonable cooperation and assistance as the Licensee and the System Operator may request in such circumstances.

1.8 CODE RESPONSIBILITIES

In discharging their duties under the Grid Code, the Licensee and the System Operator have to rely on information that other Users supply regarding their requirements and intentions. All required information must be made available to the Licensee and System Operator by Users with the utmost accuracy in order to help avoid or overcome abnormal operational circumstances.

1.9 CONFIDENTIALITY

Under the terms of the Grid Code, the Licensee and the System Operator will receive information from Users relating to their intentions in respect of their Generation, Distribution or Supply businesses. The Licensee 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.

1.10 PROCEDURES TO SETTLE DISPUTE

1.10.1 In the event of any conflict between any provision of the Grid Code and any contractor agreement between the Licensee and a User, the provision of the Grid Code will prevail.

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

1.11 COMMUNICATION BETWEEN THE LICENSEE AND USERS

1.11.1 All communications between the Licensee and Users shall be in accordance with the provisions of the relevant Section of the Grid Code.

1.11.2 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.

1.12 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.

1.13 DIRECTIVE

Under the provisions of Section 24 of the Act, the Government may issue policy directives on matters concerning electricity, including measures that are considered necessary for the overall planning and coordination of the development of the electricity sector. The Licensee shall promptly inform the Commission and all Users of the requirement of such a direction that affects the Grid Code. The Users shall comply with the directions.

1.14 MAINTENANCE

1.14.1 It is a requirement that all User's Plants and Apparatus on the Licensee's sites are maintained properly to ensure that they do not pose a threat to the safety of any of the Licensee's Plants, Apparatus or Personnel on the Licensee's site. The Licensee shall have the right to inspect test results and maintenance records relating to such Plant and Apparatus at any time.

1.14.2 It is also a requirement that all the Licensee's Plants and Apparatus on User's sites are maintained properly to ensure that they do not pose a threat to the safety of any User's Plants, Apparatus or Personnel on the User site. Users shall have the right to inspect test results and maintenance records relating to such Plants and Apparatus at any time.

1.15 CITIZEN CHARTER

The Licensee shall publish a Citizen Charter incorporating its obligations under the License issued by the Commission and the Grid Code.

2. DEFINITIONS AND ABBREVIATIONS

2.1 DEFINITIONS

Defined Term	Definition
Act	The Bangladesh Energy Regulatory Commission Act, 2003 (Act 13 of 2003).
Apparatus	Electrical Apparatus includes all machines, fittings, accessories, and appliances in which conductors are used.
Appendix	An Appendix to a Section of the Grid Code.
Area of Supply	The area within which alone a Distribution Utility is for the time being authorized, by his License to supply electricity.
Automatic Generation Control (AGC)	Automatic Generation Control (AGC) is a closed-loop control system to maintain system frequency by adjusting the base point economic allocation in response to small-scale changes in demand and to control tie-line power flow for meeting interchange schedule in cases where the power system is interconnected synchronously with other operating areas.
Back to Back	Back to Back is an interface substation where both a Rectifier and an Inverter are present for conversion and reconversion of AC and DC transmission.

Defined Term	Definition
BERC	Bangladesh Energy Regulatory Commission. Also known as the Commission. Established by the Bangladesh Energy Regulatory Commission Act of 2003.
Black Start	The process of recovery from a total or partial blackout of the Transmission System.
Bulk Power Consumer	A person or establishment to whom electricity is provided and who has a dedicated supply from the Grid at 132 kV or 230 kV.
Capability Curve	Boundaries of the P-Q characteristic area within which a Generating Unit can operate safely.
Check Metering System	The tariff Metering System is installed as a Back Up or Check Meter**.**
Connection	The electric lines and electrical equipment used to effect the Connection of a User's system to the Transmission System.
Connection Agreement	An agreement between the Licensee and a User setting out the terms relating to the Connection to and/or use of the Transmission System.
Connection Conditions	The technical conditions to be complied with by any User having a Connection to the Transmission System are laid down in Section 5: "Connection Conditions" of the Grid Code.
Connection Point	The point of Connection of the User system or equipment to the Grid.

Defined Term	**Definition**
Control Person	A person identified as having responsibility for cross-boundary safety under Section 10: "Cross Boundary Safety" of the Grid Code.
Conventional Generating Unit/ Plant	A Generating Unit or Plant that is not a Variable Renewable Energy Generating Unit or Plant or an energy storage unit.
Declared Available Capacity	The estimated net capacity of the Generating Units announced by the Generator that equals the Dependable Capacity less any reductions due to scheduled outages, forced outages or maintenance outages.
Detailed Planning Data	As referred to in the Data Registration Section.
Directive	A policy Directive issued by the Government of Bangladesh or the Commission under the provisions of the Act.
Disconnect	The act of physically separating a User's electrical equipment from the Transmission System.
Distribution Utility/ Distributor	An organization that is licensed to own and/or operate all or part of the Distribution System and is responsible for the supply of electricity.
Distribution System	The system of electric lines and electrical equipment owned and operated by a Distribution Utility.
Electricity Act, 2018	The Electricity Act was adopted in 2018 (Act 7 of 2018).
Electricity Rules, 2020	The Electricity Rules were formulated in 2020.

Defined Term	Definition
Energy Management System (EMS)	An Energy Management System (EMS) is a system of computer-aided tools used by the system operator to monitor, control, and optimize the performance of the generation and/or transmission systems.
Entity	Any Establishment, including the Single Buyer, Generator, Licensee, Distributor, System Operator, System Planner, and User, who uses the Transmission System and who must comply with the provisions of the Grid Code.
External Interconnection	Electric lines and electrical equipment used for the transmission of electricity between the Transmission System and any other Transmission System other than the Power System of Bangladesh.
Extra High Voltage or EHV	Nominal voltage levels of 132 kV and above.
Generating Unit	The combination of an alternator and a turbine set (whether steam, gas, water, or wind-driven) or a reciprocating engine or a PV Generating Unit and all of its associated equipment, which together represent a single electricity generating machine.
Generating Plant	A facility consisting of one or more Generating Units where electrical energy is produced from some other form of energy by means of suitable Apparatus.

Defined Term	Definition
Generator	An organization that has a License to generate electricity and is subject to the Grid Code.
Grid Code/ Code	The set of principles and guidelines is managed and serviced by the Licensee in accordance with the terms and conditions of the Transmission License and approved by the Commission.
Grid Code Review Panel/ Panel	The Panel was set up under Section 3: "Management of the Grid Code".
IPP	An Independent Power Producer is a Power Station owned by a Generator that sells power to a Single Buyer under a PPA signed according to the Private Sector Power Generation Policy of Bangladesh.
Licensee	The holder of the Transmission License for the bulk transmission of electricity between Generators and Distributors or Bulk Power Consumers.
Load Dispatch Centre (LDC)	The control centre operates round the clock for the purpose of managing the operation of the Transmission System and the coordination of generation and distribution on a real-time basis.
Merit Order	A way of ranking Generating Units based on ascending order of variable cost (fuel and variable O&M) to meet demand at the least cost.

Defined Term	Definition
Metering System	The tariff metering system is installed at the Connection Points in the Transmission System and owned by the Single Buyer.
National Load Dispatch Centre (NLDC)	Same as definition of LDC.
National Plan	The National Development Plan was prepared and produced by the Planning Commission.
Net Electrical Output	The net electrical energy, expressed in kW or kWh delivered to the Connection Point by the Generator.
Operating Committee	The committee, with members representing the Generator, the Single Buyer, the System Operator, and the Licensee, deals with all operational matters affecting the Transmission System and meets regularly.
Off Peak Period	That period in a day when electrical demand is the lowest.
Outage	The reduction of capacity or taking out of service of a Generating Unit, Power Station, or part of the Transmission System or Distribution System.
Peak Period	That period in a day when electrical demand is at its highest level.
Photovoltaic (PV)	A method of generating electrical energy by converting solar radiation into direct current electricity using semiconductors that directly produce electricity when exposed to light.

Defined Term	Definition
Photovoltaic Generating Plant	A Generating Plant is made up of one or more solar panels, a controller or inverter with or without a storage unit, and the interconnections and mounting for the other components, which are connected to the system at a single Connection Point.
Power Purchase Agreement or **PPA**	The agreement between a Generator and the Single Buyer in which, subject to certain conditions, the Single Buyer agrees to purchase the electrical output of the Generator's Generating Unit and the Generator agrees to provide services from this Unit.
Power Station	An installation of one or more Generating Units (even when sited separately) owned and/or operated by the same Generator and which may reasonably be considered to be managed as a single integrated generating complex.
Power System	The combination of the generation system, Transmission System and Distribution System.
Power System Master Plan (PSMP)	The Master plan for the Power System is reviewed and updated periodically, preferably every 5 years, covering all issues relating to the Power System.
Power System Stabilizer	A supplementary excitation controller is used to damp Generator electro-mechanical oscillations in order to stabilize the Grid.

Defined Term	Definition
Private Generator	A Generator that is not classified as a Public Sector Entity and operates as an IPP, rental or on any other basis under a PPA with the Single Buyer.
Public Sector Entities	The Bangladesh Power Development Board, the Bangladesh Rural Electrification Board constituted under the relevant Order, Ordinance and Act, or any other power sector entity owned by the Government.
Section	A Section or part of this Grid Code that is identified as covering a specific topic.
Single Buyer	An Entity in the public sector purchasing electricity from both public and Private Generators and selling it to Distributors or Bulk Power Consumers under Power Purchase and Power Sales Agreements, respectively. It may ultimately be responsible for the planning of least-cost generation expansion, the establishment of private power generating stations as per the generation expansion plan, and the operation of the Power System, including the economic dispatch of generation.
Standard Planning Data	As referred to in the Data Registration Section.

Defined Term	Definition
Supervisory Control and Data Acquisition / SCADA	SCADA refers to a centralized real-time control and monitoring system architecture that uses software and hardware elements where data collection functions are carried out from field the through a communications system, system data is monitored centrally, and control instructions are issued from the master station to all parts of the system. In Power System it is the combination of transducer (IED, RTU, PMU), communication links, and data processing systems that provides information to the NLDC and issues commands to the field on the operation of the generation, transmission, and distribution.
System Operator	The organization or department assigned to operate the Transmission System and Load Dispatch (presently NLDC).
System Planner	The organization or department assigned by the government for preparing Master Plan for the Power Sector (presently BPDB as Single Buyer).
Transmission License	The License granted to the Transmission Company by the Commission as per the provisions of the Act.

Defined Term	Definition
Transmission System (Grid)	The system of EHV electric lines and electrical equipment owned and/or operated by the Licensee for the purpose of the transmission of electricity between Power Stations, External Interconnections and the Distribution System, and Bulk Power Consumers.
User	A person or establishment, including the Licensee, the Single Buyer, the System Operator, Generator, Distribution Utility and Bulk Power Consumer who uses the Transmission System and who must comply with the provisions of the Grid Code.

2.2 ABBREVIATIONS

Term	Meaning
AACIR	Average Annual Customer Interruption Rate
ABCB	Air Blast Circuit Breaker
ACP	Average Collection Period
AFC	Automatic Frequency Control
AGC	Automatic Generation Control
AVR	Automatic Voltage Regulator
APSCL	Ashuganj Power Station Company Limited
B2B	Back to Back
BERC	Bangladesh Energy Regulatory Commission
BPDB	Bangladesh Power Development Board
BREB	Bangladesh Rural Electrification Board

Term	Meaning
CPGCBL	Coal Power Generation Company of Bangladesh Limited
DPDC	Dhaka Power Distribution Company Limited
DESCO	Dhaka Electricity Supply Company Limited
EBIT	Earnings Before Interest and Taxes
EGCB	Electricity Generation Company of Bangladesh Limited
EHV	Extra High Voltage
EMS	Energy Management System
FGMO	Free Governor Mode of Operation
HP	Horse Power
HV	High Voltage
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
Hz	Hertz
IEC	International Electro technical Commission
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent Power Producer
kA	Kilo ampere
kV	Kilo volt
kVAR	Kilo volt Ampere Reactive
kW	Kilo watt
kWh	Kilo watt hour
LDC	Load Dispatch Centre
mG	Milli-Gauss

Term	Meaning
MPEMR	Ministry of Power Energy and Mineral Resources
MOCB	Minimum Oil Circuit Breaker
mT	Milli-Tesla
MTBF	Mean Time Between Failures
MTTR	Mean Time To Repair
MW	Megawatt
MWh	Megawatt Hour
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
NESCO	Northern Electricity Supply Company Limited
NLDC	National Load Dispatch Centre
NWPGCL	North West Power Generation Company Limited
PBS	Palli Bidyut Samity
PGCB	Power Grid Company of Bangladesh Limited
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
RMS	Root Mean Square
ROA	Return on Assets
RPCL	Rural Power Company Limited
SCADA	Supervisory Control And Data Acquisition
SF6	Sulphur Hexafluoride
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
USoAC	Uniform System of Accounts
VRE	Variable Renewable Energy
WZPDCL	West Zone Power Distribution Company Limited

3. MANAGEMENT OF THE GRIDCODE

3.1 INTRODUCTION

The Licensee is required to implement and comply with the Grid Code and periodically review the same and its implementation. For the above purpose, a Grid Code Review Panel comprising representatives of all Users of the Transmission System shall be established.

Subject to the conditions in the next paragraph of this Section, a specific and important feature of the Grid Code is that no revision or modification of the Code, however large or small, may be made without being discussed at the Grid Code Review Panel meeting and approved by the Commission.

The Commission may issue directions requiring the Licensee to revise the Grid Code in such a manner as may be specified in those directions and the Licensee shall promptly comply with any such directions.

This document defines the procedure to be followed by the Licensee in maintaining the Grid Code and also in pursuing any change.

3.2 OBJECTIVE

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

3.3 RESPONSIBILITIES

3.3.1 The Licensee will be responsible for managing and servicing the Grid Code in order to discharge its obligations under the License.

3.3.2 The Licensee shall establish and service the requirements of the Grid Code Review Panel in accordance with the provisions of sub-section 3.4 of the Code.

3.4 GRID CODE REVIEW PANEL/ PANEL

3.4.1 The Grid Code Review Panel shall be maintained to undertake the following:

i. To keep and maintain the Grid Code and its workings under scrutiny and review.

ii. To analyze any major Grid disturbances soon after their occurrence and evolve any consequent revision to the Grid Code.

iii. To consider any proposal for amendment to the Grid Code that any User makes.

iv. To publish recommendations for changes to the Grid Code together with the reason for the change and any objections, if applicable.

v. To issue guidance on the interpretation and implementation of the Grid Code.

vi. To examine problems raised by Users.

3.4.2 The Panel shall be chaired by the Transmission Company in its capacity as the transmission Licensee and consist of the following members:

1. A Chairman from the Licensee not below the rank of Executive Director;
2. A Technical Member (Secretary) from the Licensee not below the rank of Chief Engineer;
3. A Technical Member from the System Operator or Planning Department of the Licensee.

Representatives from each of the following:

4. One Member to represent the Single Buyer;
5. One Member from BPDB to represent Generation;
6. One member from EGCB, NWPGCL, APSCL, RPCL, or CPGCBL (for tenure of one year each on a rotation basis);
7. One Member from IPPs or Private Generators (for tenure of one year each on a rotation basis to be notified by the Licensee, to represent all the IPPs or Private Generators in Bangladesh);
8. One Member from BPDB to represent Distribution;
9. One Member from BREB;
10. One Member from DPDC or DESCO (for tenure of one year each on a rotation basis);
11. One Member from WZPDCL or NESCO (for tenure of one year each on a rotation basis).

3.4.3 The Licensee will inform all Users of the names and addresses of the Panel Chairman and Technical Secretary at least seven days before the first Panel meeting and shall inform Users in writing of any subsequent changes.

3.4.4 Each User shall inform the Panel Technical Secretary of the name and designation of their Panel Representative not less than 3 working days before the first Panel meeting and shall inform the Panel Technical Secretary, in writing, of any subsequent change.

3.4.5 The Rules to be followed by the Panel in conducting their business shall be formulated by the Panel itself and approved by the Commission. The Panel will meet at least once every three months.

3.4.6 Sub-meetings may be held by the Licensee with a User to discuss individual requirements and with groups of Users to prepare proposals for the Panel meeting. The Panel may set up sub-committees for detailed studies of related problems.

3.5 GRID CODE REVIEW AND REVISIONS

3.5.1 The Technical Secretary shall present all proposed revisions of the Grid Code to the Panel for its consideration.

3.5.2 The Licensee shall send to the Commission following reports at the conclusion of each Review Meeting of the Panel.

(a) A report on the outcome of such a review.

(b) Any proposed revisions to the Grid Code that the Licensee reasonably thinks necessary for the achievement of the defined objectives.

(c) All written representations or objections from **Users** arising during the review.

3.5.3 All revisions to the Grid Code shall require the approval of the Commission. The Commission shall publish revisions to the Grid Code once approved by the Commission.

3.5.4 The Licensee shall present proposals to the Commission to allow relaxation, where Users have justified difficulties meeting the Grid Code requirements.

3.5.5 The revision number and date of issue shall appear on every page of the Grid Code.

3.5.6 Every change from the previous version shall be clearly marked in the margin. In addition, a revision sheet shall be placed at the front of the revised version that lists the number of every changed sub-Section, together with a brief description of the change.

3.5.7 The Licensee shall keep an up-to-date list of the recipients and locations of all serviced copies of the Grid Code.

4. TRANSMISSION SYSTEM PLANNING

4.1 INTRODUCTION

This Section specifies the technical and design criteria and procedures to be applied by the Licensee in the planning and development of the Transmission System. This section also identifies the method for data submissions by Users to the Licensee for the planning and development of the Transmission System.

A requirement for reinforcement or extension of the Transmission Systemmay arise for a number of reasons, including but not limited to the following:

i. Development in a User's system already connected to the Transmission System.

ii. The introduction of a new Connection Point between the User's system and the Transmission System.

iii. An increase in system capacity to remove operating constraints and maintain standards of security.

iv. Stability and Reliability considerations.

v. Cumulative effect of any of the above.

Accordingly, the reinforcement or extension of the Transmission System may involve work at an entry or exit point (Connection Point) of a Generator or Distribution Utility or Bulk Power Consumer to the Transmission System.

Since development of all Users' systems must be planned well in advance to permit consents and way leaves to be obtained and detailed engineering design or construction work to be completed, the Licensee will require information from Users and vice versa. To this effect, the Planning Code imposes a time scale for the exchange of necessary information between the Licensee and Users having regard, where appropriate, to the confidentiality of such information.

4.2 OBJECTIVE

The provisions of this Section are intended to enable the Licensee in consultation with the Single Buyer, Generators and Users, to provide an efficient, coordinated, secure, and economical Transmission System to satisfy future demand.

4.3 PERSPECTIVE PLAN

4.3.1 The System Planner will prepare and submit a long-term (preferably 20 years, which may be termed planning-term) Power System Master Plan to the Government and to the Commission for generation expansion and for Transmission System expansion to meet future demand.

4.3.2 For fulfillment of the above requirement, the System Planner and the Licensee shall work together to:

i. Forecast the demand for power within the Area of Supply in each of the succeeding planning terms and provide to the Commission details of the demand forecasts, data, methodology, and assumptions on which the forecasts are based.

ii. Prepare a least=cost generation plan for the Power System based on an analysis of primary fuel supply availability to meet the long-term load demand as per the forecast after examining the technical, economic, and environmental aspects of all available alternatives, taking into account the existing contracted generation resources and the effects of demand-side management.

iii. Prepare a long-term plan for the expansion of the Transmission System compatible with the above load forecast and generation plan.

iv. Combine the above elements to form the Power System Master Plan, which shall be reviewed yearly to identify any major changes or requirements or whenever the government urges urgent power generation, and communicated to the Commission.

4.3.3 The Power System Master Plan shall be updated periodically, preferably every 5 years, and used as an input to the national plan.

4.4 PLANNING AND SECUIRITY STANDARDS

The Transmission System shall be planned in accordance with the following transmission system planning and security standards.

Voltage limits:

Normal Operating Condition

±5% for 400 kV Bus

±6% for 230 kV and 132 kV Bus

Emergency Condition

±10 % for 400 kV Bus

+10/-15% for 230 kV and 132 kV Bus.

Transient voltage variation due to switching or tripping of transmission system equipment may exceed the above limit.

Minimum Contingency Criteria for Transmission Line Outages:

Single contingency of a permanent three-phase outage of any one circuit element or transformer.

Stability:

To be maintained stable during a fault clearance by a three-phase trip within 5 cycles and followed by successful reclosure within 50 cycles (1 sec dead time), provided the fault is not a permanent one.

4.5 PLANNING RESPONSIBILITY

4.5.1 The primary responsibility for load forecasting within its area rests with each of the Distribution Utilities. The Distribution Utilities shall determine peak load and energy forecasts for their respective areas for each category of loads for each of the succeeding planning terms and submit the same annually by March 31st to the Licensee and System Planner, along with details of the demand forecasts, data, methodology, and assumptions on which the forecasts are based. The load forecasts shall be made for each of the Connection Points between the Licensee and User and shall include annual peak load and energy projections and a daily load curve. The demand forecasts shall be updated annually or whenever major changes are made in the existing forecasts or planning. While indicating the requirements of single consumers with large demand~~s~~ (5 MW or higher), the Distribution Utility shall satisfy itself as to the degree of certainty of the demand materializing.

4.5.2 The Licensee and System Planner are responsible for integrating the load forecasts submitted by each of the Distribution Utilities and determining the long-term (20-years) load forecasts for the Power System. In doing so, the Licensee and System Planner may apply appropriate diversity factors and satisfy itself regarding the probability of materialization of bulk loads of consumers with demands above 5 MW in consultation with the Distribution Utility concerned.

4.5.3 The Licensee and System Planner may also review the methodology and assumptions used by the Distribution Utility in making the load forecast, in consultation with the Distribution Utility. The resulting overall load forecast will form the basis of planning for expansion of generation and the Transmission System.

4.6 PLANNING DATA REQUIREMENT

4.6.1 To assist the System Planner to discharge its responsibilities, the Licensee and the System Planner shall jointly conduct system studies and prepare perspective plans for the Transmission System as detailed in paragraph 4.3 of this Section. The Users shall furnish data to the Licensee and System Planner from time to time as detailed under the Data Registration Section and categorized as Planning Data (PD).

4.6.2 To enable Users to coordinate planning, design, and operation of their plants and systems with the Transmission System they may seek certain salient data of Transmission system as applicable to them, which the Licensee shall supply from time to time as detailed under the Data Registration Section and categorized as Detailed System Data (Transmission).

5. CONNECTION CONDITIONS

5.1 INTRODUCTION

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

5.2 OBJECTIVE

The objective of this Section is to ensure the following:

i. By specifying minimum 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.

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

iii. All Users or prospective Users are treated equitably.

iv. Specify the data required by the Licensee and System Operator from Users.

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

5.3 SITE RESPONSIBILITYSCHEDULE

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

i. The ownership of equipment.

ii. The responsibility for the control of equipment.

iii. The responsibility for the maintenance of equipment.

iv. The responsibility for the operation of equipment.

v. The manager of the site.

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

An illustrative Site Responsibility Schedule is provided in Appendix.

5.3.2 The User owning the Connection site shall provide reasonable access and other required facilities to another User whose equipment is installed at the Connection site for installation, operation, maintenance, etc.

5.4 SYSTEM PERFORMANCE

5.4.1 All equipment connected to the Transmission System shall be of such design and construction as to satisfy at least the requirements of the relevant Bangladesh Standard Specification, where no Standard exists, the appropriate IEC Standard or other International Standard will apply.

5.4.2 Installation of all electrical equipment shall comply with The Electricity Rules, 2020, and revisions thereof.

5.4.3 The Transmission System frequency shall normally be 50.0 Hz and shall normally be controlled in the range 49.5 – 50.5 Hz (50 Hz ± 1%). The User shall, however, be subject to the Grid discipline directed by the Commission.

5.4.4 Voltage variation on the Transmission System shall normally be ±5% for 400 kV, ±6% for 230 kV and 132 kV buses during normal operations, and ±10 % at 400 kV, + 10%-15% for 230 kVand 132 kV buses during emergencies in accordance with the provisions of the Planning and Security Standards for Transmission System.

5.4.5 Insulation coordination of the Users' equipment and rupturing capacity of switchgear shall conform to applicable Bangladesh Standards and Codes.

5.4.6 Protection schemes and Metering shall be as detailed in the Protection and Metering Sections of the Code.

5.4.7 For existing Power Stations, the equipment for communications (voice and data) and the SCADA and EMS systems shall be owned and maintained by the Licensee, unless alternative arrangements are mutually agreed upon. The Users shall be responsible for providing compatible SCADA, EMS, and Communication interfaces (Voice, Data and Tele-protection) with the System Operator's SCADA, EMS, and Communication systems for exchanging required system information and delivering control commands as stated in this Grid Code.

5.4.8 For new Power Stations or User's substations or facilities, the equipment within their site for communication (voice and data), SCADA Control (for example, RTU or SAS), and EMS interface shall be installed, owned, and maintained by the respective Generator or Bulk Power Consumer or other User.

5.5 CONNECTION POINT

5.5.1 Generator

5.5.1.1 Voltage may be 400 kV, 230 kV,or 132 kV or as agreed with the Single Buyer and the Licensee.

5.5.1.2 For new Power Stations or Connections

Unless specifically agreed with the Licensee and the Single Buyer, the Connection Point shall be at the outgoing gantry of Power Station switchyard. The metering point shall be at the outgoing Connection Point. All the substation equipment, including protection, control, and metering equipment, owned by the Generator within the perimeter of the Generator's site shall be maintained by the Generator. Other Users' equipment shall be maintained by the respective Users. From the outgoing feeder gantry onward, the Licensee shall maintain all electrical equipment.

5.5.1.3 For existing Power Stations

The existing arrangement for maintenance of all line bay equipment installed within the substation attached to the Power Station, viz. Circuit Breaker, Isolator, Lightning Arrester, Current Transformer, Voltage Transformer, etc., shall continue to be with the Generator. However, maintenance of line protection and communication equipment shall continue to be the responsibility of the Licensee as before.

5.5.2 Distribution Utility

5.5.2.1 Voltage may be 132 kV or 33 kV or as agreed with the Single Buyer and the Licensee.

5.5.2.2 The Connection and metering point of a Distribution Utility shall be at the outgoing 132 kV or 33 kV feeder gantry of the Licensee's Grid substation as agreed by the Licensee and the Single Buyer. The Licensee shall maintain all the terminal, communication, protection and metering equipment within the premises of the Licensee.

5.5.2.3 Provided that the metering point and Connection Point may be at the LV side of Grid Transformer when the LV bus and all the outgoing feeders are owned and utilized by a single Distribution Utility.

5.5.2.4 From the Connection Point onwards, the respective Distribution Utility shall maintain its electrical line and equipment.

5.5.2.5 Any disagreement or dispute in respect of Connection Point, metering point, and a portion of the common metering units shall be referred in writing to the Commission for settlement.

5.5.3 Bulk Power Consumers

5.5.3.1 Voltage may be 230 kVor 132 kV, or as agreed with the Single Buyer, Distribution Utility and Licensee.

5.5.3.2 The Connection and metering point shall be at the outgoing feeder gantry of the Licensee's Grid substation.

5.5.3.3 From the Connection Point onwards, Bulk Power Consumer shall maintain its own electrical equipment.

5.5.3.4 Substation at the consumer's electricity utilization premises shall be built, owned, and maintained by the Bulk Power Consumer in accordance with the design approved by the Licensee.

5.5.3.5 The Bulk Power Consumer's substation shall only be fed by a radial feeder from the nearest Grid substation.

5.5.3.6 To ensure Grid safety, transmission lines shall not be diverted to the consumer's substation, i.e., Line In and Line Out (LILO) shall not be permitted by the Licensee.

5.6 DATA REQUIREMENTS

Users shall provide the Licensee with data for this Section as specified in the Data Registration Section.

5.7 PROCEDURE FOR APPLICATIONS FOR CONNECTION TO AND USE OF THE TRANSMISSION SYSTEM

5.7.1 Any User seeking to establish new or modified arrangements for Connection to and/or use of the Transmission System shall submit the following report, data, and undertaking along with an application to the Licensee:

i. Power Purchase Agreement (PPA), or Power Sales Agreement (PSA), or other relevant Agreement with the Single Buyer.

ii. Report stating purpose and concurrence from the Single Buyer for the proposed Connection and/or modification, Connection site, description of Apparatus to be connected or modification to Apparatus already connected.

iii. Data as applicable and as listed in the Data Registration Section.

iv. Confirmation that the prospective installation complies with the provisions in the Electricity Act, 2018.

v. Construction schedule and target completion date.

vi. An undertaking that the User shall abide by the Grid Code and provisions of the Electricity Rules, 2020, and revisions thereof, for installation and operation of the Apparatus.

5.7.2 For every new Connection sought, the Licensee and the Single Buyer jointly shall specify the Connection Point and the voltage to be used, along with the metering, protection, communication, EMS, and SCADA requirements as specified in respective Sections.

5.7.3 The Licensee shall normally make a formal offer to the User within 2 months of receipt of the application, complete with all information as may reasonably be required, subject to the provision in paragraph 5.7.6.

5.7.4 The offer shall specify and take into account any works required for the extension or reinforcement of the Transmission System to satisfy the requirements of the Connection application and for obtaining statutory clearances and way leaves as necessary.

5.7.5 In respect of offers for modification of an existing Connection, the terms shall take into account the existing Connection Agreement.

5.7.6

i. If the nature of the complexity of the proposal is such that the prescribed time limit for making the offer is not adequate, the Licensee shall make a preliminary offer within the prescribed time limit. The offer shall indicate the extent of further time, required with the consent of the Commission for a more detailed examination of the issues.

ii. On receipt of the preliminary offer, the User shall promptly indicate whether the Licensee should proceed further to make a final offer within the extended time limit.

5.7.7 All offers (other than preliminary offers), including revised offers, shall remain valid for 60 days from the date of issue.

5.7.8 The Licensee shall make a revised offer upon request by a User, if necessitated by changes in data earlier furnished by the User.

5.7.9 In the event of the offer becoming invalid or not being accepted by any User within the validity period, no further action shall be taken by the Licensee on the Connection applications.

5.7.10 The Licensee may reject any application for Connection to and/or use of Transmission System:

i. If such a proposed Connection will violate any provisions of the Transmission Licensee.

ii. If the proposed works stated in the application do not lie within the purview of the Licensee or do not conform to any provision of the Grid Code.

iii. If the applicant fails to give confirmation and undertakings according to sub- Section 5.7.1 and 5.7.3.

5.8 REQUIREMENTS FOR CONVENTIONAL GENERATORS

5.8.1 Frequency Withstand Capability

The Generator shall ensure that each Generating Unit is capable of generating a full-rated power output within the frequency range of 49.5 to 50.5 Hz. Any decrease in power output occurring in the frequency range of 49.5 to 47.5 Hz shall not be more than the required proportionate value of the frequency decay.

Any variation of the system frequency within the range of 48.0 Hz to 51.5 Hz shall not cause the disconnection of the Generating Unit. The Generating Units shall be capable of operating, for at least 15 minutes in the case of an increase in frequency within the range of 51.5 to 52 Hz and for at least 30 minutes in the case of a decrease in frequency within the range of 48.0 to 47.5 Hz, in both cases provided the voltage at the Connection Point is within +/- 10% for 400 kV and +10/-15% for 230 kVand132 kV of the nominal value.

If the system frequency momentarily rises above 52.0 Hz or falls below 47.5 Hz, the Generation Unit shall remain in synchronism with the system for at least five (5) seconds. The System Operator may waive this requirement if there are sufficient technical reasons to justify the waiver.

5.8.2 Voltage Withstand Capability

The Generator shall ensure that each Generating Units capable of supplying its full rated power output (both active and reactive) within voltage variations within the range of +/- 5% for 400 kV and +/- 6% for 230 kV and 132 kV during normal operating conditions. Outside this range and up to a voltage variation of +/-10% for 400 kV and +10%/-15% for 230 kV and 132 kV, a reduction in active and/or Reactive Power is allowed, provided that this reduction does not exceed 5% of the Generator's declared data.

5.8.3 Reactive Power Capability and Control

The Generator shall ensure that each Generating Unit is capable of supplying its full rated Active Power output within the limits of lagging and leading power factor at the Generator terminals as mentioned in the PPA and in accordance with its Reactive Power Capability Curve.

The Generating Unit shall be capable of contributing to system voltage control by continuous regulation of the Reactive Power supplied to the Grid. For such reason, it shall be fitted with a continuously acting automatic excitation control system to control the terminal voltage without instability over the entire operating range of the Generating Unit.

The performance requirements for excitation control facilities, including eventual Power System Stabilizers, where necessary for appropriate Power System operations shall be specified in the Connection Agreement.

5.8.4 Speed-Governing System

The Generating Unit shall be capable of contributing to Frequency Control by continuous regulation of the Active Power supplied to the system. The Generating Unit shall be fitted with a fast-acting speed-governing system and FGMO to provide Frequency Control under normal operating conditions.

The speed-governing system shall have an overall speed-droop characteristic of five (5) percent or less. Unless waived by the System Operator, the speed-governing system shall be capable of accepting raise and lower signals from the control center of the System Operator.

5.8.5 Black Start Capability

The Power System shall have Black Start capability at a number of strategically located Generating Plants. The Generator shall specify in its application for a Connection Agreement if its Generating Unit has a Black Start capability.

5.9 REQUIREMENTS FOR VRE GENERATORS

5.9.1 Frequency Withstand Capability

The Generator shall assure that each VRE Generating Units capable of generating at maximum power output, depending on the availability of the primary resource, within the frequency range of 49.5 to 50.5 Hz.

The VRE Generating Unit shall be capable of continuously operating with any variation of the Power System frequency within the range of 48.0 Hz to 51.5 Hz. It shall also be capable of operating, for at least 5 minutes in the case of an increase in frequency within the range of 51.5 to 52 Hz and for at least 30 minutes in the case of a decrease in frequency within the range of 48.0 to 47.5 Hz, in both cases provided the voltage at the Connection Point is within +/- 10% for 400 kV and +10%/-15% for 230 kV and 132 kV of the nominal value. In case the frequency momentarily falls below 47.5 Hz, the VRE Generating Unit shall remain connected for at least 5 seconds. In the case of an increase in frequency above 52.0 Hz, the VRE Generator shall decide whether to disconnect the VRE Generating Plant and/or its Generating Units from the Grid.

5.9.2 Voltage Withstand Capability

The VRE Generating Units shall be capable of generating at maximum power output, depending on the availability of the primary resource and the interchange of Reactive Power at the Connection Point, as specified in paragraph 5.9.3,within the voltage variations within the standard limits for normal operating conditions. Outside this range and up to a voltage variation within standard limits for an emergency condition, a reduction in active and/or Reactive Power can be allowed, provided that this reduction does not exceed 5% of the Generator’s Declared Data.

5.9.3 Reactive Power Capability and Control

The VRE Generating Plant shall be capable of supplying Reactive Power output, at its Connection Point, within the following ranges:

(a) +/- 20 % of the Generating Plant capacity, as specified in the Generator's Declared Data, if the Active Power output, depending on the availability of the primary resource, is equal to or above 58% of the Generating Plant capacity;

(b) Any Reactive Power value within the limits of power factor 0.98 lagging to 0.98leading, if its Active Power output, depending on the availability of the primary resource, is within 10 % and 58% of the Generating Plant capacity;

(c) No Reactive Power interchange with the Grid if the Active Power output, depending on the availability of the primary resource, is equal to or less than 10% of the Generating Plant capacity.

The VRE Generating Plant shall be capable of contributing to voltage control by continuous regulation of the Reactive Power supplied to the Grid in any of the following modes, as it will be determined by the System Operator:

(a) Maintaining constant voltage at the Connection Point, at a set point instructed by the System Operator;

(b) Maintain an injection of Reactive Power, at the Connection Point, at a set point instructed by the System Operator;

(c) Maintaining a constant power factor of the injected Active Power at the Connection Point, at a value prescribed by the System Operator; or provided the limits of Reactive Power output established above are not exceeded.

In order to comply with these requirements, the VRE Generating Plant shall be equipped with an appropriate control system able to control voltage or Reactive Power interchange over the entire operating range, which shall not create oscillations in the Grid.

5.9.4 Active Power Control

VRE Generating Plants should be equipped with an Active Power regulation control system able to operate, at least, in the following control modes, provided that the system frequency is within the range 49 Hz – 51 Hz:

(a) Free Active Power production (no Active Power control): The VRE Generating Plant operates to produce maximum Active Power output, depending on the availability of the primary resource.

(b) Active Power constraint: The VRE Generating Plant shall operate producing Active Power output equal to a value specified by the System Operator (set-point), provided the availability of the primary resource is equal or higher than the prescribed value, or producing the maximum possible Active Power in case the primary resource availability is lower than the prescribed set-point;

In cases where the VRE Generating Plant operates in Active Power constraint mode, whenever any control parameter is changed, such change must be commenced within two seconds and completed not later than 30 seconds after receipt of an order to change any parameter. The accuracy of the control performed must be within ±2% of the entered value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

In case the system frequency exceeds 51.0 Hz, the Active Power control system should reduce the Active Power injected to the Grid previously according to the following formula:

$$\Delta P = 33 \cdot P_m \cdot \left(\frac{51.0 - f_n}{50} \right)$$

Where:

ΔP: is the variation in Active Power output that should be achieved

P_m: is the Active Power output before this control is activated

f_n: is the Grid frequency.

The reduction in Active Power output shall be performed at the maximum possible gradient, provided the technical capabilities of the VRE Generators are not exceeded. If the Active Power for any VRE Generating Plant is regulated downward below its minimum technical limit, shutting down of individual VRE Generating Units is allowed.

5.9.5 Performance During Grid Disturbances

The VRE Generating Plant shall be able to withstand voltage dips without disconnectionat the Connection Point, produced by faults or disturbances in the Grid, whose magnitude and duration profiles are within the shaded area in Figure 5.1. This area is defined by the following characteristics:

(a) If the voltage at the Connection Point falls to zero in any of the three phases, the Photovoltaic Generating Plant shall remain connected for at least 0.15 seconds;

(b) If the voltage at the Connection Point drops but it is still above 30% of the nominal value, in all three phases, the VRE Generating Plant shall remain connected for at least 0.60 seconds;

(c) If the voltage at the Connection Point is equal to or above 90% of the nominal value in all three phases, the VRE Generating Plant shall remain connected indefinitely, up to fault clearance;

(d) For voltages between 30% and 90% of the nominal value, the time the VRE Generating Plant shall remain connected shall be determined by linear interpolation between the following pairs of values: [voltage = 30%; time = 0.60 seconds] and [voltage = 90%; time = 3.0 seconds].

In the case of larger voltage deviations and/or lasting longer, the VRE Generating Plantis allowed to be disconnected from the Grid.

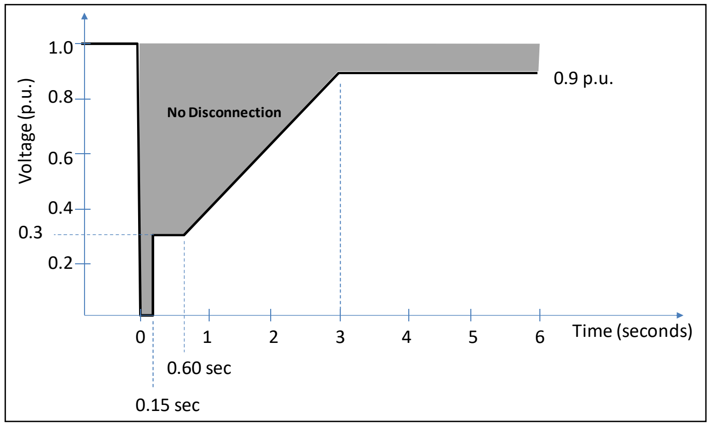

Figure 5.1: Low voltage withstand capability – VRE Generating Plant

In the case of three-phase faults on the Grid, at least the following performance should be achieved:

(a) Both during the time the fault exists in the Grid and during the voltage recovery period after fault elimination, there should be no Reactive Power consumption by the VRE Generating Plant at the Connection Point. Reactive Power consumption is only allowed during the first 150 milliseconds after the initiation of the fault and during the 150 milliseconds immediately after fault elimination, provided that during these periods the net consumption of Reactive Power by the VRE Generating Plant is not greater than 60% of the registered nominal capacity of the facility;

(b) Both during the time the fault exists in the Grid and during the voltage recovery period after fault elimination, there should be no consumption of Active Power by the VRE Generating Plant. Small consumptions of Active Power are allowed during the first 150 milliseconds immediately after the initiation of the fault and during the first 150 milliseconds immediately after the fault clearing.

(c) Both during the fault period and during the recovery period after the fault elimination, the VRE Generating Plant should inject into the system the maximum possible current (I_{total}). This injection of current shall be carried out in such a way that the operation of the facility is situated inside the shaded area of Figure 5.2 after 150 milliseconds from the initiation of the fault or the moment the fault has been eliminated.

In the case of unbalanced faults (single-phase faults and/or two-phase faults), at least the following performance should be achieved:

(a) Both during the fault period and the recovery period after fault elimination, there should be no Reactive Power consumption by the VRE Generating Plant at the Connection Point. Small amounts of Reactive Power consumption are allowed during the first 150 milliseconds immediately after the start of the fault and immediately after its elimination. In addition, transitory consumption is allowed during the fault period, provided that the following conditions are met:

- Net consumption of Reactive Power by the VRE Generating Plant shall not exceed an amount equivalent to 40% of the VRE Generating Plant installed capacity during any 100 millisecond period; and
- The Net consumption of reactive powerin each cycle (20 milliseconds) shall not exceed 40% of the VRE Generating Plant's installed capacity.

(b) Both during the period of existence of the fault and during the recovery period after fault elimination, there should be no consumption of Active Power by the VRE Generating Plant at the Connection Point. Transitory consumption of Active Power is allowed during the first 150 milliseconds after the initiation of the fault and the first 150 milliseconds after fault elimination.

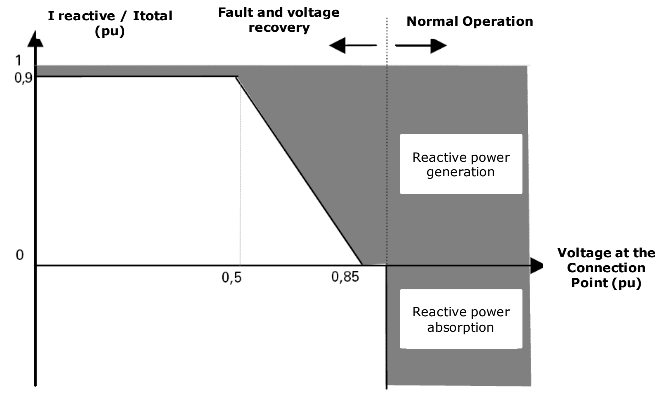

Figure 5.2: Allowed generation of Reactive Power during Voltage Dips

The VRE Generator shall demonstrate to the System Operator that the VRE Generating Plant complies with the above prescriptions through:

(a) A certification issued by the VRE Generating Units manufacturer stating that its VRE Generating Units have been tested and certified in a reputable laboratory, showing compliance with the stated requirements. A Copy of the laboratory certification shall be included.

(b) A formal declaration from the VRE Generator and/or its EPC Contractor indicating that the VRE Generating Plant's installed protection system and its settings, do not impair the performance required by this sub-Section.

5.10 REQUIREMENTS FOR DISTRIBUTORS AND OTHER GRID USERS

5.10.1 Determination of the Connection Point

The Distributor's , Bulk Power Consumer or other Grid User's equipment shall be connected to the Grid at the voltage level(s) agreed to by the Licensee, the Single Buyer and the Distributor (or Bulk Power Consumer or other Grid User) based on the studies performed by the Licensee.

5.10.2 Protection Arrangements

The Distributor's or other Grid User's equipment shall be connected to the Grid at the voltage level(s) agreed to by the Licensee and the Distributor (or other Grid User) based on the studies performed by the Licensee.

~~5.10.3~~ Reactive Power Compensation

Reactive Power Compensation and/or other facilities shall be provided by concerned Users as far as possible in the low-voltage systems close to the load points to avoid the need for exchange of Reactive Power to or from the Transmission System and to maintain Transmission System voltage within the specified range. Concerned Users shall ensure or maintain the load power factor as specified by the Commission at Connection Points by providing reactive compensation facilities at their network.

5.11 INTERNATIONAL AND INTER-REGIONAL CONNECTION

5.11.1 International and Inter-regional Connections will be:

(a) Synchronous; or

(b) Asynchronous.

5.11.2 The procedure for International Connection to the Grid and the execution of agreement for the same shall be done by the Licensee in consultation with the Single Buyer and the Line Ministry.

5.11.3 **HVDC** Transmission

5.11.3.1 Asynchronous Connection may be established by HVDC transmission having any of the following options:

(a) Rectifier at the sending end and Inverter at the receiving end

(b) **Back-to-Back** (B2B) with a Rectifier and Inverter at both ends.

5.11.3.2 HVDC transmission design and appropriate configuration of overhead and underground transmission Connections will be determined according to international standards. Configurations may be:

(a) Monopole with ground return

(b) Monopole with metallic return grounded at both ends

(c) Bipolar, opposite polarity, grounded neutral at both ends

(d) Bipolar, opposite polarity, with a metallic return conductor.

5.11.4 HVAC Asynchronous Connection

Asynchronous Connection may be established by HVAC transmission running up to a Back-to-Back (B2B) interface substation.

5.12 CONNECTION AGREEMENTS

A Connection Agreement shall include, as appropriate, within its terms and conditions the following:

i. A condition requiring both parties to comply with the Grid Code;

ii. Details of the Connection;

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

iv. A Site Responsibility Schedule;

5.13 APPENDIX

General format for the Site Responsibility Schedule.

APPENDIX

CONNECTION CONDITIONS

SITE RESPONSIBILITY SCHEDULE

Name of Power Station/Substation:............................

Site Owner:................................

Tel. Number:................................

Fax Number:................................

Item of Plant/ **Apparatus** 1	Plant Owner 2	Safety Responsibility 3	Control Responsibility 4	Operation Responsibility 5	Maintenance Responsibility 6	Remarks 7
.... kV Switchyard						
All equipment including busbar						
Feeders						

Name of Power Station/Substation:.............................

Site Owner:.................................

Tel. Number:................................

Fax Number:................................

Item of Plant/Apparatus 1	Plant Owner 2	Safety Responsibility 3	Control Responsibility 4	Operation Responsibility 5	Maintenance Responsibility 6	Remarks 7
Generating Units						

6. OUTAGE PLANNING

6.1 INTRODUCTION

This Section describes the process by which the Licensee carries out the planning of Transmission System Outages, including interface coordination with Users.

6.2 OBJECTIVE

The objective of this Section is to define the process that will allow the Licensee to optimize transmission Outages in coordination with Generator's and other Users' Outages while maintaining system security to the extent possible.

6.3 DEMAND ESTIMATION

6.3.1. Demand estimation is necessary both in the medium time scale to ensure adequate system plant margins and ratings and in the shorter time scale to assist with Frequency Control (see Schedule and Dispatch Section).

6.3.2. Distribution Utilities shall provide to the Licensee their estimates of demand at each Connection Point for the period from July to June by March 31st on a year-ahead, month-ahead, and day-ahead basis as required.

6.3.3. Based on this, the Licensee shall make monthly peak and off-peak period demand estimates for the year ahead, daily peak and off-peak period demand estimates for the month ahead, and hourly demand estimates for the day ahead.

6.3.4. Distribution Utilities shall provide to the Licensee estimates of theload that may be shed, when required, in discrete blocks with details of the arrangements for such load shedding.

6.3.5. All data shall be collected in accordance with procedures agreed upon between the Licensee and each User.

6.3.6. The Licensee shall maintain a database of demand on an hourly basis.

6.4 GENERATOR OPERATING COMMITTEES

6.4.1. The Licensee, the System Operator, the Single Buyer and the Generators shall establish Operating Committees, which shall serve as a point of coordination for the respective parties.

6.4.2. They shall meet at least once a month and establish the procedures relating to the operational interfaces between the parties. They shall include:

(a) The coordination of programs for testing and operation of the interconnections and associated transmission Grid system Apparatus, the Metering System, and the site;

(b) Incident coordination (i.e., force majeure events);

(c) Outage coordination;

(d) Generation Scheduling;

(e) Safety matters;

(f) Emergency Plans;

(g) Protection coordination;

(h) Frequency and voltage management;

(i) Black Start capabilities and procedures;

(j) Any other operational matters agreed upon by the Committees.

6.5 TRANSMISSION OUTAGE PLANNING PROCESS

6.5.1. The Licensee shall produce a yearly transmission Outage program for the period July to June.

6.5.2. All Generators shall provide the Licensee, the System Operator and the Single Buyer with their proposed Outage programs in writing for the year ahead (July to June) by March 31^{st} each year.

6.5.3. All Distribution Utilities shall provide the Licensee, the System Operator, and the Single Buyer with their proposed Outage programs in writing for the year ahead (July to June) by March 31^{st} each year.

6.5.4. Outage programs shall contain the identification of the unit (for Generating Units), the Outage start date, and the duration of the Outage.

6.5.5. The Licensee shall produce a draft Outage program based on the information received from Generators and Distribution Utilities, taking into account demand estimation and shall carry out studies as required each year.

6.5.6. The Licensee shall interact with all Users as necessary to review and optimize the draft plan, agree to any changes, and produce an acceptable coordinated generation and transmission Outage plan. The Licensee shall release the finally agreed transmission Outage plan, which takes account of User requirements, to all Users by May 31^{st} each year.

6.5.7. The Licensee shall review the final Outage plan monthly in consultation with Users, who shall be informed by the Licensee of any proposed changes.

6.5.8. Users' requests for additional Outages will be considered by the Licensee and accommodated to the extent possible.

6.5.9. The Licensee shall inform Users promptly of any changes that affect them.

6.6 RELEASE OF CIRCUITS AND GENERATOR UNITS INCLUDED IN OUTAGE PLAN

6.6.1. Notwithstanding provision in any approved Outage plan, no cross-boundary circuits or Generating Unit of a Generator shall be removed from service without specific release from the System Operator.

6.6.2. Once an Outage has commenced, if any delay in restoration is apprehended, the System Operator or User concerned shall inform the other party promptly, along with a revised estimation of restoration time.

6.7 DATA REQUIREMENTS

6.7.1. Users shall provide the Licensee with data for this Section as specified in the Data Registration Section.

7. SCHEDULE AND DISPATCH

7.1 INTRODUCTION

This section specifies the procedure to be adopted for the scheduling and merit order dispatch of Generating Units to meet system demand.

7.2 OBJECTIVE

The objective of this section is to detail the actions and responsibilities of the Licensee, the Single Buyer and the System Operator in preparing and issuing generation schedules as well as the responsibilities of Users to supply the necessary data and comply with those schedules.

7.3 GENERATION SCHEDULING

7.3.1 Yearly/ Monthly/ Weekly Schedules

7.3.1.1. The System Operator shall coordinate and prepare yearly, monthly, and weekly load-generation balance schedules and generation schedules.

7.3.1.2. The demand estimation for each case shall be made by the System Operator using the data made available by the Distribution Utilities and historical data maintained by the Licensee and the System Operator.

7.3.1.3. The System Operator shall prepare a yearly schedule of Net Electrical Output on a monthly basis, using the information from the dependable capacity of Generating Units, VRE generation forecasts, the yearly outage program, and estimated demands.

7.3.1.4. The Generator shall promptly inform the System Operator and the Single Buyer of any changes to any of the Net Electrical Output notifications.

7.3.1.5. The System Operator shall provide to the Licensee, Single Buyer and Generators yearly estimates of requirements for Net Electrical Output on a monthly basis for the year ahead (year-ahead notification) not less than 60 days before the beginning of each fiscal year. The Licensee in turn, submits the monthly estimates of Net Electrical Output requirements to the Commission.

7.3.1.6. The System Operator shall prepare a monthly schedule of generation on a day-by-day basis, using any Net Electrical Output changes provided by the Generator and estimated demands.

7.3.1.7. The System Operator shall provide to the Licensee, the Single Buyer and Generators monthly estimates of requirements for Net Electrical Output on a day by day basis for the month ahead (month-ahead notification), with provisional estimates for the following 2 months, not less than 14 days before the beginning of each month.

7.3.1.8. The System Operator shall prepare a weekly schedule of generation on an hourly basis, using any Net Electrical Output changes provided by the Generator and estimated demands.

7.3.1.9. The System Operator shall provide to the Licensee, the Single Buyer and Generators weekly estimates of requirements for Net Electrical Output on an hourly basis for the week ahead (week ahead notification), with provisional estimates for the following week,not less than 60 hours before the beginning of each week.

7.3.2 **Day Ahead Schedule**

7.3.2.1. The System Operator shall coordinate and prepare day-ahead schedules for generation.

7.3.2.2. All Generators shall provide the MW/ MVAR Declared Available Capacity (00.00 -24.00 hours) of all Generating Units to the System Operator during each hour of the day commencing 36 hours ahead and provisionally for the day immediately after (plant availability notification) by 12.00 hours.

7.3.2.3. VRE Generators shall provide forecasted production for the VRE Generation Unit’s hourly MW/MVAR availability to the System Operator.

7.3.2.4. In working out the MW/ MVAR availability, Hydro Power Stations shall take into account their respective reservoir levels and any other restrictions and report the same to the System Operator.

7.3.2.5. The Single Buyer shall prepare, update Merit Order of Generating Units and provide it to the System Operator.

7.3.2.6. After consolidation of the data provided by the Generators, the System Operator shall produce a day-ahead hourly generation schedule based on Merit Order of the Generating Units. It shall consist of availability, scheduled generation, allocated spinning reserve, and Generating Unit standby requirements. It shall also take into account the hourly demand estimates and the following:

Transmission System constraints

Hourly forecasts for VRE generations

Generating Units Schedule and Dispatch parameters

Requirements for voltage control

Allocated spinning reserve/ Operating reserve

7.3.2.7. The System Operator shall provide to the Licensee, the Single Buyer and Generators the generation schedule requirements for Net Electrical Output, start-ups, and Reactive Power on an hourly basis for that day, with provisional estimates for the following day, not less than 8 hours before the beginning of each day.

7.3.2.8. Generators shall promptly report to the System Operator and the Single Buyer, any changes in Generating Unit availability or capability or any unexpected situation that could affect their operation, including updated meteorological information that may affect VRE Generators production.

7.3.2.9. The System Operator shall advise Users as soon as possible of any necessary rescheduling.

7.3.2.10. The System Operator shall instruct Generators to hold capacity reserves (spinning and/or standby) according to the agreed Commission guidelines or as determined for local conditions. In normal operation, VRE Generators are exempt from providing spinning and/or standby reserves.

7.3.2.11. The System Operator may also require the Generators to generate MVAR within their respective capability limits to hold station busbar voltages at specified levels.

7.4 GENERATION DISPATCH

7.4.1. All Generators will be subject to dispatch instructions and shall regulate generation according to these instructions.

7.4.2. In the absence of any dispatch instructions by the System Operator, Generators shall generate according to the day-ahead generation schedule, or in the case of VRE Generators, according to the available primary resources.

7.4.3. Dispatch instructions shall be in standard format. These instructions will recognize declared availability, Merit Order and other parameters that have been made available by the Single Buyer and Generator to the System Operator. These instructions shall include time, Power Station, Generating Units, and the names of operators sending and receiving the same.

7.4.4. Dispatch instructions include, but are not limited to:

i. Switching a Generating Unit into or out of service.

ii. To increase or decrease MW generation from Generating Units, including VRE (subject to primary resource availability).

iii. Details of the reserve to be carried on a unit.

iv. To increase or decrease MVAR generation to assist with the voltage profile.

v. To begin pre-planned Black Start procedures.

vi. To hold spinning reserve.

vii. To hold Generating Units on standby.

7.4.5. The required spinning reserve of Generators shall be maintained to meet the performance standards of the system, except in conditions of shortfall in supply or operation restrictions. In case of any emergencies, the Generators shall be instructed by the System Operator to operate with a lower reserve margin. The System Operator shall promptly inform the Licensee, Single Buyer and Distribution Utilities about this matter in the most practicable way.

7.5 COMMUNICATION BETWEEN THE SYSTEM OPERATOR AND GENERATORS

Dispatch instructions or feedback from Generators shall be issued by e-mail, teleprinter, telephone, or computer-to-computer communication, confirmed by the exchange of names of operators sending and receiving the same and logging the same at each end. All oral instructions shall be complied with forthwith, and written confirmation shall be issued promptly by e-mail, fax, teleprinter or otherwise.

7.6 ACTION REQUIRED BY GENERATORS

7.6.1. All Generators shall comply promptly with a dispatch instruction issued by the System Operator unless this action would compromise the safety of the plant or personnel.

7.6.2. The Generator shall promptly inform the System Operator in the event of any unforeseen difficulties in carrying out an instruction.

7.6.3. Generators shall immediately inform the System Operator by telephone of any loss or change (temporary or otherwise) to the operational capability of any Generating Unit (including significant changes in VRE generation forecasts), which is synchronized to the system or which is being used to maintain system reserve. Generators shall inform the System Operator of any change in AVR and/or governor control mode of service with reasons.

7.6.4. Generators shall not de-synchronize Generating Units without instruction from the System Operator except on grounds of safety to plant or personnel, which shall be promptly reported to the System Operator.

7.6.5. Generators shall report any abnormal voltage and frequency-related operation of Generating Units/ feeders promptly to the System Operator.

7.6.6. Generators shall not synchronize Generating Units without instruction from the System Operator. In emergency situations, the Generator may synchronize Units with the Grid without prior intimation in the interest of the operation of the Grid following standing instructions developed for such purposes under “contingency planning”.

7.6.7. Should a Generator fail to comply with any of the above provisions, it shall promptly inform the System Operator of this failure.

7.6.8. The System Operator shall ensure that the Licensee and the Single Buyer is kept informed and up-to-date with all operation changes and deviations from the planned schedule.

7.7 DATA REQUIREMENTS

Users shall provide the System Operator with data for this section as specified in the Data Registration Section.

7.8 SHORTFALL MANAGEMENT

7.8.1 In preparing the day-ahead generation schedule and dispatch schedule, the System Operator shall consider the probable shortfall in generation, if any, and apportion the available generation among the entities by maintaining a definite principle approved by the Commission. The entities, in turn, manage the demand shortfall by imposing load shedding in a systematic and rational manner by maintaining a definite principle approved by the Commission.

7.8.2 The System Operator and Distribution Utilities shall always endeavor to restrict the net drawl at the Connection Point from the Grid within the drawl schedules whenever the system frequency is within normal operating limits. The concerned Distribution Utilities/ User shall ensure that their automatic demand management scheme ensures that there is no overdraw when frequency is 49.5 Hz or below. Distribution Utilities shall establish their own SCADA system to impose automatic load management in 11 kV feeders in case of shortfall.

8. FREQUENCY AND VOLTAGE MANAGEMENT

8.1 INTRODUCTION

This section describes the method by which all Users of the Transmission System shall cooperate with the Licensee in contributing towards effective control of the system frequency and managing the voltage profile of the Transmission System.

The System Operator has the overall responsibility of enforcing Grid discipline and managing the frequency of the Power System. The Users are required to follow the instructions of the System Operator for backing down generation, regulating load, etc. to meet the objective. The System Operator shall accordingly instruct Generating Units to regulate generation and export and hold reserves of Active and Reactive Power, within their respective declared parameters. The System Operator shall also regulate load as may be necessary to meet this objective.

The System Operator and the Licensee shall optimize voltage management by adjusting transformer taps to the extent available, and switching of circuits, reactors, capacitor banks and other operational steps. The System Operator will instruct Generating Units to regulate MVAR generation within their declared parameters. The System Operator shall also instruct Distribution Utilities to regulate demand if necessary.

The supply of quality power at the proper voltage and frequency is dependent on the active cooperation of Generators and Distribution Utilities as well as the fulfillment of individual user obligations in Transmission System.

8.2 OBJECTIVE

The objectives of this section are as follows:

i. To define the responsibilities of all Users in contributing to frequency management.

ii. To define the actions required to enable the Licensee to maintain Transmission System voltages and frequencies within acceptable levels in accordance with Commission directives, and planning and ecurity standards for Transmission System.

8.3 FREQUENCY MANAGEMENT

The normal frequency range will be 49.5 – 50.5Hz (50 Hz ±1.0%). The System Operator shall identify frequency deviations and take appropriate action to keep the frequency within the normal range.

8.3.1 Responsibilities

8.3.1.1 The System Operator shall monitor actual generation and load-generation balance and regulate generation and demand to maintain frequency within the prescribed limits.

8.3.1.2 The System Operator and the Licensee shall continuously monitor 400 kV/ 230 kV/ 132 kV transmission Grid line loadings on the Transmission System.

8.3.1.3 Generators shall follow the dispatch instructions issued by the System Operator.

8.3.1.4 All Generating Units shall have the governor available and in service and must be capable of automatic increases or decreases in output within the normal declared frequency range and within their respective capability limits.

8.3.1.5 Under certain conditions, the system frequency could rise to 52 Hz or fall to 47.5 Hz. All Generating Units should be capable of operating within the range according to clauses 5.8.1 and 5.9.1 and the System Operator should be promptly informed of any restrictions. Generators shall be responsible for protecting their Generating Units against damage should frequency excursions outside 52 Hz and 47.5 Hz ever occur. The Generator shall inform the System Operator immediately after taking such action.

8.3.1.6 Generators shall provide the following parameters of their Generating Units to the NLDC to ensure their participation in frequency and voltage regulations:

(a) Primary Frequency Control (*i.e*., Droop, Dead Band, Limiter, etc.);

(b) Secondary Frequency Control (the System Operator shall provide a list for AGC and EMS requirements);

(c) Tertiary Frequency Control (manual from the System Operator);

(d) Primary Voltage Control.

8.3.1.7 The Generating Units shall be designed to process the following capabilities:

(a) All Generating Units shall be frequency-sensitive.

(b) Power and Frequency Control of the Generating Units shall be achieved with a fast-acting prime mover Speed Governor.

(c) The governor shall have the capability to freely regulate the frequency with adjustable governor speed droop settings in the range of 2% to 3% for Hydro Turbines, 4% to 6% for GT and ST, and up to 10% for nuclear plants.

(d) Capable of responding automatically to normal variation in the system frequency.

(e) Governor dead band shall be within the range of ±0.05Hz. However, the governor shall respond to full frequency deviation once the system frequency deviation exceeds this specified dead band.

(f) Limiter (regulation range) setting shall be specified by the System Operator in collaboration with plants.

(g) If and when the Generating Unit is required to operate in an islanded mode, then the Governor Control System shall ensure that the islanded system will operate within the frequency range.

8.3.1.8 Distribution Utilities and Bulk Power Consumers shall cooperate with the System Operator in managing load on instructions from the NLDC as required.

8.3.1.9 The Licensee and the System Operator shall ensure that frequency and df/dt load shedding schemes are always functional.

8.3.1.10 Close coordination between Users and the NLDC shall exist at all times for the purposes of effective frequency and voltage management.

8.3.2 Sustained Rising Frequency

8.3.2.1 Under rising (from 50 Hz) frequency conditions, Generators having governor in service shall be capable of automatically decreasing output within the normal declared frequency range (49.5 Hz to 50.5 Hz) and within their respective limit (specified limiter or regulation range) in the mode of Primary Control or Free Governor Mode of Operation (FGMO).

8.3.2.2 The governors system of the plants running on FGMO shall be fitted with adjustable droop and shall have capability to operate with droop of 4% to 6% for thermal units & 2% to 3% for hydro units. The response (decrease of output) to a change (rising state) of system frequency shall be fully available within 10 seconds of the frequency change and be sustainable for a further 30 seconds.

8.3.2.3 The selected plants shall be capable of running in Automatic Generation Control (AGC/ LFC) Mode. Therefore, those plants shall automatically reduce output as per the AGC command(s) in secondary frequency regulation. Secondary response shall be fully available by 30 seconds from the time of frequency change to take over from primary response and shall be sustainable for a period of at least 30 minutes.

8.3.2.4 When the frequency rises above 50.5Hz, actions must be taken immediately by the Generators that are beyond the AFC. The System Operator shall take appropriate action to issue instructions to Generators to arrest the rising frequency and restore it within the normal range. Such instructions may include reducing generated output (*i.e.*, tertiary or manual control), de-synchronizing Generating Units or adding load to the system if there is any loadshed. Frequency up to 52.0Hz Generators shall have frequency withstand capability as mentioned in sub-Section 5.8.1.

8.3.2.5 Generators shall be responsible for protecting their Generating Units against damage should frequency excursions outside 52 Hz and 47.5 Hz ever occur.

8.3.3 Sustained Falling Frequency

8.3.3.1 Under falling (from 50 Hz) frequency conditions, Generators having governors in service shall be capable of automatically increasing output within the normal declared frequency range (49.5 Hz to 50.5 Hz) and within their respective limit (specified limiter or regulation range) in the mode of Primary Control or Free Governor Mode of Operation (FGMO).

8.3.3.2 The governor system of the plants running on FGMO shall be fitted with adjustable droop and shall have the capability to operate with droop of 4% to 6% for thermal units and 2% to 3% for hydro units. The response (increase of output) to a change (falling state) of system frequency shall be fully available within 10 seconds of the frequency change and be sustainable for a further 30 seconds.

8.3.3.3 The selected plants shall be capable of running in Automatic Generation Control (AGC/ LFC) Mode. Therefore, those plants shall automatically increase output as per the AGC command(s) in secondary frequency regulation. Secondary response shall be fully available by 30 seconds from the time of frequency change to take over from primary responses and shall be sustainable for a period of at least 30 minutes.

8.3.3.4 If the secondary control is insufficient, tertiary control operates to return frequency to the target value and restore the secondary control reserve. Tertiary frequency response is normally in the form of security-constrained economic dispatch.

8.3.3.5 When the frequency falls below 49.5 Hz, the System Operator shall take appropriate action to issue instructions to Generators to arrest the falling frequency and restore it within the normal range. Such instructions may include dispatch commands (*i.e.*, tertiary or manual control) or instructions to Generators to increase output or synchronize standby Generating Units to the Transmission System.

8.3.3.6 All Generating Units that have been declared available shall be required to be synchronized and loaded in the event of a sustained low frequency below 49.5 Hz, provided local and safety conditions permit. This action shall be performed without delay after failed attempts to contact the System Operator. The Generator shall inform the System Operator immediately after taking such action.

8.3.3.7 Distribution Utilities and Bulk Power Consumers should not increase load when the frequency is below 49.5 Hz.

8.3.3.8 When frequency falls below 49.35 Hz, the System Operator shall take appropriate action to issue instructions to Distribution Utilities to reduce load demand through appropriate manual and/or automatic load shedding.

8.3.3.9 When the frequency falls below 49.25, the System Operator shall impose SCADA operation to open the CB of outgoing feeders to the Distribution Utilities/ Bulk Consumers at Connection Points to stabilize the system frequency.

8.3.3.10 The System Operator shall be responsible for the coordination, selection among the feeders by rotation (provision for automatic), and settings of staged automatic relay-initiated under-frequency load shedding designed for system protection.

8.3.3.11 Frequency up to 47.5 Hz, the Generator shall have frequency withstand capability as mentioned in sub-Section 5.8.1.

8.4 VOLTAGE MANAGEMENT

8.4.1 The Licensee and the System Operator shall carry out load flow studies and perform voltage stability analysis 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 as specified in sub-section 4.4. On the basis of these studies, the System Operator shall instruct Generators to maintain specified voltage levels at their generation buses.

8.4.2 All Generating Units shall have Automatic Voltage Regulator (AVR) in service.

8.4.3 Generators shall inform the System Operator of their reactive reserve capability promptlyupon request.

8.4.4 Generators shall make available to the System Operator the up-to-date Capability Curves for all Generating Units, as detailed in Section 5, indicating any restrictions, to allow accurate system studies and effective operation of the Transmission System.

a. The System Operator and the Licensee shall continuously monitor 400 kVor 230 kVor 132 kV transmission Grid voltage levels at all Grid substations.

b. The System Operator and the Licensee shall regulate voltage levels within the prescribed range.

8.4.5 The System Operator and the Licensee shall jointly take appropriate measures to control Transmission System voltages, which may include but are limited to transformer tap changing and the use of MVAR reserves with Generating units within technical limits. These may include the operation of the following equipment:

(a) Synchronous Generating Units

(b) Synchronous Condenser

(c) Tap Changing Transformers

(d) Auto-Transformer Tap Changing

(e) Booster Transformers

(f) Shunt Capacitors and Reactors

(g) Static VAR Compensator (SVC)

(h) Static Compensator (STATCOM)

(i) Line Reactance Compensator (Series Cap)

(j) Flexible AC Transmission (FACT) Devices. etc.

8.4.6 The Licensee shall coordinate with the Distribution Utilities to determine voltage levels at the Connection Points.

8.4.7 The Distribution Utilities and Bulk Power Consumers shall maintain power factor within the range of 0.90 lagging and 0.95 leading at the Connection Point.

8.4.8 Distribution Utilities shall participate in voltage management by regulating their demand and changing tap positions on the 33/11 kV transformers as may be required.

8.5 MONITORING OF GENERATION

8.5.1 Available Capacity and Bus Voltage Monitoring

8.5.1.1 For effective operation of the Transmission System, it is important that a Generator's declared availability is realistic and that any departures are continually fed back to the Generator to help effect improvement. The monitoring by the System Operator of Generating Unit output and active and reactive reserve capacity shall be carried out to evaluate the reliability and performance of the plant.

8.5.1.2 The System Operator shall continuously monitor Generating Unit outputs and bus voltages. More stringent monitoring may be performed at any time, as detailed in the Testing Section, when there is reason to believe that a Generator's declared availability may not match the actual availability or that its declared output does not match the actual output.

8.5.1.3 Generators shall provide to the System Operator hourly generation summation outputs where no automatically transmitted metering or SCADA equipment exists.

8.5.1.4 The Generator shall provide other logged readings that the System Operator may reasonably require for monitoring purposes where SCADA data is not available.

8.5.2 Generating Unit Tripping

8.5.2.1 Generators shall promptly report the tripping of a Generating Unit, with reasons, to the System Operator in accordance with the Operational Event/ Accident Reporting Section. The System Operator shall keep a written log of all such tripps, including the reasons, with a view to demonstrating the effect on system performance and identifying the need for remedial measures.

8.5.2.2 Generators shall submit a more detailed report of all tripping and forced outages or shut downs of each Generating Unit to the System Operator monthly.

8.5.3 Data Requirements

Generators shall submit data to the System Operator as listed in the Data Registration Section, termed Frequency and Voltage Management.

9. CONTINGENCY PLANNING

9.1 INTRODUCTION

A contingency in the Transmission System may arise owing to generation deficiencies, inadvertent tripping of Transmission System components, failure of Transmission System equipment or operational errors. These may result in partial or total blackouts of the Grid.

This section describes the recovery process to be followed by the Licensee, the System Operator and all Users in the event of Transmission System total or partial blackouts.

9.2 **OBJECTIVE**

The objective of this section is to define a general guideline for the recovery process and responsibilities of all Users to achieve the fastest recovery in the event of a partial or total system blackout, taking into account essential loads, Generating Units capabilities and system constraints.

9.3 **STRATEGY**

9.3.1 The situation prevailing prior to the occurrence of the contingency, e.g., availability of specific Generators, transmission circuits, and load demands, will largely determine the restoration process to be adopted in the event of a total blackout. The System Operator shall advise all Users of the situation and follow the strategy outlined below for restoration.

9.3.2 **User's** persons authorized for operation and control shall be available at **User's** end for communication and acceptance of all operational communications throughout the contingency. Communication channels shall be restricted to operational communications only untill normality is restored.

9.4 **TOTAL SYSTEM BLACKOUT**

9.4.1 The System Operator shall instruct all relevant Generators having Power Stations with Black Start capability to commence their pre-planned Black Start procedure.

9.4.2 The System Operator shall prepare the Transmission System for restoration by creating discrete power islands with no interconnection. Close coordination with concerned Distribution Utilities shall be maintained during the restoration process to arrange for discrete demand blocks to becoming available to stabilize Generating Units, as they become available on individual islands.

9.4.3 Generators to whom start-up power supply is made available shall sequence their start-up to match their auxiliary power demand with the supply available.

9.4.4 Each discrete power island should contain at least one Black Start Generator capable of running in Isochronous Mode.

9.4.5 Generators shall inform the System Operator as Generating Units become available to take loadin order that the System Operator may assess the MW demand that the Generating Unit is likely to pick up on circuit breaker closure.

9.4.6 The System Operator shall coordinate with Generators and Distribution Utilities to:

(a) Form discrete power islands with one Generating Unit feeding some local demand.

(b) Extend islands by adding more Generating Units and more demand in a coordinated manner while maintaining load generation balance.

(c) Synchronize islands to form a larger, more stable island.

9.5 PARTIAL TRANSMISSION SYSTEM BLACKOUT

9.5.1 The System Operator shall ensure with the Licensee and Users that the security of the healthy part of the Transmission System is maintained.

9.5.2 The System Operator and the Licensee shall gradually extend the healthy system to provide start-up power to appropriate Generating Units.

9.5.3 The System Operator and the Licensee in close coordination with Distribution Utilities and Generators shall gradually restore demand to match generation as it becomes available.

9.5.4 All Users shall take care to ensure load-generation balance is maintained at all times under the System Operator's direction.

9.6 RESPONSIBILITIES

9.6.1 The Single Buyer shall ensure sufficient Black Start and Fast Start capability at strategic locations in the PPA with the selected Generators.

9.6.2 The System Operator shall maintain a record of Power Station Black Start capability and associated Power Station Black Start plans.

9.6.3 The System Operator shall prepare, distribute, and maintain up-to-date Black Start procedures covering the restoration of the Transmission System following total or partial blackout. Updated Black Start procedures shall be submitted to the Commission.

9.6.4 Users shall agree regarding Black Start procedures with the System Operator and the Licensee and promptly inform the System Operator when unable to follow the procedure.

9.6.5 The System Operator and the Licensee shall be responsible for directing the overall Transmission System restoration process in coordination with all Users.

9.6.6 Distribution Utilities shall be responsible for sectionalizing the Distribution System into discrete, unconnected blocks of demand. They shall advise the System Operator of the amount of MW likely to be picked up by the synchronizing Generator.

9.6.7 Generators shall be responsible for commencing their planned Black Start procedure on the instruction of the System Operator and steadily increasing their generation according to the demand that the System Operator is able to make available.

9.7 SPECIAL CONSIDERATIONS

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

9.7.2 A list of essential loads and priorities for restoration is shown in the Appendix. An updated list of essential loads and priorities for restoration shall be submitted to the Commission.

9.7.3 Distribution Utilities with essential loads shall separately identify non-essential components of such loads, which may be kept off during system contingencies.

9.7.4 Distribution Utilities shall draw up an appropriate schedule with corresponding load blocks in each case. The non-essential loads can be put on only when system normalcy is restored, as advised by the System Operator.

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

9.7.6 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 a subsequent investigation into the incident and the efficiency of the restoration process. Such an investigation shall be conducted promptly after the incident.

9.8 APPENDIX

Essential loads and the priority of restoration.

APPENDIX

CONTINGENCY PLANNING

ESSENTIAL LOADS AND PRIORITY OF RESTORATION

Priority	Type of Load	Name of Substation	Remarks

10. CROSS BOUNDARY SAFETY

10.1 INTRODUCTION

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

10.2 OBJECTIVE

The objective of this section is to achieve agreement and consistency on the principles of safety as prescribed in the Electricity Rules, 2020, and revisions thereto,as well as widely practiced international rules, with the concern of the Licensee when working across a control boundary between the Licensee and another User.

10.3 CONTROL PERSONS

The Licensee and all Users shall nominate suitably authorized persons to be responsible for the coordination of safety across their boundaries. These persons shall be referred to as Control Persons.

10.4 PROCEDURE

10.4.1 The Licensee shall issue a list of Control Persons (names, designations, and telephone numbers) to all Users who have a direct control boundary with the Licensee. This list shall be updated promptly whenever there is a change of in name, designation, or telephone number.

10.4.2 All Users with a direct control boundary with the Licensee shall issue a similar list of their Control Persons to the Licensee, which shall be updated promptly whenever there is a change to the Control Persons list.

10.4.3 Whenever work across a control boundary is to be carried out, the Control Person, of the User (which may be the Licensee), wishing to carry out the work shall directly contact the other relevant Control Person. Code words will be agreed upon at the time of work to ensure correct identification of both parties.

10.4.4 Contact between the Control Persons shall normally be by direct telephone. Should the work extend over more than one shift, the Control Person shall ensure that the relief Control Person is fully briefed on the nature of the work and the code words in operation.

10.4.5 The Control Persons shall cooperate to establish and maintain the precautions necessary for the required work to be carried out in a safe manner. Both the established isolation and the established earth shall be locked in position, where such facilities exist, and shall be clearly identified.

10.4.6 Work shall not commence until the Control Person, of the User (which may be the Licensee), wishing to carry out the work, is satisfied that all the safety precautions have been established. This Control Person shall issue agreed-upon safety documentation to the working party to allow work to commence.

10.4.7 When work is completed and safety precautions are no longer required, the Control Person who has been responsible for the work being carried out shall make direct contact with the other Control Person to request the removal of those safety precautions.

10.4.8 The equipment shall only be considered suitable for return to service when all safety precautions are confirmed as removed by direct communication using code word contact between the two Control Persons, and the return of agreed safety documentation from the working party has taken place.

10.4.9 The Licensee, Generators and Distribution Utilities shall jointly develop an agreed-upon written procedure for cross-boundary safety and continually update it.

10.4.10 Any dispute concerning crossbBoundary Safety shall be resolved at an appropriate higher level of authority.

10.5 SPECIAL CONSIDERATIONS

10.5.1 For cross boundary circuits all Users shall comply with the agreed safety rules, which must be in accordance with the Electricity Rules, 2020 and revisions thereof, and widely practiced international rules.

10.5.2 All equipment on cross-boundary circuits that may be used for the purpose of safety coordination and the establishment of isolation and earthing shall be permanently and clearly marked with an identification number or name, that number or name being unique in that substation. This equipment shall be regularly inspected and maintained in accordance the with manufacturer's specifications.

10.5.3 Each Control Person shall maintain a legibly written safety log, in chronological order, of all operations and messages relating to safety coordination sent and received by themselves. All safety logs shall be retained for a period of not less than 10 years.

11. OPERATIONAL EVENT/ ACCIDENT REPORTING

11.1 INTRODUCTION

This section describes the requirements for reporting, in writing, incidents that were initially reported orally by or to other Users.

11.2 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 on the Transmission System.

11.3 REPORTABLE INCIDENTS

Typical examples of reportable incidents that could affect the Transmission System are the following:

i. Exceptionally high or low system voltage or frequency;

ii. Serious equipment problem, e.g., major circuit, transformer, or bus barfault;

iii. Loss of a major Generating Unit;

iv. Falling of a transmission line or tower due to a natural calamity;

v. System split, Transmission System break away, or black out;

vi. Major fire incidents;

vii. Major failure of protection;

viii. Accidents;

ix. Equipment and transmission line overload;

x. Minor equipment alarms.

The last two reportable incidents are typical examples of those that are of lesser consequence but still affect the Transmission System and can be reasonably classified as minor. They will require corrective action but may not warrant management reporting until a later, more reasonable time.

11.4 REPORTING PROCEDURE

11.4.1.

i. All reportable incidents occurring in lines and equipment of 33 kV and above at Grid substations shall promptly be reported orally by the User whose equipment has experienced the incident (The Reporting User) to any other significantly affected Users and to the System Operator who shall immediately inform the Licensee.

ii. Within 1 (one) hour of being informed by the Reporting User, the System Operator or the Licensee may ask for a written report on any incident.

iii. If the reporting incident cannot be classified as minor, then the Reporting User shall submit an initial written report within two hours of being asked for one by the System Operator. This has to be further followed up by the submission of a comprehensive report within 48 hours of the initial written report.

iv. In other cases, the Reporting User shall submit a report within 5 (five) working days to the System Operator.

v. The System Operator shall immediately communicate all oral or written reportable incidents to the Licensee.

11.4.2 The System Operator or the Licensee may call for a report from any User on any reportable incident affecting other Users and the Licensee in case the same is not reported by such a User whose equipment might have been the source of the reportable incident.

The above shall not relieve any User from the obligation to report events in accordance with prevailing laws and regulations.

The format of such a report will be as agreed at the Grid Code Review Panel, but it will typically contain the following information:

i. Location of the incident;
ii. Date and time of the incident;
iii. Plant or equipment involved;
iv. Supplies interrupted and duration, if applicable;
v. Amount of generation lost, if applicable;
vi. Brief description of the incident;
vii. Estimate of time to return to service;
viii. Name of the originator;
ix. Action taken to overcome the situation.

11.5 REPORTING FORM

The standard reporting form, other than for accidents, shall be as agreed from time to time by the Grid Code Review Panel. When such a form has been agreed upon in Grid Code Review Panel meeting, it will be included as an Appendix in this Section of the Grid Code. The accepted form is to be numbered and included in the ISO/ Quality form of the users, where applicable.

11.6 MAJOR FAILURE

Following a major failure, the Licensee and other Users shall cooperate to inquire into and establish the cause of such failure and produce appropriate recommendations. The Licensee shall report the major failure to the Commission immediately for information and shall submit the inquiry report to the Commission within 2 (two) months of the incident.

11.7 ACCIDENT REPORTING

In both fatal and non-fatal accidents, the report shall be sent to the concerned authorities according to Section 29 of the Electricity Act, 2018 and to the Commission in the prescribed form.

APPENDIX

INCIDENT REPORTING

FIRST REPORT__________________ **Date :....................**

Time :...................

Date and time of the incident

Location of the incident :

Type of incident :

System parameters before the incident :

(Voltage, Frequency, Flows, Generation, etc.)

System parameters after the incident :

Network configuration before the incident :

Relay indications received and performance of protection :

Damage to equipment :

Supplies interrupted and duration, :

if applicable

Amount of Generation lost, :

if applicable

Estimate of time to return service :

Cause of the incident :

Any other relevant information and remedial action taken :

Recommendations for future improvement or repeat incident :

Name of the Organization :

12. PROTECTION

12.1 INTRODUCTION

In order to safeguard a User's system from faults that may occur on another User's system, it is essential that certain minimum standards of protection be adopted. This section describes these minimum standards.

12.2 OBJECTIVE

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

12.3 GENERAL PRINCIPLES

No item of electrical equipment shall be allowed to remain connected to the Transmission System unless it is covered by appropriate protection aimed at reliability, selectivity, speed, and sensitivity. Guidelines mentioned in protection manuals may be kept in mind.

All Users shall cooperate with the Licensee to ensure correct and appropriate settings of protection to achieve effective ,non-discriminatory removal of faulty equipment within the time for target clearance specified in this Section.

Protection settings shall not be altered, bypassed or or disconnected without the consultation and agreement of all affected Users. In the case where protection is bypassed and/or disconnected, by agreement, 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 immediatly.

Generator personnel shall not work upon or alter busbar protection, mesh corner protection, circuit breaker fail protection, or AC or DC wiring (other than power supplies or DC tripping associated with the Generating Unit itself) in the absence of a representative of the Licensee. Protection and relay settings shall be coordinated across Connection Point to ensure effective disconnection of faulty apparatus.

12.4 PROTECTION COORDINATION

The Licensee shall be responsible for arranging periodic meetings between all Users to discuss coordination of protection. The Licensee shall investigate any malfunction of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection malfunction or issue as discussed and agreed to in these periodic meetings.

The Licensee shall be responsible for carrying out any required system studies to determine the necessary protection and discrimination settings.

12.5 FAULT CLEARANCE TIMES

From a stability standpoint, the maximum fault clearance times for faults on any User's system directly connected to the Transmission System, or any faults on the Transmission System itself are as follows:

Target Clearance Times:

i.	400kV& Above	:	80 ms
ii.	230kV	:	100 ms
iii.	132kV	:	120 ms
iv.	33kV	:	300 ms

12.6 GENERATOR REQUIREMENTS

12.6.1 All Generating Units and all associated electrical equipment of the Generator connected to the Transmission System shall be protected by adequate and coordinated protection so that the Transmission System does not suffer due to any disturbance originating from the Generating Unit.

12.6.2 In the event of failure of the protection systems provided to meet the requirements of fault clearance detailed above, backup protection shall be provided by the Generator with a fault clearance time not slower than 400 ms for faults on the Generating Unit's HV Connections.

12.6.3 The Generating Unit's shall remain stable for external faults and tripping in the Transmission System. However, the generator tripping time for external faults in the Transmission System shall not be less than 1.6 seconds.

12.6.4 The protection shall also cover EHV lines and transformers to the same standards as for Transmission System and busbar protection, circuit breaker failure, pole slipping, loss of excitation, Power System Stabilizer, and negative phase sequence tripping.

12.6.5 Busbar Protection shall be provided and maintained by the Generators for each generation bus and substation bus owned by the Generators.

12.7 TRANSMISSION LINE REQUIREMENTS

Every EHV line taking off from a Power Station or a substation shall have main protection and backup protection as mentioned below. The Licensee shall notify Users of any changes in its policy on protection from time to time. Protection panels for the protection of lines of the Licensee taking off from a Power Station/substation shall be owned and maintained by the Licensee. Power Station or substation shall provide adequate space, Connection facilities, and access to the Licensee for such purposes.

The Generating units shall ensure that all common facilities needed for installing the required protective relaying are made available to the Licensee.

The Requirement of Reactive Power compensation devices shall be considered as per the system study, and an appropriate protection scheme shall be incorporated accordingly.

12.7.1 Transmission line (Overhead/Underground) of 230 kV and 400 kV

Two distance/line differential protections (depending upon line length) plus directional Earthfault function (in a directional comparison scheme) shall be provided as the Main-1 and Main-2 protections, respectively. One stand-alone 3-phase directional over-current or 2-phas eover-current plus one earth fault with a directional feature shall provide the backup protection. Main-1 and Main-2 protection shall be distance or line differential protection recommended by Licensee based on the system study. Main-1 and Main-2 protection relays shall be from two different manufacturers if the same type of protection is applied to Main-1 and Main-2.Three-pole and/or single-pole single-shot auto-reclosing equipment shall be fitted, as appropriate, as considered by the Licensee. All auto-reclosing equipment will be made inoperative for two=phase trip-out and/or back-up protection operations except for Directional Earth Fault with carrier-aided schemes. Both Distance and Directional Earth-fault functions shall have a compatible Communication-Aided Transfer Trip Scheme.

12.7.2 Transmission line (Overhead/Underground) of 132 kV

One distance/line differential protection (depending upon line length) plus directional earth-fault protection (in a directional comparison scheme) shall be provided as the main protection. One stand-alone 3-phase directional over-current or 2-phase Over-current plus one earthfault with a directional feature shall provide the backup protection. The Main protection shall be distance or differential protection recommended by Licensee based on the system study. Three-pole and/or single-pole single shot auto-reclosing equipment shall be fitted, as appropriate, as considered by the Licensee. All auto-reclosing equipment will be made inoperative for 2-phase trip-out and/or backup protections operation except Directional Earth Faults with carrier-aided schemes. Both Distance and Directional Earth-fault functions shall have a compatible Communication=Aided Transfer Trip Scheme.

12.8 DISTRIBUTION LINE REQUIREMENTS

All 132 kV and 230 kV lines, not owned by the Licensee, at Connection Points shall have the same protection requirements as for the Transmission Line requirements under Sections 12.7.1 and 12.7.2.

All 33 kV lines at Connection Points shall be provided with a minimum of overcurrent and earth-fault protection, with or without directional features as given below.

12.8.1 Non-Parallel Radial Feeders

Non-directional time lag Over-current and Earth-fault relays with a high set instantaneous element and suitable settings to obtain discrimination between adjacent relay stations.

12.8.2 Parallel Feeders/ Ring Feeders

Directional time lag Over-current and Earth-fault relays with a high set instantaneous element with suitable settings to obtain selectivity and coordination.

12.8.3 Long Feeders/ Transformer Feeders

For long feeders or transformer feeders, the relays should incorporate a high-set instantaneous element along with the time-lag over-current and earth-fault relays.

12.9 TRANSFORMER REQUIREMENTS

12.9.1 Generating Station/ Transmission System

All windings of auto-transformers and power transformers of the EHV class shall be protected by two dedicated differential relays and REF relays as main protection. Differential and REF protection shall be either in one relay or in separate relays. Main-1 and Main-2 protection relays shall be from two different manufacturers. In addition, there shall be one backup time-lag 3-phase over-current and earth-fault protection relay for each winding, as appropriate as considered by the respective authority. For parallel operation, such backup protection shall have a directional feature. For protection against heavy short circuits, the over-current and earth-fault relays should incorporate a high-set instantaneous element. There shall be standby Earth-fault protection as a backup for an uncleared earth fault on the STAR winding. In addition to electrical protection, gas-operated relays, winding temperature protection, and oil temperature protection shall be provided. Overvoltage, thermal overload, and overfluxing protection should also be provided.

12.9.2 Distribution System

For smaller transformers of HV class in a regular-type sub-station on the Distribution System differential protection shall be provided for 10 MVA and above, along with backup time lag over-current and earth-fault protection (with a directional feature for parallel operations). Transformers 1.6 MVA and above and less than 10 MVA shall be protected by time-lag over-current, earth-fault and instantaneous REF relays. In addition, all transformers 1.6 MVA and above shall be provided with gas-operated relays, temperature protection, winding temperature protection, and oil temperature protection.

12.10 SUBSTATION BUSBAR AND FIRE PROTECTION

12.10.1 All **Users** shall provide adequate bus zone protection incorporated with Breaker Failure Protection (BFP) for busbars in all 400 kV, 230 kV, and 132 kV class substations.

For 132 kV levels,one busbar protection system shall be implemented, and for 230 kV and 400 kV levels, redundant (Main-1 and Main-2) busbar protection systems shall be implemented. Main-1 and Main-2 bus bar protection systems shall be from two different manufacturers. Main-1 and Main-2 bus bar Differential Protection shall be from two different cores of CT/ CTs with dedicated relays and trip schemes. During expansion of any substation, integration into the busbar protection system shall have to be done by the owner of the new feeders with the necessary engineering work and hardware.

12.10.2 Adequate precautions shall be taken and protection shall be provided against fire hazards to all Apparatus of the Users conforming to relevant Bangladesh Standard Specification and/or provisions in the Electricity Rules, 2020 and amendments thereof and other standard engineering practices.

12.11 DATA REQUIREMENTS

Users shall provide the Licensee with data for this Section as specified in the Data Registration Section.

13. METERING, COMMUNICATION AND DATA ACQUISITION

13.1 INTRODUCTION

This Section specifies the minimum operational and commercial metering, communication, and data acquisition requirements to be provided by each User at the Connection Points and also at the cross-boundary circuits.

13.2 OBJECTIVE

The objective of this Section is to define the minimum acceptable metering and communication, and data acquisition requirements to enable the Licensee to manage the Transmission System in a safe and economic manner consistent with License requirements.

13.3 GENERATION OPERATIONAL METERING

13.3.1 This sub-section specifies the facilities that shall be provided for the practices that shall be employed for monitoring the output and response of Power Stations and Generating Units.

13.3.2 The Generator shall install operational metering to the Licensee's and Single Buyer's specifications so as to provide operational information for both real-time and recording purposes in relation to each Generating Unit at each Power Station in respect of:

- *i.* Bus Voltage
- *ii.* Frequency
- *iii.* MW
- *iv.* MWhr
- *v.* MVAR
- *vi.* MVARhr
- *vii.* MVA
- *viii.* Power Factor
- *ix.* Any other additional data as agreed between the Licensee, the Single Buyer and Generator.

13.3.3 All current transformers and voltage transformers used in conjunction with operational metering shall conform to relevant Bangladesh Standard Specifications or the relevant IEC, be of accuracy class 0.2s, and be of suitable rating to cater to the meters and the lead wire burdens. All new or replacement current and voltage transformers shall be of accuracy class 0.2s and 0.2s respectively. The Overall accuracy of the Metering System shall be within 0.2%. In case of failure to achieve the accuracy of individual equipment or the overall accuracy limit, a correction factor will be applied to calculate the correct energy.

13.3.4 Metering shall be calibrated so as to achieve overall accuracy of operational metering within the limits agreed between the Licensee and Generator. All new Metering Systems shall provide an overall measured accuracy of +/-0.2%.Records of calibration shall be maintained for reference and made available to the Licensee upon request.

13.3.5 Generators shall furnish recorded data of all electrical measurements and events recorded by the operational metering to the Licensee daily or as agreed between the Licensee and the Generator.

13.4 TRANSMISSION SYSTEM OPERATIONAL METERING

13.4.1 This sub-Section specifies the facilities that shall be provided for practices that shall be employed for monitoring electrical supply and load characteristic at each substation.

13.4.2 The Licensee shall install operational metering so as to provide operational information for both real-time and recording purposes in relation to each feeder, transformer, and compensation device at each substation in respect of:

i. BusVoltage
ii. Frequency
iii. MW
iv. MWhr
v. MVAR
vi. MVARhr
vii. MVA
viii. Power Factor
ix. Current
x. Any other additional data as agreed between the Licensee, the Single Buyer and Generator.

13.4.3 All current transformers and voltage transformers used in conjunction with operational metering shall conform to relevant Bangladesh Standard Specifications or the relevant **IEC**, be of accuracy class 0.2s for CT and 0.2 for VT and be of suitable rating to cater to the meters and the lead wire burdens. All new or replacement current and voltage transformers shall be of accuracy class 0.2. The accuracy class should be maintained strictly for new or replacement current and voltage transformers.

13.4.4 The Licensee shall furnish such data of all electrical measurements and events recorded by the operational metering to the Generator as required on request or as agreed between the Licensee and the Generator.

13.5 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

13.5.1 The System Operator and the Licensee shall install and make operationl an operational metering data collection system under SCADA for storage, display, and processing of metering data. For Generators, Distribution Utilities, Bulk Consumers and other Users, the equipment within their site for communication (voice and data), and SCADA control (for example, RTU/ Gateways) shall be installed, owned, and maintained by the respective Users.-

13.5.2 Necessary data shall be collected or acquired,; stored and real-time data is to be displayed at the NLDC.

13.5.3 The responsibilities for SCADA are detailed in the Metering, Communication and Data Acquisition Section.

13.6 COMMERCIAL (TARIFF) METERING

13.6.1 This sub-section specifies the provision of commercial (tariff) metering at Connection Points between the Transmission System and Generating Stations, and the Transmission System and Distribution Systems. It also specifies metering facilities that shall be provided for the measurement of electricity produced by Generating Units and for the measurement of electricity consumed at Power Stations.

13.6.2 Metering shall be installed to measure:

(a) Active energy for export

(b) Active energy for import

(c) Reactive energy for import

(d) Reactive energy for export

(e) Av Voltage

(f) Av frequency

(g) Reactive Energy while voltage >106%

(h) Reactive Energy while voltage >94%

13.6.3 At each commercial metering point associated with the determination of energy exported or imported, the Single Buyer shall install, own, and maintain (with the assistance of the Licensee) a metering system defined as the Metering System, and Check Metering System.

13.6.4 The Generator or Distribution Utility/ Bulk Power Consumer mayinstall, own, and maintain a metering system on their premises or substations.

13.6.5 Minimum standard of accuracy of meters shall be of class 0.2S or as agreed between the Single Buyer and the User and shall conform to the relevant Bangladesh Standard Specification or relevant IEC.

13.6.6 All current transformers and voltage transformers used in conjunction with commercial (Tariff) metering shall conform to the relevant Bangladesh Standard Specification or relevant IEC. The accuracy class of current transformers shall be 0.2S, and the accuracy class of voltage transformers shall be 0.2 S. The Burden rating of CTs and VTs must be suitable to cater to the meter and lead wire burdens.

13.6.7 The Metering System and the Check Metering System shall be designed and installed based on Prudent Utility Practices, providing a measured accuracy of +/-0.2% or as agreed between the Single Buyer and the User.

13.6.8 Data collection shall be used to integrate impulses from meters over each integration period as per agreement, store values, and transmit values to the data collection system of the Single Buyer. Data shall be collected from the Metering System.

13.6.9 Voltage supply to the metering shall be assured with the necessary voltage selection schemes. Voltage failure relays or the internal voltage monitoring feature of the Tariff Meter shall be provided, which will initiate alarm on the loss of one or more phases of the voltage supply to any meter.

13.6.10 The Single Buyer shall ensure that the testing and calibration of the Metering System and Check Metering System are carried out at intervals after 5 years, along with periodic yearly testing of the meter and associated equipment. The Single Buyer shall give no less than fifteen days notice to the User according to guidelines provided in the relevant Bangladesh Standard Specification or relevant IEC, as applicable. Records of the meter calibration test shall be maintained for future reference. The User may, at any time, request to inspect the test results and/or request a test if the User suspects the meter is incorrect.

13.6.11 The Single Buyer and the User shall jointly seal the Metering System and the Check Metering System. The Single Buyer shall break the seals only after giving at least twenty-four (24) hours notice, except under emergency conditions. The User may attend the breaking of the seals if considered necessary by the User.

13.6.12 Any dispute arising between the parties that cannot be resolved between the parties shall be referred to the Commission with all supporting documentation for a decision.

13.7 COMMUNICATION

Independent dedicated communication links such as microwave, PLC, Optical Fiber, etc. for voice communication, written communication, and data acquisition shall be installed between all Power Stations, substations, other User's premises, and the NLDC.

The Licensee, the System Operator and Generators are authorized to tape record all telephoned voice communications relating to Declared Available Capacity control and schedule, and dispatch and shall supply at the request of the other party a copy or transcript of any such recording.

The Licensee, the System Operator and Users are authorized to tape record all cross-boundary safety communications and shall supply, at the request of the other party, a copy or transcript of any such recording.

13.8 DATA ACQUISITION & CONTROL

13.8.1 For effective control of the Transmission System, the System Operator needs real-time data as follows:

i. Voltage, Current Flow, Real & Reactive power of transmission lines, Generators, Grid transformers, and distribution feeders;

ii. Voltage and frequency of all buses;

iii. Digital status and control of all switching devices;

iv. Status and control of Grid transformers;

v. All necessary alarms;

vi. All necessary signals and controls for EMS including AGC;

vii. Digital status and control of at least 50% load shed feeders;

viii. Wind Speed and directions at each Wind Generation Plant;

ix. Solar irradiations at each PV Plant;

x. Necessary weather data.

13.8.2 The Licensee shall provide and install all the facilities and equipment for Telemetering, communication, control, and monitoring, including voice channels, between the Connection Point and the NLDC.

13.8.3 The Generators shall provide and install within the complex such equipment, including power line carrier equipment and/or fiber optic multiplexers, as needed for the complex to interconnect with the Transmission System equipment for tele-metering, communication, control, and monitoring, including voice channels, compatible with the Licensee's system or as agreed by the Licensee.

13.8.4 For the SCADA and EMS systems, the Single Buyer shall be responsible for providing and installing the equipment, including any Remote Terminal Units (RTUs)/ IEDs/PMUs/ Gateways within the Generator or Distribution Utility or Bulk Power Consumer sites. The Generator, Distribution Utility, and Bulk Power Consumer shall provide and install the complex interface terminals on the metering system and such other equipment needed to interface with the SCADA and EMS systems.

13.8.5 No Power Station and Transmission System substation shall be commissioned without communication and SCADA integration.

13.9 AGREED PROCEDURE FOR COMMUNICATION AND DATA TRANSMISSION

Mutually agreed procedures shall be drawn up between the Licensee, the System Operator, and other Users, outlining inter-responsibility, accountability, and recording of day-to-day communication and data transmission on operational matters.

13.9.1. Data Requirement

The Licensee, the System Operator, and the Users shall furnish metering data to each other as applicable and as detailed in the Data Registration Section.

14. TESTING

14.1 INTRODUCTION

This **section** specifies the responsibilities and procedures for arranging and carrying out tests that have (or may have) an effect on the Transmission System or the Generation or Distribution System.

14.2 OBJECTIVE

The objective of the section is to establish whether Generating Units can operate within their Generation Schedule and Dispatch parameters as registered under the Data Registration Section and that the Generator and Distributor/ Bulk Power Consumer comply with Section 5 “Connection Conditions”. It shall also establish whether each Generating Unit’s Declared Available Capacity is as declared and that the requirements of the provisions of frequency, voltage management, and reserve capability are met in accordance with the provisions of the Grid Code.

14.3 RESPONSIBILITIES

The System Operator is responsible for ensuring that the following procedures are carried out. All Users are required to fully cooperate to ensure that all arrangements are made for the smooth execution of tests.

14.4 PROCEDURE

The System Operator shall monitor the performance of Generating Units against the registered parameters and the compliance by the Generator or Distributor with Section 5 "Connection Conditions" of the Grid Code.

The System Operator shall inform a Generator, and confirm in writing if monitoring demonstrates an apparent persistent or material mismatch in meeting the Generating Unit registered parameters or a breach of the Connection Conditions.

For all parameters except availability, the relevant Generator shall, as soon as possible, provide the System Operator with an explanation of the reasons for the failure to meet the requirements and the details of the action it proposes to take to meet the requirements and comply with the Grid Code.

The System Operator and the Generator will then discuss the action and endeavor to reach agreement on the actions required.

In the event that agreement cannot be reached within 10 days of the notification, the System Operator shall be entitled to propose that a test be carried out.

For the allocation of the costs of testing, the general principle shall be that the Test Proposer (the System Operator/ the Single Buyer) shall bear the costs if the results show that the test was not justified, and the Generator or Distribution Utility or Bulk Power Consumer shall bear the costs if the results show the test was justified.

14.5 TEST PROCEDURES FOR CONVENTIONAL GENERATION

14.5.1 Declared Available Capacity Testing

If the System Operator has reasonable suspicion that the Declared Available Capacity of a Generating Unit is not as declared, the System Operator may test that availability by issuing a dispatch instruction to the Generating Unit to attain the Declared Available Capacity. This may be instructed at any time, even though it has not been previously scheduled or dispatched on Merit Order or system grounds.

The issue of a Dispatch instruction shall initiate the test.

The Generating Unit will pass the test if it can attain and maintain its load at the Declared Available Capacity for 2 hours.

14.5.2 Schedule and Dispatch Instruction Testing

If the System Operator has reasonable suspicion that the scheduling and dispatch parameters of a Generating Unit are not as registered and has not received notification of a temporary change to the parameters, he may instruct the Generating Unit to demonstrate its capability of meeting its parameters. The Generator shall be given at least 48 hours notice of the test, and the duration shall be consistent with the time taken to measure the result.

The issue of a Dispatch instruction shall initiate the test.

The performance of the Generating Unit shall be recorded in the presence of a representative of the System Operator, the Generator and the Single Buyer.

The Generating Unit will pass the test if the parameters under test are within +/- 2.5% of the declared value.

14.5.3 Reactive Power Testing

If the System Operator has reasonable suspicion that the Reactive Power capability of a Generating Unit is not as registered and has not received notification of a temporary change, he may instruct the Generating Unit to demonstrate the capability of meeting its registered capability. The Generator shall be given at least 48 hours notice of the test, and the duration will be up to 60 minutes. The Transmission System voltage at the entry point shall be maintained by the Generator at the voltage specified by the test proposer by adjustment of Reactive Power on the remaining units (if available) or by the Licensee by appropriate tap changing at the substation, as necessary.

The issue of a Dispatch instruction shall initiate the test.

The performance of the Generating Unit shall be recorded in the presence of a representative of the System Operator, the Generator and the Single Buyer.

The Generating Unit will pass the test if it is within +/- 2.5% of the registered capability. Due account shall be taken of any conditions on the system that may affect the test.

14.5.4 Automatic Frequency Sensitive Testing

If the System Operator has reasonable suspicion that the capability of the automatic frequency sensitive performance (Primary & Secondary response) of a Generating Unit is not as registered and have not had notification of a temporary change he may instruct the Generating Unit to demonstrate the capability of meeting its registered capability. The Generator shall be given at least 48 hours notice of the test.

The performance of the Generating Unit and system frequency shall be recorded in the presence of a representative of the System Operator, the Generator and the Single Buyer. Where measurements of the Governor pilot oil/valve position are to be made such measurements should indicate that the Governor parameters are within limits. The Generating Unit will pass the test if it is within +/- 2.5% of the level of response registered.

14.5.5 Fast Start CapabilityTesting

If the System Operator has reasonable suspicion that the capability of the fast start performance of a Generating Unit is not as registered and has not received notification of a temporary change, he may instruct the Generating Unit to demonstrate the capability of meeting its registered capability. The Generator shall be given at least 48 hours notice of the test.

The issue of a Dispatch instruction shall initiate the test.

The performance of the Generating Unit and system frequency shall be recorded in the presence of a representative of the System Operator, the Generator and the Single Buyer. Where measurements of the Governor pilot oil or valve position are to be made, such measurements should indicate that the Governor parameters are within limits.

The Generating Unit will pass the test if, when synchronizing and running up to full declared availability, it meets its fast start capability.

14.5.6 Black Start Testing

The System Operator may, at any time, require aGenerator with Black Start capability to carry out a "Black Start Test" on a Generating Unit in order to demonstrate that the Black Start Power Station has Black Start capability.

Where the System Operator requires the Generator to carry out the "Black Start Test" the NLDC shall not require the test to be carried out on more than one Generating Unit.

The System Operator shall not require a Generator with a Black Start capability to carry out a "Black Start Test" more than once every calendar year in respect of any particular Generating Unit.

When the System Operator requires a "Black Start Test" it shall notify the relevant Generator at least 7 days prior to the start of the test with details of the proposed test.

All "Black Start Tests" shall be carried out at a time specified by the Licensee in the notice given and shall be undertaken in the presence of a representative of the System Operator, the Generator and the Single Buyer.

The Generating Unit will pass the test if it meets its Black Start capability.

14.5.7 Synchronization Time and Ramp Rate

If the System Operator has reasonable suspicion that the time required for the synchronization process and Ramp Rate of a Generating Unit are not as registered and has not had notification of a temporary change, he may instruct the Generating Unit to demonstrate its capability of meeting its registered capability. The Generator shall be given at least 48 hours notice of the test and the duration will be up to 60 minutes.

The issue of a Dispatch instruction shall initiate the test.

The performance of the Generating Unit shall be recorded in the presence of a representative of the System Operator, the Single Buyer and the Generator.

The Generating Unit will pass the test if, in the case of synchronization, the process is achieved within +/- 5 minutes of the registered synchronization time and, in the case of meeting Ramp Rates (up or down), the actual Ramp Rate is within +/- 10 % of the registered Ramp Rate.

14.6 TEST PROCEDURES FOR VRE GENERATION

14.6.1. If the System Operator has reasonable suspicion that any VRE Generating Plant or VRE Generating Unit is not in accordance with the requirements indicated in Section 5 (Connection Conditions) it may instruct the VRE Generating Plant or VRE Generation Unit to demonstrate the capability of meeting such requirements. The Generator shall be given at least 48 hours notice of the required test, and the duration will be for a period of up to 60 minutes.

The issue of a Dispatch instruction shall initiate the test.

The performance of the VRE Generating Plant or VRE Generating Unit shall be recorded in the presence of a representative of the System Operator and the Generator.

14.6.2. Following tests can be performed for VRE Generating Plants:

(a) The Reactive Power test shall demonstrate that the VRE Generation Plant meets the registered Reactive Power capability requirements specified in sub-section5.9.2. The VRE Generating Plant shall pass the test if the measured values are within ±5 percent of the indicated requirements.

(b) The Active Power control test shall demonstrate that the VRE Generation Plant has the capability to control the injected power, as specified in sub-Section 5.9.3.The VRE Generation Plant shall pass the test if the measured response is within ±5 percent of the required level of response within the timeframes indicated in such ub-section.

(c) The Voltage Control test shall demonstrate that the VRE Generation Plant has the capability to control the voltage at the Connection Point, as specified in sub-s ection 5.9.2. The VRE Generating Plant shall pass the test if:

i. In voltage control mode, the VRE Generating Plant is capable of controling the voltage at the Connection Point within a margin not greater than 0.01 p.u., provided the Reactive Power injected or absorbed is within the limits specified.

ii. Following a step change in voltage, the VRE Generation Plant shall be capable of achieving 90% of the change in Reactive Power output within a time of less than 5 seconds, reaching its final value within a time of no greater than 30 seconds.

iii. In power factor control mode, the VRE Generation Plant is capable of controlling the power factor at the Connection Point within the required Reactive Power range, with a target power factor in steps no greater than 0.01.

(d) The Low Voltage Ride Through and performance under disturbance capability tests shall demonstrate that the VRE Generation Plant is capable of withstand voltage drops as indicated in sub-Section 5.9.5. The VRE Generation Plant shall pass the test if its performance is equal to or better than the prescriptions in the said sub-section. The System Operator and the VRE Generator shall agree on the way that this test should be carried out.

14.7 FAILURE OF GENERATOR TO PASS TEST AND DISPUTES

If a Generating Unit fails to pass a test, the Generator shall provide the System Operator and the Single Buyer with a written report detailing the reasons for the failure, as far as they are known, within 3 days of the test. If a dispute arises relating to the failure, the System Operator may, with the agreement of the Generator, carry out a test on 48 hour notice.

If the Generating Unit fails to pass the test or re-test and a dispute occurs, then either party may refer the dispute to the Commission. The decision of the Commission shall be binding on both parties.

If the System Operator and the Generator agree that the Generating Unit has failed the test or re-tested, the Generator shall submit in writing to the System Operator and the Single Buyer for approval the date and time by which the Generator shall restore the faulty unit to a condition where it would pass the test.

If the Generating Unit fails to pass the test or re-test, the Generator may amend the relevant registered parameters of that Generating Unit to reflect the capability achieved under test until the Generating Unit can achieve the previously registered values in a further re-test.

Once the Generator has indicated to the System Operator the time and date that the Generating Unit can achieve the previously registered parameters, the System Operator may either accept them or require a further test on 48-hour notice to demonstrate that they can be achieved. If a dispute occurs, then either party may refer the dispute to the Commission. The decision of the Commission shall be binding on both parties.

15. NUMBERING AND NOMENCLATURE

15.1 INTRODUCTION

This section sets out the requirement that:

a. Licensee's HV Apparatus on User's sites and

b. User's HV Apparatus on Licensee's Sites

shall have numbering and nomenclature in accordance with the system used from time to time by the Licensee.

The numbering and nomenclature of each item of HV Apparatus shall be included in the Operation Diagram prepared for each site.

15.2 OBJECTIVE

The objective of this Section is to ensure, in so far as possible, the safe and effective operation of the Power System and to reduce the risk of human error faults by requiring that the numbering and nomenclature of User's Apparatus shall be in accordance with the Licensee's system at Connection Point sites.

15.3 SCOPE

The section applies to the Licensee and all Users.

15.4 PROCEDURE

Licensee's HV Apparatus on User's Sites

(*a*) Licensee's HV Apparatus on a User's sites shall have numbering and nomanclature in accordance with the system used by the Licensee.

(*b*) When the Licensee is to install HV Apparatus on a User's site, the Licensee shall notify the relevant User of the numbering and nomanclature to be adopted for that HV Apparatus at least eight months before installation.

(*c*) The notification shall be made in writing to the relevant User and will consist of a proposed Operation Diagram incorporating the proposed new HV Apparatus to be installed, its proposed numbering, and the date of installation.

(*d*) The relevant User shall respond in writing within one month of the notification, confirming receipt and confirming either that any other HV Apparatus of the User on the site does not have the numbeing and/or nomenclature that could be confused with that proposed by the Licensee, or, to the extent that it does, and that the relevant numbering and/or nomanclature will be changed before installation of the Licensee's HV Apparatus.

(e) The relevant User shall not install, or permit the installation of, any HV Apparatus on the site that has numbering and/or nomenclature that could be confused with the Licensee's HV Apparatus which is either already on that site or which the Licensee has notified the User will be installed on that site.

User's HV Apparatus on Licensee's Sites

(a) User's HV Apparatus on Licensee's sites shall have numbering and nomenclature in accordance with the system used by the Licensee.

(b) When a User is to install its HV Apparatus on the Licensee's site or wishes to replace existing HV Apparatus on the Licensee's site and also wishes to adopt new numbering and nomenclature for such HV Apparatus, the User shall notify the Licensee of the details of the HV Apparatus and the proposed numbering and nomenclature to be adopted for that HV Apparatus at least eight months before installation or change.

(c) The notification shall be made in writing to the Licensee and will consist of a proposed Operation Diagram incorporating the proposed new HV Apparatus to be installed, its proposed numbering, and the date of installation.

(d) The Licensee shall respond in writing within one month of the notification, confirming receipt and confirming whether or not the Licensee accepts the User's proposed numbering and nomenclature, and, if they are not acceptable, shall give details of the numbering and/or nomenclature that will be adopted for the User's HV Apparatus.

Changes

Where the Licensee, in its reasonable opinion, has decided that it needs to change the existing numbering or nomenclature of the Licensee's HV Apparatus on a User's site or the User's HV Apparatus on the Licensee's site:

(a) The provisions of the above paragraphs shall apply to such a change in the numbering of Licensee's HV Apparatus with any necessary amendments to those provisions to reflect that only a change is being made, and

(b) In the case of a change in the numbering or nomenclature of User's HV Apparatus on the Licensee's site, the Licensee shall notify the User of the numbering or nomenclature the User shall adopt for that HV Apparatus at least eight months prior to the change being needed, and the User shall respond in writing to the Licensee within one month of the notification confirming receipt.

In either case, the notification shall indicate the reason for the proposed change.

Users shall be provided upon request with details of the Licensee's current numbering and nomenclature system.

When either the Licensee or the User installs HV Apparatus which is subject to this Section, the Licensee or the User, as the case may be, installing such Apparatus shall be responsible for the provision and erection of clear and unambiguous labeling showing the numbering and nomenclature. Where a User is required to change the numbering and nomenclature, he shall be responsible for the provision and erection of clear and unambiguous labeling showing the numbering and nomenclature by the required date.

Where the Licensee changes the numbering and nomenclature of its HV Apparatus, under this Section, the Licensee shall be responsible for the provision and erection of clear and unambiguous labeling showing the numbering and nomenclature by the required date.

The Licensee shall not change the system of numbering and nomenclature unless to reflect new or newly adopted technology or for reasons of safety.

The Licensee shall submit the numbering and nomenclature to the Commission whenever adopted and whenever changed or revised.

16. DATA REGISTRATION

16.1 INTRODUCTION

This Section contains a list of all data required by the Licensee that is to be provided by Users and data required by Users to be provided by the Licensee at times specified in the Grid Code. Other Sections of the Grid Code contain the obligation to submit the data and defines the times when data is to be supplied by Users.

16.2 OBJECTIVE

The objective of the Section is to list all the data required to be provided by Users to the Licensee and vice versa, in accordance with the provisions of the Grid Code.

16.3 RESPONSIBILITIES

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

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

The Licensee shall inform all Users of the name, address and telephone number of the person responsible for receiving data.

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

Responsibility for the correctness of the data rests with the concerned Users providing the data.

16.4 DATA CATEGORIES AND STAGES IN REGISTRATION

Data as required to be exchanged have been listed in the Appendices of this Section under various categories with cross-reference to the concerned Sections. The Licensee and the System Operator may prepare structured formats for the Users to provide required data (based on data listed in the Appendices) for efficient management of related software.

16.5 CHANGES TO USERS DATA

Whenever any User becomes aware of a change to any items of data that are registered with the Licensee, the User must promptly notify the Licensee of the changes. The Licensee upon receipt of intimation of the changes, shall promptly correct the database accordingly. This shall also apply to any data compiled by the Licensee regarding its own system.

16.6 DATA NOT SUPPLIED

Users are obliged to supply data as referred to in the individual Section of the Grid Code and listed in the Data Registration Section Appendices. In case any data is unavailable and hence not supplied by any User, the Licensee may, acting reasonably, if and when necessary, estimate such data depending upon the urgency of the situation. Similarly, in case any data is unavailable and not supplied by the Licensee, 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 plants or Apparatus or upon such other information as the User or Licensee, as the case may be, deems appropriate.

16.7 SPECIAL CONSIDERATIONS

The Licensee and any other User may at any time make reasonable requests for extra data as necessary.

APPENDICES

APPENDIX	SUBJECT
A	**STANDARD PLANNING DATA**
	A.1 STANDARD PLANNING DATA (GENERATION)
	A.2 STANDARD PLANNING DATA (TRANSMISSION)
	A.3 STANDARD PLANNING DATA DISTRIBUTION
B	**DETAILED PLANNING DATA**
	B.1 DETAILED PLANNING DATA (GENERATION)
	B.2 DETAILED SYSTEM DATA, TRANSMISSION
	B.3 DETAILED PLANNING DATA, DISTRIBUTION
C	**OPERATIONAL PLANNING DATA**
	C.1 OUTAGE PLANNING DATA
	C.2 GENERATION SCHEDULING DATA
	C.3 DATA
	C.4 RESPONSE TO FREQUENCY CHANGE
	C.5 ESSENTIAL AND NON-ESSENTIAL LOAD DATA
D	**PROTECTION DATA**
E	**METERING DATA**

APPENDIX- A

DATA REGISTRATION

A. STANDARD PLANNING DATA

REFERENCE TO:

SECTION 4: SYSTEM PLANNING

SECTION 5: CONNECTION CONDITION

A.1 STANDARD PLANNING DATA(GENERATION)

A.1.1 THERMAL (FOSSILFUEL)

A.1.1.1 GENERAL

i.	Site	Give a location map to scale showing roads, railway lines, transmission lines, rivers, and reservoirs, if any.
ii.	Fossil Fuel Natural Gas, Diesel, Furnace Oil, Coal etc.,	Give information on means of coal transport from coal mines in the case of pithead stations or means of coal carriage and handling if coal is imported. [In the case of other fuels, give details of the source of the fuel and its transport.]
iii.	Water Sources	Give information on the availability of water for the operation of the Power Station.
iv.	Environmental	State whether forest or landsmining clearance areas are affected.
v.	Site map (To Scale)	Showing the area required for the Power Station, coal linkage, coal yard, water pipe line, ash disposal area, colony, etc.
vi.	Approximate period of construction.	

A.1.1.2	**CONNECTION**			
	i.	Connection Point	Give a single-line diagram of the proposed connection with the system.	
	ii.	Step up voltage for Connection	kV.	
A.1.1.3	**STATION CAPACITY**			
	i.	Total Power Station capacity (MW)	State whether development will be carried out in phases, and if so, furnish details.	
	ii.	No. of units & unit size	MW.	
A.1.1.4	**GENERATING UNIT DATA**			
	i.	Steam Generating Unit	State type, capacity, steam pressure, steam temperature, etc.	
	ii.	Steam turbine	State type and capacity.	
	iii.	Generator	*(a)*	Type.
			(b)	Rating (MVA).
			(c)	Terminal voltage (kV).
			(d)	Rated Power Factor.
			(e)	Reactive Power Capability (MVAR) in the rangeof 0.95 leading and 0.85 lagging.
			(f)	Short Circuit Ratio.
			(g)	Direct axis Synchronous reactance (% on MVA rating).
			(h)	Direct axis Transient reactance (% on MVA rating).
			(i)	Direct axis sub-transient reactance (% on MVA rating).
			(j)	Auxiliary Power Requirement (MW).

iv.	Generator Transformer	*(a)*	Type.
		(b)	Rated capacity (MVA).
		(c)	Voltage Ratio (HV/LV).
		(d)	Tap change Range (+% to -%) Percentage Impedance (Positive Sequence at Full load).

A.1.2 HYDRO ELECTRICAL

A.1.2.1 GENERAL

i.	Site	Give a location map to scale showing roads, railway lines, and transmission lines.
ii.	Site map (To scale)	Showing the proposed dam, reservoir area, water conductor system, forebay, power house, etc.
iii.	Submerged Area	Give information on areas submerged, villages submerged, submerged forest land, agricultural land, etc.
iv.	Approximate period of construction.	

A.1.2.2 CONNECTION

	Connection Point	Give a single-line diagram of the proposed connection with the Transmission System.
i.	Step up voltage for Connection	kV.

A.1.2.3 STATION CAPACITY

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

A.1.2.4 GENERATING UNIT DATA

i.	Operating Head (in Mtr.)	*a)*	Maximum.
		b)	Minimum.
		c)	Average.
ii.	Turbine		State Type and capacity
iii.	**Generator**	*a)*	Type.
		b)	Rating (MVA).
		c)	Terminal voltage (kV).
		d)	Rated Power Factor.
		e)	Reactive Power Capability (MVAR) in the range of 0.95 for leading and 0.85 for lagging.
		f)	Short Circuit Ratio.
		g)	Direct axis Synchronous reactance (% on MVA rating).
		h)	Direct axis Transient reactance (% on rated MVA).
		i)	Direct axis sub-transient reactance (% on rated MVA).
		j)	Auxiliary Power Requirement (MW).
iv.	Generator Transformer	*a)*	Type.
		b)	Rated Capacity (MVA).
		c)	Voltage Ratio.
		d)	HV/LV.
		e)	Tap change Range (+% to -%).
		f)	Percentage Impedance (Positive sequence at full load).

A.1.3 WIND FARMS

A.1.3.1 GENERAL

i.	Site	Give a location map to scale showing roads, railway lines, and transmission lines.
ii.	Site map (To scale)	Showing the proposed Wind Farm area, location of each Wind Turbine, power house, etc.
iii.	Approximate period of construction.	

A.1.3.2 CONNECTION

i.	Connection Point	Give a single-line diagram of the proposed connection with the Transmission System.
ii.	Step up voltage for Connection	kV.

A.1.3.3 STATION CAPACITY

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

A.1.3.4 GENERATING UNIT DATA

i.	Wind Generating Plant	State the number of Wind Turbines, type, and capacity.	
ii.	Wind Turbines	*a)*	Type (fixed speed/ variable speed); (induction machine, double-fed induction machine, synchronous Generator); (directly coupled or coupled through inverters).

b) Wind Turbine manufacturer.

c) Rating (MVA).

d) Terminal voltage (kV).

e) Rated Power Factor.

f) Reactive Power Capability (MVAR) curve.

g) Frequency tolerance range.

h) Rated wind speed (m/s).

i) Cut-in wind speed (m/s).

j) Cut-off wind speed (m/s).

k) Short Circuit Ratio (% on MVA rating).

l) Auxiliary Power Requirement (MW).

iii. Generator Transformer

a) Type.

b) Rated Capacity (MVA).

c) Voltage Ratio HV/LV.

d) Tap change Range (+% to -%).

e) Percentage Impedance (Positive sequence at full load).

A.1.4 PV GENERATING PLANTS

A.1.4.1 GENERAL

i. Site — Give a location map to scale showing roads, railway lines, and transmission lines.

ii. Site map (To scale) — Showing the proposed PV Generation Plant area, location of PV panels, and general arrangement.

iii. Approximate period of construction.

A.1.4.2 CONNECTION

i.	Connection Point	Give a single-line diagram proposed connection with the Transmission System.
ii.	Step up voltage for Connection	kV.

A.1.4.3 STATION CAPACITY

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

A.1.4.4 GENERATING UNIT DATA

i.	**PV Generating Plant**	State number of solar panels, type and capacity.	
ii.	PV solar panels	*a)*	Type and technology.
		b)	PV panels and inverter manufacturers.
		c)	Solar Panels Rating (MWdc).
		d)	Inverters rating (MWac).
		e)	Terminal voltage (kV).
		f)	Rated Power Factor.
		g)	Reactive Power Capability (MVAR) curve.
		h)	Frequency tolerance range.
		i)	Auxiliary Power Requirement (MW).
iii.	Generator Transformer	*a)*	Type.
		b)	Rated Capacity (MVA).
		c)	Voltage Ratio HV/LV.
		d)	Tap change Range (+% to -%).
		e)	Percentage Impedance (Positive sequence at full load).

A.2 STANDARD PLANNING DATA (TRANSMISSION)

Note: The compilation of the data is an internal matter of the Licensee, and as such, the Licensee shall make arrangements for getting the required data from different Departments of the Licensee to update its Standard Planning Data in the format given below:

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

ii. Voltage of line (kV).

iii. No. of circuits.

iv. Route length (km).

v. Conductor type and sizes.

vi. Line parameters (p.u. values).

a. Resistance/km.

b. Inductance/km.

c. Susceptance/km (B/2).

vii. Approximate power flow expected in MW and MVAR.

viii. Terrain of route - Give information regarding the nature of the terrain, i.e., forest land, fallow land, agricultural and river basins, hill slopes, etc.

ix. Route map (to Scale) - Furnish topographical map showing the proposed route, showing existing power lines and telecommunication lines.

x. Purpose of Connection - Reference to scheme.

xi. Approximate period of Construction.

A.3 STANDARD PLANNING DATA DISTRIBUTION

A.3.1 GENERAL

i. Area map (to Scale)- Marking the area in the map for which Distribution License is applied for.

ii. Consumer Data- Furnish categories of consumers, their numbers, and connected loads.

iii. Reference to the Electrical Divisions presently in charge of the Distribution.

A.3.2 CONNECTION

i. Connection Points - Furnish a single-line diagram showing Connection Points.

ii. Voltage of supply at Connection Points.

iii. Names of Grid substations feeding the Connection Points.

A.3.3 LINES AND SUBSTATIONS

i. Line data- Furnish lengths of line and voltages within the area.

ii. Substation data- Furnish details of 33/11 kV substations, 11/0.4 kV substations, and capacitor installations.

A.3.4 LOADS

i. Loads drawn at the Connection Points.

ii. Details of loads fed at EHV, if any Give the name of the consumer, the voltage of supply, the contract demand, the name of Grid substation from which the line is drawn, and the length of the EHV line from Grid substation to the consumer's premises.

A.3.5 DEMAND DATA (FOR ALL LOADS 5 MW AND ABOVE)

i. Type of load - State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads, etc.

ii. Rated voltage and phase.

iii. Electrical loading of equipment- State the number and size of motors, types of drives, and control arrangements.

iv. Sensitivity of load to voltage and frequency of supply.

v. Maximum Harmonic content of the load.

vi. Average and maximum Phase unbalance of load.

vii. Nearest substation from which loads are to be fed.

viii. Location map (to scale)- Showing the location of the load with reference to lines and substations in the vicinity.

A.3.6 LOAD FORECAST DATA

i. Peak load and energy forecasts for each category of load for each of the succeeding 20 years.

ii. Details of the methodology and assumptions on which forecasts are based.

iii. If supply is received from more than one Substation, the substation-wise break down of peak load and energy projections for each category of loads for each of the succeeding 20 years along with the estimated daily load curve.

iv. Details of loads 5 MW and above.

a. Name of the prospective consumer.

b. Location and nature of the load or complex.

c. Substation from which to be fed.

d. Voltage of supply.

e. Phasing of load.

APPENDIX- B

B. DETAILED PLANNING DATA

REFERENCE TO:

SECTION 4: SYSTEM PLANNING

SECTION 5: CONNECTION CONDITIONS

B.1 DETAILED PLANNING DATA (GENERATION)

PART1. FOR ROUTINE SUBMISSION

B.1.1 THERMAL POWER STATIONS (FOSSIL FUEL)

B.1.1.1 GENERAL

i. Name of Power Station.

ii. Number and capacity of Generating Units (MVA).

iii. Ratings of all major equipment (boilers and major accessories, turbines, alternators, Generating Unit transformers etc.).

iv. Single-line diagram of Power Station and switchyard.

v. Relaying and metering diagram.

vi. Neutral Grounding of Generating Units.

vii. Excitation control (What type is used? e.g. Thyristor, Fast Brushless?).

viii. Earthing arrangements with earth resistance values.

B.1.1.2 PROTECTION AND METERING

i. Full description, including settings for all relays and protection systems installed on the **Generating Unit**, **Generating Unit** transformer, auxiliary transformer, and electrical motor of major equipment listed, but not limited to, above.

ii. Full description, including settings for all relays installed on all outgoing feeders from **Power Station** switchyard, tie circuit breakers, and incoming circuit breakers.

iii. Full description of the inter-tripping of circuit breakers at the **Connection Point** with the **Transmission System**.

iv. Most probable fault clearance time for electrical faults on the **User's** system.

v. Full description of operational and commercial metering schemes.

B.1.1.3 SWITCHYARD

In relation to interconnecting transformers:

i. Rated MVA.

ii. Voltage Ratio.

iii. Vector Group.

iv. Positive sequence reactance for maximum, minimum, and normal tap. (% on MVA).

v. Positive sequence resistance for maximum, minimum, normal Tap. (% on MVA).

vi. Zero sequence reactance. (% on MVA).

vii. Tap changer Range (+% to -%) and steps.

viii. Type of Tap changer. (OFF/ON).

In relation to switchgear including circuit breakers, isolators on all circuits connected to the **Connection Points**:

i. Rated voltage (kV).

ii. Type of circuit breaker(MOCB, ABCB, or SF6).

iii. Rated short circuit breaking current (kA) 3- phases.

iv. Rated short circuit breaking current (kA) 1- phases.

v. Rated short circuit, making current (kA) 3- phases.

vi. Rated short circuit making current (kA) 1-phase.

vii. Provisions for auto-reclosing with details.

Lightning Arresters:

Technical data.

Communication:

Details of equipment installed at **Connection Points**.

Basic Insulation Level (kV):

i. Busbar.

ii. Switchgear.

iii. Transformer bushings.

iv. Transformer windings.

B.1.1.4 GENERATING UNITS

(a) Parameters of **Generating Units**:

i. Rated terminal voltage (kV).

ii. Rated MVA.

iii. Rated MW.

iv. Inertia constant (MW Sec./MVA)H.

v. Short circuit ratio.

vi. Direct axis Synchronous reactance (% on MVA)X_d.

vii. Direct axis Transient reactance (% on MVA)X'_d.

viii. Direct axis sub-transient reactance (% on MVA)X''_d (Saturated/ Unsaturated).

ix. Quadrature axis Synchronous reactance (% on MVA)X_q.

x. Quadrature axis Transient reactance (% on MVA)X'_q.

xi. Quadrature axis sub-transient reactance (% on MVA)X''_q(Saturated/ Unsaturated).

xii. Direct axis Transient open circuit time constant (Sec)T'_{do}.

xiii. Direct axis sub-transient open circuit time constant (Sec)T''_{do}.

xiv. Quadrature axis Transient open circuit time constant (Sec)T''_{qo}.

xv. Quadrature axis sub-transient open circuit time constant (Sec)T'_{qo}.

xvi. Stator resistance (Ohm)R_a.

xvii. Stator leakage reactance (Ohm)X_l.

xviii. Stator time constant (Sec).

xix. Rated field current (A).

xx. Open circuit saturation characteristic for various terminal giving the compounding current to achieve the same.

xxi. Negative sequence reactance, X_2 (Saturated/ Unsaturated).

xxii. Zero-sequence reactance, X_0(Saturated/ Unsaturated).

(b) Parameters of Excitation Control System:

i. Type of excitation.

ii. Maximum field voltage.

iii. Minimum field voltage.

iv. Rated field voltage.

v. Details of the excitation loop are shown in block diagrams showing the transfer functions of individual elements using IEEE symbols.

vi. Dynamic characteristics of an over-excitation limiter.

vii. Dynamic characteristics of an under-excitation limiter.

(c) Parameters of Governor:

i. Governor average gain (MW/Hz).

ii. Speeder motor setting range.

iii. Time constant of the steam or fuel governor valve.

iv. Governor valve opening limits.

v. Governor valve rate limits.

vi. Time constant of the turbine.

vii. Governor block diagram showing transfer functions of individual elements using IEEE symbols.

(d) Operational Parameters:

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

ii. Minimum time between synchronizing different **Generating Units** in a **Power Station**.

iii. The minimum block load requirements for synchronizing.

iv. Time required for synchronizing a **Generating Unit** for the following conditions:

a) Hot

b) Warm

c) Cold

v. Maximum **Generating Unit** loading rates for the following conditions:

a) Hot

b) Warm

c) Cold

vi. Minimum load without oil support (MW).

B.1.2 HYDRO-ELECTRIC STATIONS

B.1.2.1 GENERAL

i. Name of **Power Station**.

ii. No. and capacity of units.(MVA)

iii. Ratings of all major equipment.

a) Turbines (HP).

b) **Generators** (MVA).

c) Generator Transformers (MVA).

d) Auxiliary Transformers (MVA).

iv. Single-line diagram of **Power Station** and switchyard.

v. Relaying and metering diagram.

vi. Neutral grounding of **Generator**.

vii. Excitation control.

viii. Earthing arrangements with earth resistance values.

ix. Reservoir Data.

a) Salient features

b) Type of Reservoir

1. Multipurpose.
2. For Power.

c) Operating Table with

1. Area capacity curves and
2. Unit capability at different net heads.

d) Rule Curve.

B.1.2.2 PROTECTION

i. Full description, including settings for all relays and protection systems installed on the Generating Unit,generator transformer, auxiliary transformer and electrical motor of major equipment, includeding but not limited to those listed above.

ii. Full description, including settings for all relays installed on all outgoing feeders from Power Station switchyard, tie breakers, and incoming breakers.

iii. Full description of inter-tripping of breakers at the point or Connection Points with the Transmission System.

iv. Most probable fault clearance time for electrical faults on the User's System.

B.1.2.3 SWITCHYARD

(a) Interconnecting Transformers:

i. Rated MVA.

ii. Voltage ratio.

iii. Vector group.

iv. Positive sequence reactance for maximum, minimum, and normal tap. (% on MVA).

v. Positive sequence resistance for maximum, minimum, and normal Tap (% on MVA).

vi. Zero sequence reactance (% on MVA).

vii. Tap changer range (+% to -%) and steps.

viii. Type of tap changer (OFF/ON).

(b) Switchgear (including circuit breakers and isolators on all circuits connected to the **Connection Points**.)

i. Rated voltage (kV).

ii. Type of Breaker (MOCB/ABCB/SF6).

iii. Rated short circuit breaking current (kA) 3sphases.

iv. Rated short circuit breaking current (kA) 1 phase.

v. Rated short circuit making current (kA) 3 phases.

vi. Rated short circuit making current (kA) 1 phase.

vii. Provisions for auto-reclosing with details.

(c) Lightning Arresters: Technical Data.

(d) Communications:

Details of communications equipment installed at **Connection Points**.

(e) Basic Insulation Level (kV):

i. Busbar.

ii. Switchgear.

iii. Transformer Bushings.

iv. Transformer windings.

B.1.2.4 GENERATING UNITS

(a) Parameters of the Generator

i. Rated terminal voltage (kV).

ii. Rated MVA.

iii. Rated MW.

iv. Inertia constant (MW sec/MVA) H.

v. Short circuit ratio.

vi. Direct axis synchronous reactance. (% on MVA) X_d.

vii. Direct axis transient reactance (% on MVA) X'_d.

viii. Direct axis sub-transient reactance (% on MVA) X''_d (Saturated/ Unsaturated).

ix. Quadrature axis synchronous reactance (% on MVA) X_q.

x. Quadrature axis transient reactance (% on MVA) X'_q.

xi. Quadrature axis sub-transientre actance (% on MVA) X''_q (Saturated/ Unsaturated) .

xii. Direct axis transient open circuit time constant (sec) T'_{do}.

xiii. Direct axis sub-transient open circuit time constant (Sec) T''_{do}.

xiv. Quadrature axis transient open circuit time constant (Sec) T'_{qo}.

xv. Quadrature axis transient open circuit time constant (Sec) T''_{qo}.

xvi. Stator Resistance (Ohm) R_a.

xvii. Stator leakage reactance (Ohm) X_l.

xviii. Stator time constant(Sec).

xix. Rated Field current(A).

xx. Open-Circuit saturation characteristics of the **Generator** for various terminal voltages giving the compounding current to achieve this.

xxi. Type of Turbine

xxii. Operating Head (Mtr.).

xxiii. Discharge with Full Gate Opening (cusecs).

xxiv. Speed Rise on Total Load Throw Off (%).

xxv. Negative sequence reactance, X_2 (Saturated/ Unsaturated).

xxvi. Zero-sequence reactance, X_0 (Saturated/ Unsaturated).

(b) Parameters of the Excitation Control System: As applicable to thermal Power Stations.

(c) Parameters of the Governor:

As applicable to thermal Power Station.

(d) Operational Parameter:

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

ii. Minimum time between synchronizing different Generating Units in a Power Station.

iii. Minimum block load requirements for synchronizing.

B.1.3 VRE GENERATING PLANTS

B.1.3.1 GENERAL

i. Name of Power Station.

ii. No. and capacity of wind turbines. (MVA)

iii. Ratings of all major equipment:

- *a)* Wind Turbines (MVA) or PV panels (MVA)
- *b)* Generator Transformers (MVA).
- *c)* Auxiliary Transformers (MVA).

iv. Single-line diagram of Power Station and switchyard.

v. Relaying and metering diagram.

vi. Neutral grounding of Generator.

vii. Voltage control.

viii. Earthing arrangements with earth resistance values.

ix. Wind Characteristics (for Wind Power plants):

- *a)* Expected monthly production (MWh)
- *b)* Average wind and direction (monthly)
- *c)* Wind Turbine Operating characteristics
    1. Cut-in wind;
    2. Cut-off wind; and
    3. Wind-electrical power curve

x. Characteristics of the PV system (for PV power plants):

- *a)* Expected monthly production (MWh)
- *b)* Hourly average irradiation (for each month)
- *c)* PV system characteristics:
    1. Threshold irradiation (W/m^2) for plant startup;
    2. Irradiation-electrical power curve; and
    3. Plant performance ratio.

B.1.3.2 PROTECTION

i. Full description, including settings for all relays and protection systems installed on the VRE Generating Plant, generator transformer, auxiliary transformer, and electrical motor of major equipment included, but not limited to those listed above.

ii. Full description, including settings for all relays installed on all outgoing feeders from Power Station switchyard, tie breakers, and incoming breakers.

iii. Full description of intertripping of breakers at the point or points of C\connection with the Transmission System.

iv. Most probable fault clearance time for electrical faults on the User's System.

B.1.3.3 SWITCHYARD

a) Interconnecting Transformers:

i. Rated MVA.

ii. Voltage ratio.

iii. Vector group.

iv. Positive sequence reactance for maximum, minimum, and normal tap (% on MVA).

v. Positive sequence resistance for maximum, minimum, and normal Tap (% on MVA).

vi. Zero sequence reactance (% on MVA).

vii. Tap changer range (+% to -%) and steps.

viii. Type of tap changer. (OFF/ON).

b) Switchgear (including circuit breakers, and isolators on all circuits connected to the Connection Points):

i. Rated voltage (kV).

ii. Type of Breaker (MOCB/ ABCB/ SF6).

iii. Rated short circuit breaking current (kA) 3 phase.

iv. Rated short circuit breaking current (kA) 1 phase.

v. Rated short circuit making current (kA) 3 phase.

vi. Rated short circuit making current (kA) 1 phase.

vii. Provisions for auto-reclosing with details.

c) Lightning Arresters:

Technical data.

d) Communications:

Details of communications equipment installed at Connection Points.

e) Basic Insulation Level (kV):

i. Busbar.

ii. Switchgear.

iii. Transformer Bushings.

iv. Transformer windings.

B.1.3.4 VRE GENERATING UNITS

a) Parameters of the Generator:

i. Rated terminal voltage (kV).

ii. Rated MVA.

iii. Rated MW.

iv. Inertia constant (MWsec/MVA) H. (for wind turbines directly connected)

v. Short circuit ratio.

vi. Frequency tolerance range.

vii. Voltage tolerance range.

viii. Overload capability and duration.

ix. THD level.

x. Maximum fault level.

xi. Auxiliary power requirement.

xii. Reactive power capability (MVAR).

b) Parameters of the Voltage Control System:

i. Type of control voltage.

ii. Details of the voltage control loop are shown in block diagrams showing the transfer functions of individual elements using IEEE symbols.

c) Parameters of the Active Power control:

i. Block diagram showing transfer functions of individual elements using IEEE symbols.

d) Operational Parameter:

i. Minimum notice required to synchronize a VRE Generating Plant from desynchronization.

ii. Minimum block load requirements for synchronizing.

iii. Minimum synchronization time.

e) Protection Features:

i. Type of anti-islanding protection scheme.

PART 2. FOR SUBMISSION ON REQUEST BY LICENSEE

B.1.4 THERMAL POWER STATIONS

B.1.4.1 GENERAL

i. Detailed Project Report.

ii. Status Report:

a. Land.

b. Fossil Fuel.

c. Water.

d. Environmental clearance.

e. Rehabilitation of displaced persons.

iii. Techno-economic approval by the Commission.

iv. Approval of the Bangladesh Government

v. Financial Tie-up.

B.1.4.2 CONNECTION

i. Reports of Studies for parallel operation with the Transmission System:

a. Short circuit studies.

b. Stability studies.

c. Load flow studies.

ii. Proposed Connection with the Transmission System:

a. Voltage.

b. Number of circuits.

c. Connection Point.

B.1.5 HYDRO-ELECTRIC POWER STATIONS

B.1.5.1 GENERAL

i. Detailed Project Report.

ii. Status Report:

a. Topographical survey.

b. Geological survey.

c. Land.

d. Environmental clearance.

e. Rehabilitation of displaced persons.

iii. Techno-economic approval by the Commission.

iv. Approval of the Bangladesh Government.

v. Financial Tie-up.

B.1.5.2 CONNECTION

i. Reports of Studies for Parallel Operation with the Transmission System:

a. Short circuit studies.

b. Stability studies.

c. Load flow studies.

ii. Proposed Connection with the Transmission System:

a. Voltage.

b. Number of circuits.

c. Connection Point.

B.1.6 VRE GENERATING STATIONS

B.1.6.1 GENERAL

i. Detailed Project Report.

ii. Status Report:

a. Topographical survey.

b. Geological survey.

c. Land.

d. Environmental clearance.

e. Rehabilitation of displaced persons.

iii. Techno-economic approval by the Commission.

iv. Approval of the Bangladesh Government.

v. Financial Tie-up.

B.1.6.2 CONNECTION

iii. Reports of Studies for parallel operation with the Transmission System:

a. Short circuit studies.

b. Stability studies.

c. Load flow studies.

iv. Proposed Connection with the Transmission System:

a. Voltage.

b. Number of circuits.

c. Connection Point.

B.2 DETAILED SYSTEM DATA, TRANSMISSION

B.2.1 GENERAL

i. Single-line diagram of the Transmission System down to the 33 kV bus at Grid substation details:

a. Name of the Substation.

b. Power Station, connected.

c. Number and length of circuits.

d. Interconnecting transformers.

e. Substation bus layouts.

f. Power transformers.

g. Reactive compensation equipment.

ii. Substation layout diagrams show:

a. Busbar layouts.

b. Electrical circuitry, lines, cables, transformers, switchgear, etc.

c. Phasing arrangements.

d. Earthing arrangements.

e. Switching facilities and interlocking arrangements.

f. Operating voltages.

g. Numbering and nomenclature:

1) Transformers.

2) Circuits.

3) Circuit breakers.

4) Isolating switches.

B.2.2 **LINE PARAMETERS** (For all circuits)

i. Designation of Line.

ii. Length of line (km).

iii. Number of circuits.

iv. Per Circuit values:

a. Operating voltage(kV).

b. Positive Phase Ssequence Reactance (p.u.on100MVA)X_l.

c. Positive Phase Sequence Resistance (p.u.on100MVA)R_l.

d. Positive Phase Sequence Susceptance (p.u. on 100 MVA)B_l.

e. Zero-Phase Sequence Reactance (p.u.on100MVA)X_o.

f. Zero-Phase Sequence Resistance (p.u.on100MVA)R_o.

g. Zero-Phase Sequence Susceptance (p.u. on 100 MVA)B_o.

B.2.3 **TRANSFORMER PARAMETERS** (For all transformers)

i. Rated MVA.

ii. Voltage Ratio.

iii. Vector Group.

iv. Positive sequence reactance, maximum, minimum, and normal (p.u. on 100 MVA)X_1

v. Positive sequence, resistance maximum, minimum, and normal (p.u. on 100 MVA)R_1

vi. Zero-sequence reactance (p.u. on 100MVA).

vii. Tap change range (+% to -%) and steps.

viii. Details of Tap changer (OFF/ON).

B.2.4 **EQUIPMENT DETAILS** (For all substations)

i. Circuit Breakers.

ii. Isolating switches.

iii. Current Transformers.

iv. Potential Transformers.

B.2.5 RELAYING AND METERING

i. Relay protection installed for all transformers and feeders along with their settings and level of coordination with other Users.

ii. Metering Details.

B.2.6 SYSTEM STUDIES

i. Load flow studies (peak and off-peak loads).

ii. Transient stability studies for three-phase faults in critical lines.

iii. Dynamic Stability Studies

iv. Short circuit studies (three-phase and single-phase to earth)

v. Transmission and distribution losses in the system**.**

B.2.7 DEMAND DATA (For all substations)

i. Demand Profile (Peak and off peak load).

B.2.8 REACTIVE COMPENSATION EQUIPMENT

i. Type of equipment (fixed or variable).

ii. Capacities and/or inductive rating or its operating range in MVAR.

iii. Details of control.

iv. Connection Point to the System.

B.3 DETAILED PLANNING DATA, DISTRIBUTION

B.3.1 GENERAL

i. Distribution map (to scale) showing all lines up to 33 kV and 33/11 kV substations belonging to the Distribution Utility.

ii. Single-line diagram of Distribution System **(**showing distribution lines Connection Points with the Transmission System, 132/33 kV and 33/11 kV substations).

iii. Numbering and nomenclature of lines and substations (Identified with feeding Grid substations of the Transmission System and concerned 132/33 kV and 33/11 kV substations of the Distribution Utility).

B.3.2 CONNECTION

i. Connection Points (Furnish details of the existing arrangement of connections).

ii. Full description of the operational and commercial metering schemes.

B.3.3 LOADS

i. Connected load - Furnish consumer details, numbers of consumers category- wise, and details of loads 1 MW and above.

ii. Information on diversity of load and coincidence factor.

iii. Daily demand profile (current and forecast) on each 132/33 kV and 33/11 kV substation.

iv. Cumulative demand profile of Distribution System (current and forecast).

APPENDIX- C

C. OPERATIONAL PLANNING DATA

C.1 OUTAGE PLANNING DATA

REFERENCE TO:

SECTION 6: OUTAGE PLANNING

C.1.1 DEMAND ESTIMATES

Item	To be Submitted By
i. Estimated aggregate annual sales of energy in million units and peak and off-peak demand in MW and MVAR at each Connection Point for the period from July of the current year to June of next year.	31^{st} March of current year.
ii. Estimated aggregate monthly sales of energy in million units and peak and off-peak demand in MW and MVAR at each Connection Point for the next month.	15^{th} of current month
iii. Hourly demand estimates for the day ahead.	10.00 Hours every day

C.1.2 ESTIMATES OF LOAD SHEDDING

Item	To be Submitted By
i. Details of discrete load blocks that may be shed to comply with instructions issued by the System Operator when required from each Connection Point.	Soon after connection is made.

C.1.3 YEAR AHEAD OUTAGE PROGRAMME

(For the period July to June)

C.1.3.1 GENERATORS OUTAGE PROGRAMME

Item	To be Submitted By
i. Identification of Generating Unit.	31st March of each year
ii. MW, which will not be available as a result of the Outage.	31st March of each year
iii. Preferred start date and start time or range of start dates and start times and period of Outage.	31st March of each year
iv. If outages are required to meet statutory requirements, then the latest date by which the Outage must be taken.	31st March of each year

C.1.3.2 YEAR AHEAD DISTRIBUTION UTILITY'S OUTAGE PROGRAMME

Item	To be Submitted By
i. Loads in MW are not available from any Connection Point.	31st March of each year
ii. Identification of Connection Point.	31st March of each year
iii. Period of suspension of drawal with start date and start time.	31st March of each year

C.1.3.3 THE LICENSEE'S OVERALL OUTAGE PROGRAMME

Item	To be Submitted By
i. Report on proposed Outage program	31st April of each year
ii. Release of finally agreed Outage plan.	31st May of each year

C.2 GENERATION SCHEDULING DATA

REFERENCE TO:

SECTION 7 : SCHEDULE AND DISPATCH

Item		To be Submitted By
i.	36 hours ahead of hourly MW and MVAR Declared Available (forecasted in the case of VRE) Capacity (00.00 - 24.00 Hours) of all Generator Units.	12.00 Hours every day.
ii.	Status of Generating Unit excitation AVR (or voltage control system) in service (Yes orNo).	12.00 Hours every day.
iii.	Status of Generating Unit speed control system. Governor (or Active Power control system) in service (Yes or No).	12.00 Hours every day.
iv.	Spinning reserve capability (MW)	12.00 Hours every day.
v.	Backing down capability with or without oil support (MW)	12.00 Hours every day.
vi.	Hydro reservoir levels and restrictions (rule curve)	12.00 Hours every day.
vii.	Generating Units hourly summation outputs (MW)	12.00 Hours every day
viii.	Provisional day after Declared Availability Capacity notification	

C.3 DATA

REFERENCE TO:

SECTION 8 : FREQUENCY AND VOLTAGE MANAGEMENT

Item	**To be Submitted By**
i. Generators shall submit to the Licensee up-to-date Capability Curves for all Generating Units.	On receipt of request by the **Licensee**

C.4 RESPONSE TO FREQUENCY CHANGE

REFERENCE TO:

SECTION 8: FREQUENCY AND VOLTAGE MANAGEMENT

i. Primary response in MW at different levels of loads ranging from minimum generation to registered capacity for frequency changes resulting in fully opening the governor valve.

ii. Secondary response in MW to frequency changes.

Item	**To be Submitted By**
i. Generators shall provide hourly generation summation to LDC.	To be submitted by real time basis
ii. Logged readings of Generators to LDC.	As required
iii. Detailed report of Generating Unit tripping on monthly basis.	In the first week of the succeeding month

C.5 ESSENTIAL AND NON-ESSENTIAL LOAD DATA

REFERENCE TO:

SECTION 9: CONTINGENCYPLANNING

Item	**To be Submitted By**
i. 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

D. PROTECTION DATA

REFERENCE TO:

SECTION 12: PROTECTION

Item	To be Submitted By
i. Generators shall submit details of protection requirements 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**
ii. The Licensee 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

E. METERING DATA

REFERENCE TO:

SECTION 13: METERING

Item	To be Submitted By
i. **Generators** shall submit details of metering equipment and schemes installed by them in accordance with PPA as referred to in B.1. Detailed Planning Data under sub-section "Protection and Metering".	As applicable to **Detailed Planning Data**
ii. The Licensee shall submit details of metering 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**
iii. The Distribution Utilities shall submit details of metering equipment and schemes installed by them in accordance with PSA as referred to in B.3. Detailed Planning Data, Distribution under sub-section "Relaying and Metering" in relation to Connection with any User.	As applicable to **Detailed Planning Data**

17. PERFORMANCE STANDARDS FOR TRANSMISSION

17.1 PURPOSE AND SCOPE

17.1.1 Purpose

(a) To ensure the quality of electric power on the Grid;

(b) To ensure that the Grid will be operated in a safe and efficient manner and with a high degree of reliability; and

(c) To specify safety standards for the protection of personnel in the work environment.

17.1.2 Scope of Application

This Chapter applies to all Grid Users, including:

(a) The Licensee;

(b) System Operator;

(c) Generators;

(d) Distribution Utilities; and

(e) Any other Entity (e.g., owners of HVDC converters, Bulk Power Consumers, large furnaces, etc.) with a User System connected to the Grid.

17.2 POWER QUALITY STANDARDS

17.2.1 Power Quality Problems

For the purpose of this **Section**, Power Quality shall be defined as the quality of the voltage, including its frequency and the resulting current, that are measured in the Grid during normal conditions.

A Power Quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the system:

(a) The System Frequency has deviated from the nominal value of 50Hz;

(b) Voltage magnitudes are outside their allowable range of variation;

(c) Harmonic frequencies are present in the System;

(d) There is an imbalance in the magnitude of the phase voltages;

(e) The phase displacement between the voltages is not equal to 120 degrees;

(f) Voltage fluctuations cause flicker that is outside the allowable Flicker Severity limits; or

(g) High-frequency Overvoltages are present in the Grid.

17.2.2 Frequency Variations

The nominal fundamental frequency shall be 50 Hz.

The control of System frequency shall be the responsibility of the System Operator.The System Operator shall maintain the fundamental frequency within the limits of 49.5 Hz and 50.5 Hz during normal conditions.

17.2.3 Voltage Variations

For the purpose of this Section, Voltage Variation shall be defined as the deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent.Voltage variations will either be of short-duration or long duration.

A short-duration Voltage Variation shall be defined as a variation of the RMS value of the voltage from the nominal voltage for a time greater than one-half cycle of the power frequency but not exceeding one minute. A short-duration Voltage Variation is a Voltage Swell if the RMS value of the voltage increases to between 110 percent and 180 percent of the nominal value. A short-duration Voltage Variation is a Voltage Sag (or Voltage Dip) if the RMS value of the voltage decreases to between 10 percent and 90 percent of the nominal value.

A long-duration Voltage Variation shall be defined as a variation of the RMS value of the voltage from the nominal voltage for a time greater than one minute. A Long Duration Voltage Variation is an Undervoltage if the RMS value of the voltage is less than or equal to 90 percent of the nominal voltage. A Long Duration Voltage Variation is an Overvoltage if the RMS value of the voltage is greater than or equal to 110 percent of the nominal value.

The Licensee and the System Operator shall ensure that the long-duration Voltage Variations result in RMS values of the voltages that are greater than 95 percent but less than 105 percent of the nominal voltage at any Connection Point during normal conditions.

17.2.4 Harmonics

For the purpose of this Section, Harmonics shall be defined as sinusoidal voltages and currents having frequencies that are integral multiples of the fundamental frequency. The Total Harmonic Distortion (THD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the fundamental quantity, expressed in percent.

The Total Demand Distortion (TDD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the rated or maximum fundamental quantity, expressed in percent.

The Total Harmonic Distortion of the voltage and the Total Demand Distortion of the current at any Connection Point shall not exceed the limits given in Tables 17.1 and 17.2, respectively.

Table 17.1: Maximum Harmonic Distortion Factor

Harmonic Voltage Distortion			
Voltage Level	THD *	Individual	
		Odd	Even
400 kV	1.5%	1.0%	0.5%
132-230 kV	2.5%	1.5%	1.0%

* Total Harmonic Distortion

Table 17.2: Maximum Harmonic Distortion Factor

Harmonic Current Distortion			
Voltage Level	TDD *	Individual	
		Odd	Even
400 kV	1.5%	1.0%	0.5%
132-230 kV	2.5%	2.0%	0.5%

* Total Demand Distortion

17.2.5 Voltage Unbalance

For the purpose of this Section, the Negative Sequence imbalance Factor shall be defined as the ratio of the magnitude of the negative sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent. For the purpose of this Section, the Zero-Sequence imbalance Factor shall be defined as the ratio of the magnitude of the zero sequence component of the voltages to the magnitude of the positive sequence component of the voltages, expressed in percent.

The maximum Negative Sequence Unbalance Factor at the Connection Point of any User shall not exceed one (1) percent during normal operating conditions.

The maximum Zero Sequence Unbalance Factor at the Connection Point of any User shall not exceed one (1) percent during normal operating conditions.

17.2.6 Voltage Fluctuation and Flicker Severity

For the purpose of this Section, Voltage Fluctuations shall be defined as systematic variations of the voltage envelope or random amplitude changes where the RMS value of the voltage is between 90 percent and 110 percent of the nominal voltage.

For the purpose of this Section, Flicker shall be defined as the impression of unsteadiness in the visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time.

In the assessment of the disturbance caused by a Flicker source with a short duty cycle, the Short-Term Flicker Severity shall be computed over a 10-minute period.

In the assessment of the disturbance caused by a Flicker source with a long and variable duty cycle, the Long Term Flicker Severity shall be derived from the Short-Term Flicker Severity levels.

The Voltage Fluctuation at any Connection Point with a fluctuating demand shall not exceed one percent (1%) of the nominal voltage for every step change, which may occur repetitively. Any large Voltage Fluctuation other than a step change may be allowed up to a level of threepercent (3%) provided that this does not constitute a risk to the Grid or to the System of any User.

The Flicker Severity at any Connection Point in the Grid shall not exceed the values given in Table 17.3.

Table 17.3: Maximum Flicker Severity

	Short Term	Long Term
132 kV and above	0.8 unit	0.6 unit
below 132 kV	1.0 unit	0.8 unit

17.2.7 Transient Voltage Variations

For the purpose of this Section, Transient Voltages shall be defined as high- frequency Overvoltages that are generally shorter in duration compared to the Short Duration Voltage Variations.

Infrequent short-duration peaks may be permitted to exceed the levels specified in Section 17.2.4 for harmonic distortions, provided that such increases do not compromise service to other end-users or cause damage to any Grid equipment.

Infrequent short-duration peaks with a maximum value of two (2) percent may be permitted for Voltage imbalance, subject to the terms of the Connection Agreement or Amended Connection Agreement.

17.3 RELIABILITY STANDARDS

17.3.1 Criteria for Establishing Transmission Reliability Standards

The Commission shall impose a uniform system of recording and reporting of Grid reliability performance.

The numerical levels of performance (or targets) shall be unique and shall be based initially on the Grid's historical performance.

The Grid shall be evaluated annually to compare its actual performance with the targets

17.3.2 Transmission Reliability Indices

The **Commission** shall prescribe a reliability index that will measure the total number of sustained power interruptions in the Grid. Initially, the following indices will be applicable:

(a) Availability Factor

(b) AACIR: Average Annual Customer Interruption Rate

(c) MTTR: Mean Time to Repair

(d) MTBF: Mean Time Between Failures.

The **Commission** shall prescribe a reliability index that will measure the total duration of sustained power interruptions in the Grid.

After due notice and hearing, the Commission may impose other indices that will monitor the reliability performance of the Grid.

17.3.3 Inclusions and Exclusions of Interruption Events

A power interruption shall include any outage in the Grid that may be due to the tripping action of protective devices during faults or the failure of transmission lines and/or power transformers and which results in the loss of service to a Grid User or a group of Users.

The following events shall be excluded in the calculation of the reliability indices:

(a) Outages that occur outside the Grid;

(b) Outages due to generation deficits;

(c) Planned Outages where the Users have been notified at least seven (7) days prior to the loss of power;

(d) Outages that are initiated by the System Operator or Market Operator during the occurrence of Significant Incidents or the failure of their facilities;

(e) Outages caused by Adverse Weather or Major Storm Disasters that result in the declaration by the government of a state of calamity; and

(f) Outages due to other events that the Commissionshall approve after due notice and hearing.

17.3.4 Submission of Transmission Reliability Reports and Performance Targets

The Licensee and the System Operato**r** shall submit interruption reports every three (3) months using the standard format prescribed by the Commission.

The Commission shall set the performance targets after due notice and hearing.

17.4 SYSTEM LOSS STANDARDS

17.4.1 System Loss Classifications

System Losses shall be classified into three categories: Technical Loss, Non-Technical Loss, and Administrative Loss.

The Technical Loss shall be the aggregate of conductor loss, bus loss, core and copper loss in transformers, and any loss due to technical metering error.

The Non-Technical Loss shall be the aggregate of the Energy loss due to underbilling, meter-reading errors, etc.

The Administrative Loss shall include the Energy that is required for the proper operation of the Grid such as station use, consumption by auxiliaries, etc.

17.4.2 System Loss Cap

The Commission shall, after due notice and hearing, prescribe a cap on the System Loss that can be passed on to the Grid Users.

17.5 SAFETY STANDARDS

17.5.1 Safety Compliance

The Licensee and the System Operator shall develop, operate, and maintain the Grid in a safe manner and shall always ensure a safe work environment for their employees. The Electricity Rules 2020 and revisions thereof govern the safety requirements for electrical installation, operation, and maintenance, which cover electrical equipment and associated work practices employed by the electric utility. Compliance with these Codes is mandatory. Hence, the Licensee and the System Operator shall at all times ensure that all provisions of these safety codes are not violated.

17.5.2 Measurement of Performance for Personnel Safety

The Following pertinent matters are to be ensured for the measurement of performance for personnel safety that shall be applied to the Licensee and the System Operator:

(a) Exposure to work injuries shall be measured by the total number of hours of employment of all employees in each establishment or reporting unit.

(b) Employee hours of exposure for calculating work injury rates are intended to be the actual hours worked. When actual hours are not available, estimated hours may be used.

(c) The Disabling Injury or Illness Frequency Rate shall be based upon the total number of deaths and permanent total, permanent partial, and temporary total disabilities that occur during the period covered by the rate. The rate relates those injuries and illnesses to the employee hours worked during the period and expresses the number of such injuries in terms of a million man-hour units.

(d) The Disabling Injury/Illness Severity Rate shall be based on the total of all scheduled charges for all deaths, permanent total, and permanent partial disabilities, plus the total actual days of the disabilities of all temporary total disabilities that occur during the period covered by the rate. The rate relates these days to the total employee-hours worked during the period and expresses the loss in terms of million man-hour units.

17.5.3 Submission of Safety Records and Reports

The Licensee and System Operator shall submit copies of records and reports to the Commission. These shall include the measurement of performance specified in sub-section 17.5.2.

17.6 ELECTRIC AND MAGNETIC FIELD (EMF)

The **Licensee** shall calculate the intensity of Electric and Magnetic Field (EMF) at the edge of the right of way for different line configurations and operating voltages. The values of Electric Field shall be determined in V/m and those of Magnetic Field in mT (milli-Telsa) or mG (milli-Gauss). Actual intensity shall be practically measured in accordance with IEEE Standard 644 (latest revision), and the finding shall be submitted to the Commission**.** The Safety level with respect to human exposure to electromagnetic field shall also be determined and maintained in accordance with IEEE C95.1 throgh IEEE C95.6 (2002 or the latest revision).

17.7 NOISE LEVEL

The Noise level having its source at Grid substations and the Noise level around the transmission lines shall be in accordance with the Environmental laws of Bangladesh. International standards shall be followed if boundary conditions are missing in the pertinent laws of the country.

18. FINANCIAL STANDARDS

18.1 PURPOSE AND SCOPE

18.1.1 Purpose

(a) To specify the financial capability standards for the Entities listed in sub-section 18.1.2;

(b) To safeguard against the risk of financial non-performance;

(c) To ensure the affordability of electric power supply while maintaining the required quality and reliability; and

(d) To protect the public interest.

18.1.2 Scope of Application

This Chapter applies to the Entities listed below:

(a) The Licensee;

(b) The System Operator;

(c) The Single Buyer**;** and

(d) Distribution Utilities**.**

18.2 FINANCIAL STANDARDS FOR THE ENTITIES

18.2.1 Financial Ratios

The following Financial Ratios shall be used to evaluate the Financial Capability of the Entity:

(a) Leverage Ratios;

(b) Liquidity Ratios;

(c) Financial Efficiency Ratios; and

(d) Profitability Ratios.

18.2.2 Leverage Ratios

Leverage Ratios for the Entity shall include the following:

(a) Debt Ratio;

(b) Debt-Equity Ratio; and

(c) Interest Cover.

The Debt Ratio shall measure the degree of indebtedness of the Entity. The Debt Ratio shall be calculated as the ratio of total liabilities to total assets.

The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Entity cannot pay off interest and principal.

The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases to Long-Term Debt plus Value of Leases plus Equity. Equity is the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

The Debt-Equity Ratio shall indicate the relationship between longterm funds provided by creditors and those provided by the Entity. The Debt-Equity Ratio shall be calculated as the ratio of the sum of longterm Debt plus the Value of Leases to Equity. Equity shall be the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Entity.

The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Entity.

The Interest Cover shall measure the ability of the Entity to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments.

The Interest Cover shall also be used as a measure of financial leverage for the Entity that focuses on the extent to which contractual interest and principal payments are covered by earnings before interest and taxes plus depreciation. The Interest Cover is identical to Debt Service Coverage Ratio because principal payments due during the year are included in the denominator of the ratio.

18.2.3 Liquidity Ratios

Liquidity Ratios shall include the following:

(a) Current Ratio; and

(b) Quick Ratio.

The Current Ratio shall measure the ability of the Entity to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets including inventories to Current Liabilities. Current Assets shall consist of cash and assets that can readily be turned into cash by the Entity. Current Liabilities shall consist of payments that the Entityis expected to make in the near future.

The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Entity.

The Quick Ratio shall measure the ability of the Entity to satisfy its short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities and Receivables to the Current Liabilities.

The Quick Ratio shall be used to measure the safety margin for the payment of the entity's current debt if there is shrinkage in the value of cash and receivables.

18.2.4 Financial Efficiency Ratios

Financial Efficiency Ratios shall include the following:

(a) Sales-to-Assets Ratio; and

(b) Average Collection Period.

The Sales-to-Assets Ratio shall measure the efficiency with which the Entity uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year. The higher the Sales-to- Assets Ratio, the more efficiently the Entity's assets have been used.

The Average Collection Period (ACP) shall measure how quickly other entities pay their bills to the Entity. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. Daily Sales shall be computed by dividing Annual Sales by 365 days.

The Average Collection Period shall be used to evaluate the credit and collection policies of the Entity.

Two computations of the Average Collection Period shall be made:

(a) ACP with government accounts and accounts under litigation; and

(b) ACP without government accounts and accounts under litigation.

18.2.5 Profitability Ratios

Profitability Ratios shall include the following: (a) Net Profit Margin; and (b) Return on Assets.

The Net Profit Margin shall measure the productivity of sales efforts. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT – Tax). The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

The Net Profit Margin shall be used to measure the percentage of sales that remain after all costs and expenses have been deducted.

The Return on Assets shall measure the overall effectiveness of the Entity ingenerating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings before Interest and Taxes minus Taxes to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

18.2.6 Submission and Evaluation

The Entity shall submit to the Commission true copies of the audited balance sheet and financial statement for the preceding financial year on or before October 15 of the current year.

The Entity shall submit to the Commission the average power consumption and revenue income for each class of customers for the preceding financial year. This requirement is due on or before September 30 of the current year.

Failure to submit to the Commission the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.

A duly authorized officer must certify all submissions.

18.3 UNIFORM SYSTEM OF ACCOUNTS (USoAC)

The Entity shall follow the accounting procedures of the Commission namely the Uniform System of Accounts (USoAC), in fulfilling the requirements of the Financial Standard of Transmission stated in this Grid Code.

If Anything in the Financial Standard of Transmission is contradictory to the provisions or procedures of the USoAC, then the provisions or system of the latter shall prevail.

By the order of the Commission

BARRISTER MD. KHALILUR RAHMAN KHAN

Secretary.

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