

**THE GRID CODE
FOR THE
NIGERIA ELECTRICITY TRANSMISSION
SYSTEM**

GRID CODE

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PART 1: GENERAL CONDITIONS (GC)

1. SECTION: BACKGROUND

1.1. TITLE

1.1.1. The Grid Code and guidelines shall be called the Grid Code for the Electricity Industry of Nigeria (the “Code”)

1.2. NEW ARRANGEMENT FOR THE NIGERIAN ELECTRICITY SECTOR

1.2.1. The Electric Power Sector Reform Act, 2005 (henceforth referred to as the Act) gave legal backing to the unbundling of the Nigeria Power Sector. The Act stipulates the functional unbundling of the Generation, Transmission and Distribution Sectors.

1.2.2. Pursuant to Sections 8, 65 and 66 of the Act, a Transmission and System Operating Company (TCN) shall be established and licence to perform the functions of transmission and system operations of the High Voltage network of the Nigerian electricity industry. In addition, TCN shall be responsible for overseeing market operations involving the trading of wholesale energy amongst market Users.

1.3. THE GRID CODE

1.3.1. The Grid Code contains the day-to-day operating procedures and principles governing the development, maintenance and operation of an effective, well co-ordinated and economic Transmission System for the electricity sector in Nigeria.

1.3.2. The code is designed to:

- (a) Facilitate an efficient production and supply of electricity for all Users of the Transmission System and TCN itself, without any act of discrimination between Users or class of Users.
- (b) Facilitate competition in the generation and supply of electricity in the country.

1.3.3. For complete understanding of the operation of the Nigeria Electricity industry post -deregulation, this document have to be read in conjunction with the Market Rules, Distribution Code and other documents relating to other operational aspects of the industry.

1.4. APPLICATION OF THE GRID CODE

1.4.1. The Grid Code shall apply to TCN and Users of the Transmission System. TCN shall be responsible for implementation of the Grid Code. All Users shall comply with the Grid Code and assist TCN in this regard. Users must provide all the required

information and reasonable rights of access, service and facilities necessary for implementation of the Grid Code.

- (a) If any User has any difficulty in complying with any of the provisions of the Grid Code, the User shall immediately, without delay, inform the same to the Nigerian Electricity Regulatory Commission and TCN, and shall remedy his non-compliance promptly.
- (b) Consistent failure in compliance with the Grid Code may lead to disconnection of the User's plant, Equipment or Apparatus.
- (c) The operation of the Grid Code shall be reviewed regularly by the Grid Code Review Panel in accordance with the provisions of the relevant Sections of the Code.

1.5. ROLE OF THE TCN

1.5.1. TCN shall perform two different group of functions in relation to network and system operation activities:

- (a) As Transmission Service Provider (TSP):
 - (i) admit Users in accordance with the Market Rules who satisfy the requirements for admission;
 - (ii) evaluate and accept grid connections;
 - (iii) ensure proper metering at all Connection Points;
 - (iv) obtain necessary information from Users of the Transmission Network to enable it perform adequate planning operations and development of the Transmission Network.
- (b) As System Operator:
 - (i) dispatch Generating Units in accordance with this Code at least cost, on the basis of Nominations by Generators;
 - (ii) procure Ancillary Services and recover the costs of procuring Ancillary Services;
 - (iii) handle Power System emergencies and restore the Power System;
 - (iv) perform Demand forecasting;
 - (v) co-ordinate Generation and Transmission Outages;
 - (vi) supervise compliance with, and enforce, the Grid Code and Market Rules.
 - (vii) test and monitor of Users equipment to ensure their compliance with the Grid Code.
 - (viii) report of scheduled and planned actions and unexpected occurrences such as faults to network Users and the Regulator
 - (ix) procedures for conducting system tests pertaining to the network.

2. SECTION: ORGANISATION AND OBJECTIVES

2.1. OBJECTIVE

2.1.1. The objective of these General Conditions are,

- (a) To establish the conditions applicable to all the Grid Code and , to the extent possible, ensure that the various parts and sections of the Grid Code work together for the benefit of the TSP, System Operator and all Users, and apply consistently to all Users;
- (b) To provide the principles and procedures for the development and application of the Grid Code.
- (c) To establish requirements for monitoring, testing and investigation on whether Users are operating within their design, operating and connection requirements, as specified in this Code, Grid Connection Agreements, Ancillary Services Agreements or any other relevant Agreements between Users and the TCN.

2.2. UNFORESEEN CIRCUMSTANCES

2.2.1. The Grid Code contains procedures for the management of day to day technical situations on the Transmission Network, taking into account a wide range of operational conditions likely to be encountered under both normal and abnormal conditions.

2.2.2. The Grid Code cannot predict and address all the possible operating conditions. Users must therefore understand and accept that the TCN, in such unforeseen circumstances, may be required to act decisively to discharge its obligations under its License condition(s), within the following general principles and priorities.

- (a) As first priority, preserve or restore the integrity of the Transmission System, including the avoidance of breakdown, separation or collapse (total or partial).
- (b) Compliance by the System Operator with the Electric Power Sector Reform Act, conditions in its System Operator Licence, and the Grid Code.
- (c) Preserve the safety of equipment, to prevent damage to Plant and/or Apparatus, and public safety to prevent personal injury.

Users shall provide such reasonable cooperation and assistance as TCN may require in such circumstances.

2.2.3. In case of an unforeseen circumstance that can not be resolved with the general principles defined in the previous condition, the System Operator shall act according to the following:

- (a) The application of a policy aimed at the equitable sharing amongst Users of any temporary restriction that might be necessary in exceptional circumstances, and
- (b) The application of Prudent Industry Practice.

2.2.4. If circumstances not envisaged by the provisions of the Grid Code should arise, the System Operator shall, to the extent reasonably practicable in the circumstances, consult promptly and in good faith with the Panel or all affected Users in an effort to reach agreement as to what should be done. If agreement between the System Operator and the Panel or affected Users cannot be reached in the time available, the System Operator shall determine what shall be done in accordance to this Grid Code

2.2.5. The System Operator shall promptly refer any unforeseen circumstance identified, together with the determinations and interpretations made, to the Grid Code Review Panel for consideration.

2.2.6. Each User shall comply with all instructions given to it by the System Operator following a determination for an unforeseen circumstance or a difference in interpretation, provided that such instructions are consistent with the technical characteristics of the User's System and the principles established in the Grid Code, and do not endanger the safety of its equipment or staff.

2.2.7. Users should note that the provisions of the Grid Code may be suspended in whole or in part during a Security Period as more particularly provided for in the Fuel Security Code, or in accordance with a Civil Emergency Direction issued under a Civil Emergency directive by appropriate authority.

2.3. ENFORCEMENT

2.3.1. The Electric Power Sector Reform Act of 2005 assigns to the Nigeria Electricity Regulatory Commission (NERC) the authority to establish the appropriate technical codes and manuals that may be required for the safe, reliable and efficient operation of the system. Within such powers, the NERC has the authority to establish the initial Grid Code and to approve amendments from time to time, as reviewed by the TCN and affected Users.

2.3.2. The provisions of this Code shall be enforced by the System Operator in accordance with the Rule 46 of the Market Rules, guidelines from the Nigerian Electricity Regulatory Commission, Grid Connection Agreement and relevant industry Rules and Regulation.

2.4. DEFINITIONS

2.4.1. Capitalised words and expressions used in this Code, unless the context otherwise requires, shall have the meaning assigned to them in Appendix 1.

2.5. INTERPRETATION

2.5.1. In this Code, unless the context otherwise requires:

- (a) a reference to a particular Section, subsection, or Appendix is to a section or subsection of, or Appendix to, this Code;
- (b) a reference in a particular Condition or Appendix to a paragraph is to a paragraph of that section or Appendix;

- (c) the table of contents and Section and subsection headings are for convenience only and shall be ignored in construing this Code;
- (d) references to the masculine include the feminine and references in the singular include references in the plural;
- (e) “N” means Naira;
- (f) the word “include” shall be construed without limitation;
- (g) a reference to a “person” includes any individual, partnership, firm, company, corporation (statutory or otherwise), joint venture, trust, association, organisation or other entity, in each case whether or not having separate legal personality;
- (h) a reference to applicable law shall be construed, at the particular time, as including a reference to any modification, extension, re-enactment or replacement thereof then in force;
- (i) a derivative term of any defined or interpreted term or expression shall be construed in accordance with the relevant definition or interpretation;
- (j) a reference to another agreement or any deed or other instrument shall be construed as a reference to that other agreement, deed or other instrument, as the same may have been, or may from time to time be, modified; and
- (k) “In writing” means typewriting, printing, lithography, electronic mail, facsimile and other modes of reproducing words in a legible and non-transitory form.

2.6. DEROGATIONS

2.6.1. If a User finds that it is, or will be, unable to comply with any provision of this Code, then the User shall, without delay, report such non-compliance to the System Operator and the Nigerian Electricity Regulatory Commission (NERC) and shall make such reasonable efforts as are required to remedy such non-compliance as soon as is reasonably practicable.

2.6.2. When the non compliance described in the previous Condition arises upon the issuance of this Grid Code, or a revision to this Grid Code relating to Equipment already connected to the Transmission System or Equipment approved to be connected to the Transmission System where the User has commenced the procurement or works prior to the issuance of this Grid Code or the revision to this Grid Code, and the User believes either that it would be unreasonable (including on the grounds of cost and technical considerations) to remedy such non-compliance or that it should be granted an extended period to remedy such non-compliance, the User shall promptly submit to the System Operator a request for derogation from such provision in accordance with this Section. The burden of proof shall rest with the User to show good reason why it cannot comply.

2.6.3. If TCN finds that it is, or will be, unable to comply with any provision of this Grid Code, then it shall, without delay, report such non-compliance to the NERC and

shall make such reasonable efforts as are required to remedy such non-compliance as soon as is reasonably practicable.

2.6.4. When the non compliance described in section 2.6.3 arises upon the issuance of this Grid Code, or a revision to this Grid Code relating to Equipment already connected to the Transmission System or Equipment approved to be connected to the Transmission System where TCN has commenced the procurement or works prior to the issuance of this Grid Code or the revision to this Grid Code, and TCN believes either that it would be unreasonable (including on the grounds of cost and technical considerations) to remedy such non-compliance or that it should be granted an extended period to remedy such non-compliance, TCN shall promptly submit to the NERC a request for derogation from such provision in accordance with this Section. The burden of proof shall rest with TCN, to show good reason why it cannot comply.

2.6.5. A request for derogation from any provision of this Grid Code shall contain:

- (a) the detail of the Equipment and Connection Point in respect of which derogation is sought and if relevant, the nature and extent of non-compliance;
- (b) the provision of this Grid Code with which the TCN or User that requests the derogation is, or will be, unable to comply;
- (c) the reason for the non-compliance; and
- (d) the remedial actions and the date by which compliance could be achieved (if remedy of the non-compliance is possible).

2.6.6. Every six months, the System Operator shall report to the NERC:

- (a) the list of derogations requested during the past six (6) months, including requests by the TCN, and the status of each request;
- (b) the list of approved derogations during the past six (6) months indicating type of derogation and party; and
- (c) for each approved derogation, the progress of remedial actions in achieving compliance.

2.6.7. On receipt of any request for derogation, the System Operator or the NERC, as applicable, shall promptly consider such a request provided that the System Operator or the NERC considers that the grounds for the derogation are reasonable. In its consideration of a derogation request, the System Operator or the NERC, as applicable, may contact the User or System Operator, to obtain clarifications of the request or request additional information or to discuss changes to the request, and review possible remedial actions to achieve compliance as soon as reasonably practicable.

2.6.8. The System Operator shall:

- (a) keep a register of all derogations which have been granted, identifying the name of the User in respect of whom the derogation has been granted, the relevant provision of this Grid Code and the period of the derogation; and
- (b) on request from the NERC or any User, provide a copy of such register of derogations.

2.6.9. The NERC shall keep a register of all derogations that have been granted to the TCN, identifying the relevant provision of this Grid Code and the period of the derogation.

2.6.10. The NERC may initiate on its own initiative or at the request of the System Operator, or in view of a User complaint, a review of any existing derogations, and any derogations under consideration where a relevant and material change in circumstance has occurred.

2.7. HIERARCHY

2.7.1. In the event of any inconsistency between this Grid Code and the Electric Power Sector Reform Act, or the license of a the TSP or the System Operator or a Licensee that is a User, the ESPR Act 2005 shall prevail to the extent of such inconsistency.

2.7.2. Nothing in this Grid Code is intended to or shall derogate from a Licensee any license obligation.

2.7.3. If any provision of this Grid Code should be found to be unlawful or wholly or partially invalid for any reason, the validity of all remaining provisions of this Grid Code shall not be affected.

2.7.4. If part of a provision of this Grid Code is found to be unlawful or invalid but the rest of such provision would remain valid if part of the wording were deleted, the provision shall apply with such minimum modification as may be:

- (a) necessary to make it valid and effective; and
- (b) most closely achieves the result of the original wording but without affecting the meaning or validity of any other provision of this Grid Code.

2.7.5. In the event of any conflict between the provisions of this Grid Code and any contract, agreement or arrangement between TCN and a User, the provisions of this Grid Code shall prevail unless this Grid Code expressly provides otherwise, provided that in the case of Connection Agreements with Users signed prior to the approval of this Grid Code, the conditions in such agreement shall prevail unless

- (a) the parties agree an amendments: or
- (b) the User registers a non-compliance situation that negatively affects the security of the Transmission System, in which case the User must accept the necessary amendments to ensure full compliance with this Grid Code, except for any derogation.

2.8. DATA AND NOTICES

2.8.1. For the purposes of this Code, “Business Day” means a day other than:

- (a) a Saturday or a Sunday; or
- (b) a public holiday in Nigeria;

2.8.2. References to times of the day in these Rules are to official time in Nigeria.

2.8.3. Any notice required to be given by this Grid Code shall be deemed to have been given or received:

- (a) if sent by hand, at the time of delivery;
- (b) if sent by post, from and to any address within Nigeria, [four (4) Business Days] after posting unless otherwise proven; or
- (c) if sent by facsimile, subject to confirmation of uninterrupted transmission report, or by e-mail, [one hour] after being sent, provided that any transmission sent after [17:00 hours] on any day shall be deemed to have been received at [08:00 hours] on the following Business Day unless the contrary is shown to be the case.

2.9. EFFECTIVENESS

2.9.1. The provisions of this Code shall come into effect upon the satisfaction or fulfilment of the events and matters set out or referred to in Appendix 2 (the “Conditions Precedent”), as declared by the Commission.

3. SECTION: REVIEW PROCESS AND CODE DISPUTES

3.1. REVIEW PANEL

3.1.1. A Grid Code Review Panel (GCRP) shall be formed pursuant to Rule 42 of the Market Rules. This Panel will be in charge of this Grid Code review and amendment.

3.2. AMENDMENTS TO GRID CODE

3.2.1. This Code may be amended in accordance with the provisions of Rule 45 of the Market Rules

3.3. DISPUTES ON THE GRID CODE

3.3.1. Any Dispute relating to, arising out or in connection with this Code between:

- (a) a User and the TSP;
- (b) a User and the System Operator
- (c) a person who applies to be a User and the TSP; and
- (d) between Users,

shall be resolved in accordance with the provisions contained in Rule 43 of the Market Rules.

4. SECTION: MONITORING, TESTING AND INVESTIGATIONS

4.1. GENERAL

4.1.1. The System Operator or the TSP, as correspond, will need to carry out certain monitoring, testing and investigation in respect of the performance and characteristics of Generation and Load plant in order to discharge its responsibilities in respect of the safe, secure and economic operation of the Transmission System and in respect of Generation Dispatch.

4.1.2. In order to achieve the primary objectives, procedures need to be established for the monitoring, testing and investigation for each of the following:

- (a) Whether centrally Dispatched Generating Units comply with Dispatch Instructions;
- (b) Whether Generators are in compliance with registered Availability, Ancillary Services capabilities, operating characteristics and any other data required to be registered by those Generators;
- (c) Whether power quality of Users conforms to the standards and limits agreed upon between the affected parties, with respect to the minimum and maximum fault levels, harmonic current injected limits, harmonic voltage contributions, short-term and long-term voltage Flicker, voltage unbalance, the number and the duration and severity of voltage depressions; and
- (d) Whether Users are in compliance with protection requirements and protection settings, Grid Connection Agreements, Ancillary Services Agreements and other relevant support agreements between Users and the System Operator or the TSP, as correspond..

4.2. MONITORING

4.2.1. Time

Monitoring may be carried out at any time by the System Operator or TSP, as correspond, and may result, without the application of further testing, in the evaluation by the System Operator or TSP of User/Participant non-compliance.

4.2.2. Period

Monitoring may be continuous for a specified or unspecified period and shall be carried out by monitoring, data recording and analysis. It shall not require advance notice from the System Operator or TSP to Users.

4.2.3. Recording and analysis system

Where a data recording and analysis system is used, the System Operator shall inform the Participant that any instrument is being used and, on request from the Participant, shall make available to the Participant information in respect of the data recording and analysis system.

4.2.4. Disputes

Disputes shall be handled according to Rules and Regulations of the GCRP.

4.2.5. Performance parameters

Performance parameters shall be defined according to Rule 46.1 of the Market Rules.

4.2.6. Monitoring systems and procedures

The systems and procedures shall be laid out as defined in the Market Rules.

4.3. TESTING

4.3.1. System Operator's or TSP's right to testing

System Operator's or TSP's may, from time to time, carry out tests to verify that a Participant is complying with its connection conditions and registered operating characteristics in the Registered Information.

The System Operator may:

- (a) Induce controlled Power System Frequency of voltage conditions or variations for the purpose of determining that the Generating Unit's response is in accordance with its registered Availability, Ancillary Service capabilities and operating characteristics, and
- (b) Having given three (3) business days notice, or less where agreed, send a representative to the Participant's site to verify by testing in accordance with the test procedures specified, that the Participant is in compliance with its registered values.

4.3.2. Dispatch Instruction

Tests shall be carried out to a Dispatch Instruction from the System Operator.

A test may require the Participant to carry out specific actions in response to a Dispatch Instruction.

4.3.3. Site attendance

A System Operator or TSP representative shall be allowed at Participant sites in order to carry out tests in accordance with agreed or generic testing procedures.

4.3.4. Results

The results of a test may be derived from the monitoring of performance during the test.

4.3.5. Subcontracting of testing work

If the System Operator or TSP subcontracts testing work on a Participant's site, then the Participant and the System Operator or TSP shall be in agreement on the selection of a suitable subcontractor.

[Note: This provision could be left to the Grid Connection Agreement.]

4.3.6. Confidentiality

Confidentiality according to applicable Market Rules shall be adhered to.

4.4. INVESTIGATIONS

4.4.1. Refer to applicable (Rules 44.2 in the) Market Rules for details on investigations.

4.5. CONSEQUENCES OF MONITORING, TESTING AND INVESTIGATION

4.5.1. Refer to applicable industry rules and regulation (e.g. Rule 44 in the Market Rules) for issues surrounding enforcement of these Conditions.

PART 2: PLANNING CODE (PC)

1. SECTION: PURPOSE AND SCOPE

1.1. OBJECTIVES

1.1.1. The objectives of this Planning Code are:

- (a) To provide the guidelines and address the requirements for the System Operator to perform long-term expansion planning of the Nigerian Transmission System.
- (b) To specify the conditions and guidelines for the Users to provide information to the TSP or the System Operator in order that planning and development of the Nigerian Transmission Network can be undertaken in accordance with relevant Licence Standards.
- (c) To Specify Licence Standards which will be used in the planning and development of the Nigeria Transmission Network.
- (d) To specify the information required by the System Operator from Users in respect of capability of gas-fired generating units to run using alternative fuels and mothballed Generating plants.
- (e) To promote interaction between TSP and Users in respect of any proposed development on the network or Users system that might impact on the performance of the Nigeria Transmission Network or interconnection to the network

1.2. PURPOSE

1.2.1. The Transmission System expansion planning will cater for the connection of new Load/Generation to the Transmission System. It will ensure that the impact of these connections can be handled by the existing Transmission System or, if not, it will identify the need for the required expansion. The planning and development of the Transmission System shall be in accordance with the Transmission Planning Criteria and relevant standards applicable in Nigeria.

1.2.2. Reasons for development: The development of the Transmission System, involving its reinforcement or extension, will occur for a number of reasons including, but not limited to:

- (a) A development on a User's System (e.g. Distribution Company) already connected to the Transmission System;
- (b) The introduction of a new substation or the modification of an existing substation between a User's System and the Transmission System;
- (c) Changing requirements for electricity transmission facilities due to changes in factors such as Demand, Generation, technology Reliability requirements, and/or environmental requirements; and

- (d) A combination of more than one of the above-mentioned developments.

1.2.3. Work involved: The reinforcement or extension of the Transmission System may involve works:

- (a) At a new or existing substation where the User's Plant and/or Apparatus is connected to the Transmission System;
- (b) On new or existing Transmission lines or other facilities which join that substation to the remainder of the Transmission System; and
- (c) On new or existing Transmission lines or other facilities at or between points remote from that substation.

1.2.4. Timing: The time required for the planning and development of the Transmission System will depend on the type and extent of the necessary reinforcement and/or extension work. The time required for obtaining planning permission and servitudes, including any associated hearings, and the degree of complexity in undertaking the new work while maintaining satisfactory security and Quality of Supply on the existing Transmission System.

1.3. SCOPE

1.3.1. The Planning Code apply to the System Operator, TSP and to Users of the Transmission System which in this Part of the Code are:

- (a) Power Stations;
- (b) Distributors;
- (c) Interconnected Parties;
- (d) Customers connected to the Transmission System.

2. SECTION: LOAD FORECAST

2.1. OBJECTIVE

2.1.1. The objective of this section is to specify the Generation and Demand Forecasts the System Operator has to generate for both short to medium term planning and expansion purposes.

2.2. LONG TERM DEMAND FORECAST

2.2.1. Timing and publication: System Operator shall create a new long term (15 years) Demand Forecast for the Transmission Network, at least once every 3 years.

This long term Demand Forecast ,shall be updated yearly, and shall form part of the report on long term expansion planning to be supplied to the Commission pursuant to subsection 3.2.7.

2.2.2. **Demand Forecasts factors:** The System Operator shall take the following factors into account when conducting long term Demand Forecasting:

- (a) Historical Demand data;
- (b) Current and anticipated future land use;
- (c) Population and demographic forecasts;
- (d) Economic growth rates; and
- (e) Other information supplied by Users.

2.2.3. Demand Forecast methodology: System Operator shall use a geographical based Demand Forecast methodology based on the factors in subsection 2.2.2 to produce unbiased forecasts of the Transmission Network Demand into the future.

The methodology shall allow System Operator to perform sensitivity analysis to determine an optimistic, realistic or pessimistic long term Demand Forecast.

3. SECTION: EXPANSION PLANNING

3.1. PLANNING STANDARDS

3.1.1. Transmission Planning Criteria: The System Operator, in consultation with the TSP shall develop comprehensive Transmission Planning Criteria to guide the expansion planning of the Transmission System. The Transmission Planning Criteria shall be approved by the Commission.

3.1.2. The System Operator shall apply the Transmission Planning Criteria and relevant standards in the planning and development of the Transmission System.

3.2. LONG TERM EXPANSION PLAN

3.2.1. Long term Demand Forecast

The System Operator shall use the long term (10 years) Demand Forecast for the Transmission System, pursuant to section 2.2, as input for long term expansion planning.

3.2.2. Refurbishment

The System Operator shall perform refurbishment audits on the existing Transmission System in order to determine the remaining useful life of the Transmission System components.

The System Operator shall generate a refurbishment plan to replace ageing and damaged Equipment.

3.2.3. Analyse current network

The System Operator shall analyse and document the current Transmission System adequacy in accordance with Section 14.5.

3.2.4. Expansion alternatives

The System Operator in collaboration with the TSP shall hold workshops with stakeholders to determine possible alternatives to address the combination of the following inputs:

- (a) Long term Demand Forecast;
- (b) Refurbishment needs; and
- (c) Current Transmission System performance.

3.2.5. Analyse alternatives

The System Operator in collaboration with the TSP shall evaluate the alternatives determined pursuant to subsection 3.2.4 for at least five, ten, and fifteen years into the future. At least the following analysis shall be performed:

- (a) Load flow analysis;
- (b) Fault level calculations;
- (c) Stability studies;
- (d) Reliability studies; and
- (e) Financial analysis.

3.2.6. Based in the analysis performed pursuant subsection 3.2.5 the System Operator shall develop a financially feasible least cost expansion plan that meets the approved planning standards.

3.2.7. Long-term expansion plan report

The System Operator shall document the long-term ten year expansion plan in a report every year. This report shall include at least the following sections:

- (a) Long-term Demand Forecast;
- (b) Long-term Generation Adequacy Forecast;
- (c) Long-term Transmission Network Adequacy Forecast;
- (d) Long-term zonal Supply and Demand Margin
- (e) Long-term Statutory outage plan for transmission infrastructure
- (f) Long-term Refurbishment plan;
- (g) Alternatives (Identification and Analysis);
- (h) Capital program; and
- (i) Financial motivation.

The Commission shall circulate this report to all Users for comments. The Commission will approve the long-term expansion plan once it is satisfied that the System Operator has taken all relevant comments into account.

3.2.8. Approval

The TSP shall be committed to implement the projects listed in the long-term expansion plan (and only these projects) after the Commission has approved the report.

3.3. USER INVOLVEMENT

3.3.1. User's data

The System Operator shall require Users to provide data and information (as detailed in Appendices 6 and 7) on a regular basis, in order for the System Operator to undertake the planning and development of the Transmission System in accordance with international standards. Information received for this purpose shall be treated as Transmission System planning data.

3.3.2. Additional data

The System Operator or the TSP shall require additional data or information from a User when the System Operator considers it necessary. The User shall submit the information to the System Operator without delay. Such information may be required so that the System Operator can:

- (a) Plan and develop the Transmission System in accordance with the relevant standards
- (b) Monitor Power System performance and project Power System performance
- (c) Fulfil its statutory or regulatory obligations.

3.3.3. Plant modification

In planning for the development of the Transmission System, the System Operator or the TSP may require an individual User, or group of Users, to modify or install new plant or apparatus, where the System Operator can reasonably show that it is prudent or necessary to do so. If the work is to be a significant benefit to the User(s), the expenses shall be borne by the User(s) otherwise by the TSP.

3.3.4. Objection

The User(s) may object on grounds that to modify or install new plant or apparatus as required, in accordance with Good Utility Practice, would be technically or financially infeasible. This may include, but shall not be limited to, for example, the installation of Power System Stabilisers.

3.3.5. Closing down

The User(s) shall give the System Operator at least 24 calendar months notice if the User(s) plans to close down, retire or withdraw from service any of its Generating Unit(s), Equipment or Apparatus. It also applies if User(s) ceases to maintain and keep available any Generating Units with registered capacity greater than 10 MW for dispatching.

4. SECTION: DATA REQUIREMENTS FOR LONG TERM PLANNING

4.1. INFORMATION REQUIRED

4.1.1. In order to develop the Long Term Expansion Plan, the System Operator shall use the guidelines and data requirements indicated in Appendices 5, 6, 7 to specify the technical, design criteria and procedures to be applied in the planning and development of the Nigeria Transmission Network. This information shall be taken into account by Users, when the planning and develop their own plant and equipment connected to the network.

4.1.2. For Network Planning, User information required as stipulated in Appendices 5, 6, 7 includes data on:

- (a) Standard Planning Data
- (b) Detail Planning Data
- (c) Network Planning data (Forecast and Registered)
- (d) Connection Planning Data

4.1.3. Standard Planning Data:

This is the data a User whether connected directly or seeking such connection to the Transmission Network shall provide the TSP of its Plant or Equipment at the connection site, which may have impact on the performance of the Nigerian Electricity Network. In addition each Generator in Embedded Power station greater than 1.0MW connected to the Distribution Network shall provide the TSP with fault infeed data as specified in this Code.

User shall provide the TSP a Single Line Diagram, depicting both its existing and proposed arrangement(s) of load current carrying equipment relating to both existing and proposed connection points that can impact on the Network performance.

4.1.4. Detailed Planning Data:

These are additional detail data where it may apply of the Users plant and equipment required by the TSP to conduct further studies if the Users plant and equipment might have serious impact on the Transmission Network or existing Users already connected to the Network before allowing the User to connect to the Network. These data must be provided within 30 business days after request.

4.1.5. Network Planning Data:

The data required in this category is in Appendix 7.

4.1.6. Connection Planning Data:

The Grid Code requires that at the time the TSP signs a Grid Connection and Construction Agreements with the User, estimated values assumed in the Standard Planning Data for planning purposes are confirmed or where practicable replaced by validated actual values. This data is then termed Connection Planning Data. Connected Planning Data is divided into:

- (a) Forecast Data – items in the Standard Planning and Detailed Planning Data that will always be forecast data.
- (b) Registered Data – items in the Standard Planning and Detailed Planning Data which upon connection to the network become fixed (subject to any subsequent changes)

Connection Planning Data and other relevant Data held by the TSP when a new application is made shall form the background against which such application shall be considered and against which planning for the entire network will be based. With the exception of other data, Users Registered Data shall be treated as non confidential.

4.2. STANDARD PLANNING DATA

4.2.1. User's System Layout

Users connected or seeking connection to the Transmission Network shall provide Single Line Diagram, depicting both its existing and proposed arrangement(s) of load current carrying Equipment relating to both existing and proposed Connection Points. The Single Line diagram to be supplied is in addition to the Operation diagram.

The Single Line Diagram must include all parts of the User System operating at Transmission and sub Transmission Voltages at the Connection Site. Such diagram must include all parts of the User's sub-Transmission System operating at voltages greater than 20KV which under either intact Network or Planned Outage conditions:

- (a) normally interconnects separate Connection Points, or busbars at a Connection Point which normally run in separate sections; or
- (b) connects Embedded Power Stations connected to the User's Sub-transmission System to a Connection Point.

The Single Line Diagram should also contain additional details of the User's Subtransmission System not already included above and also details of the bulk power transformers connecting the User's Subtransmission System to a lower voltage, plus points at which demand Data and fault infeed data are supplied.

4.2.2. The Single Line diagram shall include:

Electrical circuitry (i.e. overhead lines, identifying which circuits are on the same towers, underground cables, power transformers, reactive compensation equipment and similar equipment; and

- (a) Substation names (in full or abbreviated form) with Operating Voltages.
- (b) Circuit breakers

(c) Phasing arrangements.

For each circuit shown on the Single Line Diagram, each User shall provide the following details relating to that part of its Users System:

Circuit Parameters:

- Rated voltage (KV)
- Operating voltage (KV)
- Positive phase sequence reactance
- Positive phase sequence resistance
- Positive phase sequence susceptance
- Zero phase sequence reactance (both self and mutual)
- Zero phase sequence resistance (both self and mutual)
- Zero phase sequence susceptance (both self and mutual)

For each transformer shown in the Single line diagram, User shall provide the following:

- Rated MVA
- Voltage Ratio
- Winding arrangement
- Positive sequence reactance (max, min, nominal tap)
- Positive sequence resistance (max, min, nominal tap)
- Zero sequence reactance

In addition for all interconnecting bulk transformers between the User's Transmission Voltage System and the User's Subtransmission System, the User shall supply the following

- Tap changer range
- Tap changer step size
- Tap changer type: on load or off circuit
- Earthing method: direct, resistance or reactance
- Impedance (if not directly earthed)

User shall supply the following about the User's equipment installed at a Transmission Site:

- Switchgear: For all circuit breakers:-
 - Rated voltage (KV)
 - Operating voltage (KV)
 - Rated 3-phase rms short-circuit breaking current (kA)
 - Rated 1-phase rms short-circuit breaking current (kA)
 - Rated 3-phase peak short-circuit making current (kA)
 - Rated 1-phase peak short-circuit making current (kA)
 - Rated rms continuous current (A)
 - DC time constant applied at testing of asymmetrical breaking abilities (rms)

- Substation Infrastructure

(This includes but not limited to switch dis-connectors, dis-connectors, current transformers, line traps, busbars, through bushings etc)

 - Rated 3-phase rms short-circuit withstand current (kA)
 - Rated 1-phase rms short-circuit withstand current (kA)
 - Rated 3-phase peak short-circuit withstand current (kA)
 - Rated 1-phase peak short-circuit withstand current (kA)
 - Rated rms continuous current (A)

- Lumped System Susceptance

For all parts of the User's Subtransmission System which are not included in the Single Line Diagram, each User shall provide the equivalent lumped shunt susceptance at nominal Frequency. This should include shunt reactors connected to cables which are not normally in or out of service independent of the cable (i.e. they are regarded as part of the cable), but not including independently switched reactive compensation equipment connected to the User's System, or any susceptance of the User's system inherent in the Demand (Reactive Power) data specified under this Code.

- Reactive Compensation Equipment

For all independently switched reactive compensation equipment including that shown in the Single Line Diagram, not operated by TCN and connected to the User's System at 33KV and above, the following information is required:

- Type of equipment (fixed or variable)
- Capacitive and/or inductive rating or its operating range in MVA_r
- Details of any automatic control logic to enable operating characteristics to be determined
- The point of connection to the User's System in terms of electrical location and network voltage.

4.2.3. Short Circuit Contribution to the TSP Transmission Network

(a) General

To allow the TSP and System Operator to calculate fault currents, each User's is required to provide data, calculated in accordance with best international practice as set out in this Code.

The data should be provided from the User's System with all Generating Units Synchronised to that User's System. The User must ensure that the pre-fault network conditions reflect a credible System operating arrangement.

The list of data items required, in whole or part under the following provisions is set out in 4.2.4. The fault currents in sub-paragraphs (a) and (b) of the data list in 4.2.4 should be based on a.c. load flow that takes into account any pre-fault current flow across the point of connection being considered.

Where prospective short-circuit currents on equipment owned, operated or managed by the TSP are close to the equipment rating, and in TSP or System Operator reasonable opinion more accurate calculations of the prospective short circuit currents are required, then the TSP may request additional short circuit data.

(b) Data from Directly Connected Customers

Directly Connected Customers at each node on the Single Line Diagram provided to the TSP shall provide motor loads and/or Embedded Small Power Stations and other installations of direct current converters which do not form a DC converter Station assuming a fault at that location, as follows:-

The data items listed under the following parts of 4.2.4

- (a) (i), (ii), (iii), (iv), (v) and (vi)

And the data items shall be provided in accordance to detailed provisions of 4.2.4 (c) – (f).

(c) Data from User's Generating Unit in a Power Station

For User's each Generating Unit in a power Station, with one or more associated Unit Transformer(s), the User is required to provide values for the contribution of the Power Station Auxiliaries (including Auxiliary Gas Turbine or Auxiliary Diesel Engines) to the fault current flowing through the Unit Transformer(s). The data items listed under the following parts of subsection 4.2.4 (a) should be provided:-

(i), (ii) and (v)

(iii) if the associated Generating Unit step-up transformer can supply zero phase sequence current from the Generating Unit side to the Transmission Network

(iv) if the value is not 1.0 p.u.

The data item shall be provided in accordance with the provisions of subsection 4.2.4 (c) –(f).

Auxiliary motor short circuit contribution and any Auxiliary Gas Turbine Unit contribution through the Unit Transformers must be represented as a combined short circuit current contribution at the Generating Unit's terminals, assuming a fault at that location.

If the User's Power Station has separate Station Transformers, data should be provided for the fault current contribution from each transformer at its high voltage terminals, assuming a fault at that location as follows:-

The data items listed under the following parts of 4.2.4

(a) (i) to (vi)

And the data items shall be provided in accordance with the detailed provisions of 4.2.4 (b)-(f)

Data for the fault infeeds through both Unit and Station Transformers shall be provided for the normal running arrangement when the maximum number of Generating Units are Synchronised to the Network. Where there is an alternative running arrangement which can give higher fault infeed through the Station Transformers, then a separate data submission representing this condition shall be made.

No account should be taken of the interconnection between the Station and Unit Board, unless the normal operating arrangement within the Power Station is to have the Station and Unit Boards interconnected within the Power Stations.

Auxillary motor short circuit current contribution through the Station Transformers must be represented as a combined short circuit contribution through the Station Transformers.

4.2.4. Data Items

- (a) Below is the list of data utilised in this part of the Planning Code. It also contains rules on the data which generally apply:-
- (i) Root mean square of the symmetrical three-phase short circuit current infeed at the instant of fault ($I1''$).
 - (ii) Root mean square of the symmetrical three-phase short circuit current after the subtransient fault current contribution has substantially decayed ($I1'$).

- (iii) The zero sequence source resistance and reactance values of the User's Equipment as seen from node on the Single Line diagram provided under 4.2.1 (or Station Transformer high voltage terminals or Generating Unit terminals as appropriate) consistent with the infeed describe in 4.2.1
 - (iv) Root mean square of the pre-fault voltage at which the maximum fault currents were calculated;
 - (v) The positive sequence X/R ratio at the instant of fault
 - (vi) The negative sequence resistance and reactance values of the User's Generating unit seen from node on the Single Line diagram provided under 4.2.1 (or Station Transformer high voltage terminals, or Generating Unit terminals if appropriate) if substantially different from the values of positive sequence resistance and reactance which would be derived from the data provided above.
- (b) In considering this data, unless the User notifies TCN accordingly at the time of data submission, TCN will assume that the time constant of decay of the subtransient fault current corresponding to the change from I_1'' to I_1' (T'') is not significantly different from 40ms. The User must inform TCN if the assumption is not correct in relation to an item of data.
- (c) The value for X/R ratio must reflect the rate of decay of the d.c. component that may be present in the fault current and hence that of the sources of the initial fault current. All shunt elements and loads must therefore be deleted from any system model before the X/R ratio is calculated.
- (d) In producing the data, the User may use "time step analysis" or "fixed-point-in-time analysis" with different impedances.
- (e) If a fixed-in-time analysis with different impedances method is used, then in relation to the data submitted under (a) (i) above, the data will be required for "time zero" to give I_1'' . The figure of 120ms is consistent with a decay time constant T'' of 40ms, and if that figure is different, then the figure of 120ms must be changed accordingly.
- (f) Where a "time step analysis" is carried out, the X/R ratio may be calculated directly from the rate of the d.c. component. The X/R ratio is not that given by the phase angle of the fault current if this is based on a system calculation with shunt loads, but from the Thevenin equivalent of the System impedance at the instant of fault with all non-source shunts removed.

4.3. GENERATING UNIT DATA

4.3.1. Directly Connected Generating Unit

Each Generator owner with an existing, or proposed Power Station directly connected, or to be directly connected, to the Nigerian Transmission System, shall provide the TSP with data relating to that Power Station both current and forecast as specified in 4.3.2 to 4.3.3.

On receipt of this data, the Generator owner may be further required by the TSP or System Operator to provide details of Embedded Power Station data.

Where Generating Units which term includes CCGT Units are connected to the Transmission Network via a busbar arrangement which is or is expected to be operated in separate sections, the section of busbar to which each Generating Unit is connected is to be identified in the submission.

4.3.2. Output Data

Items (a) to (i) listed below shall be supplied by each User for its Generator, in accordance the type of generator involved:

- Large Power Stations and Generating Unit:

Data items in 4.3.2 (a) to (h) are required with respect to each Power Station and each Generating Unit of each Large Power Station and for each Generating unit.

- Embedded Power Stations

Data item in 4.3.2 (a) is required with respect to each Embedded Power Station and Generating Unit.

- CCGT Units/Modules

Data item 4.3.2 (g) is required with respect to each CCGT unit.

Data item 4.3.2 (a) is required with respect to each CCGT Module

Data item 4.3.2 (b), (c), (d) and (e) are required with respect to each CCGT Module unless TCN informs relevant User in advance of the submission that it needs the data item with respect to each CCGT Unit. Where any definition utilised or referred to in relation to any of the data items does not reflect CCGT Units, such definition shall be deemed to relate to CCGT Units for the purpose of these data items.

- Hydro Schemes

Data item in Appendix 5 is required with respect to each Hydro Scheme.

- (a) Data Items:Registered Capacity (MW)
- (b) Output Usable (MW) on a monthly basis
- (c) Network Constrained Capacity (MW) which may be placed on the capacity of an Embedded Generating Unit due to Network Operator's System in which it is embedded. Where the Embedded Generating Units connected to a Distribution Network via a busbar arrangement which is or is expected to be operated in separate sections, details of the busbar arrangements and connected circuits at the substation to which the Embedded Generating Unit is connected must be provided to TCN to

determine where the power generated by the Embedded Generating Unit would appear on the Transmission Network.

- (d) Minimum Generation (MW)
- (e) MW obtainable from User's Generating Units in excess of Registered Capacity.
- (f) Generator Performance Chart:
 - (i) at the Synchronous Generating Unit stator terminals
 - (ii) at the electrical points of connection to the Transmission Network (or User System if Embedded) for a Non Synchronous Generating Unit
- (g) A list of CCGT Units within a CCGT Module, identifying each CCGT Unit and the CCGT Module of which it forms part, unambiguously in the case of a Range CCGT Module, details of the possible configurations should also be submitted, together with details of the single Grid Connection point at which power is provided from the Range CCGT Module including Embedded Range CCGT Module.

(Nothing shall prevent the busbar at the relevant point being operated in separate sections)

- (h) Expected running regime(s) at each Power Station and type of Generating Unit (e.g. Steam Unit, Gas Turbine Unit, Combined Cycle Gas Turbine Unit, etc)
- (i) A list of Power Stations and Generating Units within a cascade Hydro Scheme, identifying each Generating Unit and Power Station and the cascade Hydro Scheme of which each form part unambiguously. In addition:
 - (i) details of the Transmission Network Entry Point at which Active Power is provided, or if Embedded the Transmission Network Supply points within which the Generating Unit is Connected.
 - (ii) where the Active Power output of a User Generating Unit is split between more than one Transmission Network Supply Points the percentage that would appear under normal and Outage conditions at each Transmission Network Supply point.

Without prejudice to paragraph (g) above, identification of CCGT Units within a CCGT Module can only be amended in accordance with the following provision:

If the CCGT Module is a Normal or Range CCGT Module, the CCGT Units within that Module can only be amended if TCN gives its prior consent in writing. Notice of wish to amend the CCGT Units within such CCGT Module must be given at least 6 months before it is wished for the amendment to take effect.

4.3.3. Rated Parameter Data

The following information is required to facilitate an early assessment of the need for more detailed studies:

- (a) For all User's Generating Units – Rated MVA, Rated MW

- (b) For each Synchronous Generating Unit:
 - (i) Short circuit ratio
 - (ii) Direct axis transient reactance
 - (iii) Inertia constant for whole machine), MWsecs/MVA
- (c) For each Synchronous Generating Unit step-up transformer:
 - (i) Rated MVA
 - (ii) Positive sequence reactance (at max, min and normal tap)

4.4. DEMAND AND ACTIVE ENERGY DATA

4.4.1. Introduction

Each User directly connected to the Transmission Network with Demand shall provide TCN with Demand data – historic, current and forecast, as specified in this Code, apply equally to Active Energy requirements as to Demand unless the context otherwise requires.

Data will need to be supplied by

- (a) Users, in relation to Demand and Active Energy requirements on the User's System
- (b) Directly connected Customer in relation to its Demand and Active Energy requirements

4.4.2. Active Power and Energy Demand Data

Forecast daily Demand (Active Power) profiles as specified in (a), (b) and (c) below, in respect of each of the User's System (each summed over the Transmission Network Supply Points in each User System) are required for:

Peak day on each of the User's System giving the numerical value of the maximum Demand (Active Power) that in the Users' opinion could reasonably be imposed on the Transmission Network

- (a) Day of peak demand on the Transmission Network (Active Power) as notified by System Operator
- (b) Day of minimum demand on the Transmission Network (Active Power) as notified by System Operator
- (c) In addition, the total Demand (Active Power) in respect of the time of peak of the Transmission Network Demand in the preceding year for each of the Users System summed over the Transmission Network Supply points, for outturn and weather corrected shall be supplied.

4.4.3. By calendar week 20 TCN shall inform Users of the Transmission Network in writing of the following, for the current year and each subsequent 5 years, which will until replaced by the following year's notification:

- (a) The date and time of the annual peak demand of the Transmission Network Demand

- (b) The date and time of the annual minimum demand of the Transmission Network Demand
- (c) Total Active Demand used on each of TCN or Directly Connected Customers (each summed over all grid Supply Points in each User equipment) in the preceding financial year, together with a prediction of the current financial, is enquired. Each Active Energy submission shall be subdivided into the following categories of Customer tariff:
 - (i) Low Voltage1
 - (ii) Low Voltage2
 - (iii) Low Voltage3
 - (iv) High Voltage
 - (v) Traction
 - (vi) Lighting

In addition, the total User losses and Active Energy provided by Distributed Generators shall be supplied.

4.5. DETAILED PLANNING DATA

4.5.1. Introduction

- (a) Directly Connected

Each User with existing Power Station(s) directly connected or to be directly connected to TCN network shall provide TCN with data relating to the Plant and Equipment, both current and forecast as in 4.5.2 as applicable.

- (b) Embedded

Users with existing or proposed Embedded Power Station(s) shall provide TSP with data relating to the Embedded Power Station(s) both current and forecast.

- (c) Demand

For each User's Generating Unit which has an associated Unit Transformer, the value of the Demand supplied through this Unit Transformer when the Generating Unit is at Rated MW output is to be provided.

Where the Power Station has associated Demand additional to the unit supplied Demand which is supplied from either the Transmission Network or the Generator's User's equipment the Generator User shall supply forecasts for each Power Station of:

The maximum Demand that in the User's opinion could reasonably be important on TCN network or the Generator's User equipment as appropriate;

- (i) The Demand at the time of peak TCN Network Demand;
- (ii) The Demand at the time of minimum TCN Network Demand

By calendar week 20 TCN shall inform Users of the Transmission Network in writing of the following, for the current year and each subsequent 5 years, which will until replaced by the following year's notification:

- (iii) The date and time of the annual peak of the Transmission Network Demand
- (iv) The date and time of the annual minimum of the Transmission Network Demand

4.5.2. Synchronous Generating Unit and Associated control System Data

The following Synchronous Generating Unit and Power Station data should be supplied

- (a) Synchronous Generating Unit Parameters
 - (i) Rated terminal volts (kV)
 - (ii) Rated MVA
 - (iii) Rated MW
 - (iv) Minimum Generation MW
 - (v) Short circuit ratio
 - (vi) Direct axis synchronous reactance
 - (vii) Direct axis transient reactance
 - (viii) Direct axis sub-transient reactance
 - (ix) Direct axis short-circuit transient time constant
 - (x) Quadrature axis synchronous reactance
 - (xi) Quadrature axis sub-transient reactance
 - (xii) Quadrature axis short-circuit sub-transient time constant
 - (xiii) Stator time constant
 - (xiv) Stator leakage reactance
 - (xv) Amature winding direct-current resistance
 - (xvi) Turbogenerator inertia constant (MWsec/MVA)
 - (xvii) Rated field current (amps) at Rated MW and MVA_r output and at rated terminal voltage
 - (xviii) Field current (amps) open circuit saturation curve for Generating Unit terminal voltages ranging from 50% to 120% of rated value in 10% steps as derived from appropriate manufactures test certificates.
- (b) Parameters for Generating Unit Step-up Transformer(s)
 - (i) Rated MVA
 - (ii) Voltage ratio
 - (iii) Positive sequence reactance (at max, min & nominal tap)
 - (iv) Positive sequence resistance (at max, min & nominal tap)
 - (v) Zero phase sequence reactance

- (vi) Tap changer range
- (vii) Tap changer step size
- (viii) Tap changer type-on load or off load
- (c) Excitation Control System parameters
 - (i) Excitation equipment Nominal Response
 - (ii) Rated Field Voltage
 - (iii) No-Load Field Voltage
 - (iv) Excitation Equipment On-Load Positive Ceiling Voltage
 - (v) Excitation Equipment No-Load Positive Ceiling Voltage
 - (vi) Excitation Equipment No-Load Negative Ceiling Voltage
 - (vii) Details of Excitation Equipment describing in block diagram form showing transfer of individual elements
 - (viii) Details of Over-excitation Limiter describe in block diagram form showing transfer functions of individual elements
 - (ix) Details of Under-excitation Limiter describe in block diagram form showing transfer functions of individual elements
- (d) Governor Parameters
 - (i) Incremental Droop values (in %) are required for each Generating Unit as six MW loading points (MLP1 to MLP6).
 - (ii) Governor and associated prime mover Parameters – All Generating Units
 - Governor Block diagram showing transfer function of individual elements including acceleration sensitive elements
 - Governor time Constant (in seconds)
 - Speeder Motor Setting range (%)
 - Average gain (MW/Hz)
 - Governor Deadband – Maximum Setting (\pm Hz), Normal Setting (\pm Hz), Minimum Setting (\pm Hz)

(where the Generating unit governor does not have a selectable deadband facility, then the actual value of the deadband need only be provided)
 - (iii) Governor and associated prime mover Parameters (Steam Units):
 - HP Valve Time Constant (in seconds)
 - HP Valve Opening Limits (%)
 - HP Valve Opening Rate Limits (% /second)
 - HP Valve Closing Rate limits (%/second)

- HP Turbine time Constant (in seconds)
- IP Valve Time Constant (in seconds)
- IP Valve Opening Limits (%)
- IP Valve Opening Rate Limits (% /second)
- IP Valve Closing Rate limits (%/second)
- IP Turbine time Constant (in seconds)
- LP Valve Time Constant (in seconds)
- LP Valve Opening Limits (%)
- LP Valve Opening Rate Limits (% /second)
- LP Valve Closing Rate limits (%/second)
- LP Turbine time Constant (in seconds)
- (iv) Governor and associated prime mover Parameters (Gas Turbine Units):
 - Inlet Guide Vane time Constant (in seconds)
 - Inlet Guide Vane Opening limits (%)
 - Inlet Guide Vane Opening rate limits (%/second)
 - Inlet Guide Vane Closing Rate Limits.(%/second)
 - Fuel Valve constant (in seconds)
 - Fuel Valve Opening Limits (%)
 - Fuel Valve Opening Rates Limits (%/second)
 - Fuel valve Closing rate Limits (%/second)
- (v) Governor and associated prime mover Parameters – Hydro Generating Units
 - Guide Vane Actuator time Constant (is seconds)
 - Guide vane Opening limits (%)
 - Guide vane opening rate limits (%/second)
 - Guide Vane Closing rate Limits (%/second)
 - Water Time Constant (in seconds)
- (vi) Unit Control Options
 - Maximum Droop %

- Normal Droop %
- Minimum Droop %
- Maximum Frequency deadband \pm Hz
- Normal Frequency deadband \pm Hz
- Minimum Frequency deadband \pm Hz
- Maximum output deadband \pm MW
- Normal output deadband \pm MW
- Minimum output deadband \pm MW
- (vii) Frequency settings between which Unit load Controller Droop applies:
 - Maximum Hz
 - Normal Hz
 - Minimal Hz
- (viii) Plant Flexibility Performance
 - Run-up rate to registered capacity
 - Run-down rate from registered capacity
 - Synchronising Generation
 - Regulating range
 - Load rejection capability while still Synchronised and able to supply Load.
- (ix) Response data for Frequency changes

Prior to the Generator being first Synchronised, the MW Loading Points must take the following values:

 - MLP1 Designed Minimum Operating Level
 - MLP2 Minimum Generation
 - MLP3 70% of Registered Capacity
 - MLP4 80% of Registered Capacity
 - MLP5 95% of Registered Capacity
 - MLP6 Registered Capacity
- (x) Primary and Secondary Response to Frequency Fall

Primary and Secondary Response values for a -0.5Hz ramp are required at six MW Loading Points (MLP1 to MLP6) as detailed above.

- (xi) High Frequency Response to Frequency Rise

High Frequency Response values for a +0.5Hz ramp are required at six MW loading points (MLP1 to MLP6)

4.6. TRANSIENT OVER-VOLTAGE ASSESSMENT DATA

4.6.1. Each User is required to provide the following data with respect to the Connection Site, current and forecast, together with a Single Line Diagram if not already provided.

- (a) Busbar layout plan(s), including dimension and geometry showing position of any current and voltage transformers, bushings, support insulators, disconnect switches, circuit breakers, surge arrestors etc. Electrical parameters of any associated current and voltage transformer, stray capacitance, of wall bushings and support insulators, and giving capacitances of circuit breakers,
- (b) Electrical parameters and physical construction details of lines and cables connected at the busbar. Electrical parameters of all plant (e.g. transformer- including neutral earthing impedance or zigzag transformer if any), series reactors and shut compensation equipment connected at that busbar (or to the tertiary of a transformer) or by lines or cables to the busbar;
- (c) Basic insulation levels of all Equipment connected directly by lines or by cables to the busbar,
- (d) Fault levels at the lower voltage terminals of each transformer connected directly or indirectly to the TSP Network without intermediate transformation.
- (e) All transformers operating at 132KV and over, three or five limb cores or single phase units to be specified, and operating peak flux density at nominal voltage.

4.7. USER'S PROTECTION DATA

4.7.1. Protection

The following information is required which relates only to Protection equipment which can trip or inter-trip or close any Connection point circuit breaker or any TCN circuit breaker. This information need to be supplied once and regular update made afterwards.

- (a) Full description, including estimated settings, for all relays and Protection systems installed or to be installed on the User's System;
- (b) Full description of auto-reclose facilities installed or to be installed on the User's System, including type and time delays;

- (c) Full description, including estimated settings, for all relays and Protection systems or to be installed on the Generator, Generator transformer, Station transformer and their associated connections
- (d) Generating Units having (or intended to have) a circuit breaker at the Generator terminal voltage, clearance times for electrical faults within the Generating Unit zone
- (e) Most probable fault clearance time for electrical faults on any part of the User's System directly connected to TCN Network.

4.7.2. Harmonic Studies

In the course of operating the Transmission Network, the System Operator or the TSP will have to evaluate the occurrence of harmonic distortion on the Network or User's Systems, especially when equipment like capacitor banks is involved. For proper evaluation, in respect of the Connection Site, Users are required, to submit as follows data current and forecast data if not already submitted under 4.2.2 for any sub-Transmission System for overhead and underground cable circuits:

- Positive phase sequence resistance
- Positive phase sequence reactance
- Positive phase sequence susceptance

For transformers connecting the User's Subtransmission System to a lower voltage:

- Rated MVA
- Voltage Ratio
- Positive phase sequence resistance
- Positive phase sequence reactance

And at the lower voltage points of those connecting transformers:

- Equivalent positive phase sequence susceptance
- Connection voltage and MVAr rating of any capacitor bank and component parameters if designed as a filter
- Equivalent positive phase sequence interconnection impedance with other lower voltage points
- The minimum and maximum Demand (both MW and MVAr) that could occur
- Harmonic current injection sources in Amps at the Connection voltage points
- Details of traction load (e.g. connection phase pairs, continuous variation with time etc.)

- An indication of which items of equipment may be out of service simultaneously during planned Outage condition

4.7.3. Voltage Assessment Studies

In the course of operating the Transmission Network, System Operator will have to undertake voltage assessment studies on the Network to examine potential voltage instability, Voltage Control co-ordination or calculate voltage step changes. Users are required, to submit as follows data current and forecast data if not already submitted under 4.2.2 for any subtransmission System for overhead and underground cable circuits:

- (a) For User's Subtransmission System
 - Positive phase sequence resistance
 - Positive phase sequence reactance
 - Positive phase sequence susceptance
 - MVA_r rating of any reactive compensation Equipment
- (b) For bulk transformers connecting the User's Subtransmission System to a lower voltage:
 - Rated MVA
 - Voltage Ratio
 - Positive phase sequence resistance
 - Positive phase sequence reactance
 - Tap-changer range
 - Number of tap steps
 - Tap-changer type: on-load or off-circuit
 - AVC/tap-changer time delay to first tap movement
 - AVC/tap-changer inter-tap time delay
- (c) And at the lower voltage points of those connecting transformers
 - Equivalent positive phase sequence susceptance
 - MVA_r rating of any reactive compensation equipment
 - Equivalent positive phase sequence interconnection impedance with other lower voltage points
 - Maximum demand (both MW, MVA_r) that could occur.

4.8. NETWORK DATA

4.8.1. If a User wants to model the TSP Transmission Network, the TSP shall provide the Network data indicated in 4.8.2 to allow the User properly calculate conditions on the Network.

4.8.2. Single and Multiple Point Connection

The TSP, or System Operator as correspond, shall provide User with following data:

- (a) Symmetrical three phase short circuit current infeed at the instant of fault from the TSP System (I_1'')
- (b) Symmetrical three phase short circuit current from the TCN System after the subtransient fault current contribution has substantially decayed(I_1')
- (c) Zero sequence source resistance and reactance values at the Point of Connection, consistent with the maximum infeed below
- (d) Pre-fault voltage magnitude at which the maximum fault currents were calculated.
- (e) Positive sequence X/R ratio at the instant of fault
- (f) Negative sequence resistance and reactance values of the TSP Transmission System seen from the Point of Connection
- (g) Initial positive sequence resistance and reactance values of the two or more sources and the linking impedances derived from a fault study constituting the (p) equivalent and evaluated without the User network and load
- (h) Corresponding zero sequence impedance values of the (p) equivalent

The positive sequence X/R ratio and zero sequence impedance will correspond to the TSP Network only.

PART 3: CONNECTION CONDITIONS

1. SECTION: PURPOSE AND SCOPE

1.1. OBJECTIVE

1.1.1. This Section (Connection Conditions) specifies the minimum technical, design and certain operational criteria which must be complied with by the Users connected to, or seeking connection to the Transmission Network. They also set out the procedures by which the Transmission Service Provider (TSP) will process an application to connection to the Transmission System, seeking to ensure compliance with these criteria as a requirement for the granting of approval for the connection of a User to the Transmission System.

1.1.2. The provisions of the Connection Conditions shall apply to all connections to the Transmission Network:

- (a) existing at the date when this Grid Code comes into effect;
- (b) existing at the date of commencement of the TSP's approval, where these dates precede the date in (a) above; and
- (c) as established or modified thereafter.

1.1.3. The Connection Conditions are designed to ensure that:

- (a) No new or modified connection will impose unacceptable effects upon the Transmission System or on any User network nor will it be subject itself to unacceptable effects by its connection to the Transmission System.
- (b) The basic rules for connection treat all Users, within an equivalent category, in a non-discriminatory fashion.

1.2. PURPOSE

1.2.1. The purpose of this Connection Conditions is:

- (a) to specify the technical, design, and operational criteria at each Connection Point;
- (b) to ensure that there is no undue discrimination in the application of the Grid Code between Users or classes of User;
- (c) to facilitate the use of the Transmission System by any User connected to or seeking connection to the Transmission System, in accordance with a Connection Agreement;

- (d) to define the requirements for a User seeking connection and/or for a modification of the current connection;
- (e) to enable the TSP to develop, maintain and operate the Transmission System in a coordinated and economic manner in compliance with its licence;

1.3. SCOPE

1.3.1. The Connection Conditions apply to the System Operator, TSP and to Users of the Transmission System which in this Connection Conditions are:

- (a) Power Stations;
- (b) Distributors;
- (c) Interconnected Parties;
- (d) Customers connected to the Transmission System.

2. SECTION: TRANSMISSION SYSTEM PERFORMANCE CHARACTERISTICS

2.1. FREQUENCY AND VOLTAGE

2.1.1. In order to maintain the security and integrity of the Transmission System it is necessary that the System Operator operate the Transmission System and Dispatch it in such a manner in order to provide adequate Frequency Control so as to achieve operation within applicable Frequency limits at all times.

2.1.2. The nominal Frequency of the system will be 50 Hz. The National Control Centre will endeavour to control the System Frequency within a narrow operating band of $\pm 0.5\%$ from 50 Hz, but under System Stress the Frequency on the Power System could experience variations within the limits of 50 Hz $\pm 2.5\%$ (48.75 – 51.25 Hz).

2.1.3. All equipment and apparatus connected directly or indirectly to the National Grid must operate at 50Hz frequency mode.

2.1.4. Under extreme system fault conditions all Generating Units should disconnect by following frequencies unless agreed otherwise in writing with the System Operator.

- (a) By a frequency greater than or equal to [51.75] Hz.
- (b) By a frequency less than or equal to [48.5] Hz.

2.1.5. The System Operator shall endeavour to control the different busbar voltages to be within the Voltage Control ranges specified in Table1:

Voltage level	Minimum Voltage kV (pu)	Maximum Voltage kV (pu)
330 kV	313.5 (0.95)	346.5 (1.05)
132 kV	118.8 (0.9)	145.0 (1.098)
33 kV	31 (0.94)	34.98 (1.06)
16 kV	15.2 (0.95)	16.8 (1.05)
11 kV	10.45 (0.95)	11.55 (1.05)

Table 1: Voltage Control ranges

Under System Stress or following system faults, voltages can be expected to deviate outside the above limits by a further $\pm 5\%$ (excluding transient and sub-

2.1.6. transient disturbances)

2.1.7. Due to the effect of travelling waves on the Transmission Network as a result of atmospheric disturbances or the switching of long transmission lines, transient over-voltage can occur at certain node points of the network concerned. The insulation level of all Apparatus must be coordinated to take account of transient over-voltages and sensitive User equipment, such as computer and other solid state equipment, should be suitably isolated from this effect.

2.1.8. The transient over-voltage during lightning strikes is typically experienced over a voltage range of $\pm 20\%$ of nominal voltage. Connection Points close to a network lightning strike will experience voltages higher than this.

2.1.9. Unless otherwise agreed by the TSP, the Basic Insulation Value (BIV) for User Apparatus shall be as follows:

- (a) For the 330 kV system, the BIV is 1300 kV.
- (b) For the 132 kV system, the BIV is 650 kV.

2.2. VOLTAGE PERTURBATIONS

2.2.1. "Voltage Flicker" is a rapid change in voltage that is typically caused by User equipment that distorts or interferes with the normal sinusoidal voltage waveform of the Transmission System. Such interference is a product of a relatively large current inrush when Apparatus, such as a large motor, is suddenly switched on, or resulting from the sudden increased demand from for example welding equipment. Such distortions can disturb Users equipment and cause, for instance through flickering lights, consumer annoyance. The current inrush acting over the network impedance is the mechanism that produces the voltage dip (sudden fall) and the corresponding voltage swell (sudden rise) when the Apparatus concerned is offloaded. Hence, the cause of the "Voltage Flicker".

2.2.2. Users are required to minimise the occurrence of Voltage Flicker on the Transmission System as measured at the User's Connection Point. The Flicker Severity at the Connection Point of any User, shall not be above the maximum values stated in IEC 61000-3 Standard for more than 3 % of the period. The maximum emission limits produced by any User shall be below the maximum values stated in IEC 61000-3 Standard,

2.2.3. In cases where, in the reasonable opinion of the System Operator, variations in generation or demand constitute a risk to Transmission System operation, strict conformity with the IEC 61000-3-7 flicker curve will be required.

2.2.4. Harmonics are normally produced by User's Apparatus generating waveforms that distort the fundamental 50 Hz wave. Such harmonic generation can damage User Apparatus and can result in failure of Transmission System Apparatus. The limits for harmonic distortion levels are given in the following documents:

- (a) EN 50160:2000 "Voltage characteristics of electricity supplied by public distribution systems".
- (b) IEC/TR3 61000-3-6 (1996) "Assessment of emission limits for distorting loads in MV and HV power systems".

2.2.5. In general, the maximum total levels of harmonic distortion on the System under Normal Operation conditions, planned outages and fault outage conditions (unless during System Stress) shall not exceed following values:

- (a) 330 kV a Total Harmonic Distortion of 1.5% with no individual harmonic greater than 1%
- (b) 132 kV a Total Harmonic Distortion of 2% with no individual harmonic greater of 1.5%.

2.2.6. Under Normal Operation, the maximum negative phase sequence component of the phase voltage of the Transmission System should remain below 1%.

2.2.7. Under planned outage conditions, infrequent short duration peaks with a maximum value of 2% are permitted for phase unbalance.

3. SECTION: CONNECTION PROCESS

3.1. APPLICATION FOR CONNECTION

3.1.1. Application. Users proposing a connection to the Transmission System, either through a new substation, a modification of an existing substation, or in an existing substation shall send an application to the TSP. If this demand for new connection falls outside the approved Regulatory Long Term Transmission Plan, the cost for such works shall be borne by the User.

3.1.2. Application information: User(s) shall submit the application on an application form when making an application for a connection to the Transmission System. Amongst other information, the application form shall include:

- (a) A description of the Plant or Apparatus to be connected to the Transmission System or, the modification relating to the Participant's Plant or Apparatus already connected to the Transmission System
- (b) Confirmation that the User's Plant and Apparatus at the Connection Point will meet the required technical standards in this Grid Code, and safety regulation as agreed with the TSP where appropriate.
- (c) The technical data (as stipulated in Appendices 5, 6, 7) anticipated for the User's modified or new Plant or Apparatus, specifying the Load characteristics and other data. The TSP shall compile a standard list of detail required from the Participant; and
- (d) The desired connection date and operational date of the proposed User's development.
- (e) A proposed commissioning schedule, including commissioning tests, for the final approval of the System Operator and/or the TSP.

3.1.3. Preliminary planning data: Data supplied in the application form or data submitted along with the application form that is directly relevant to the application and has been submitted in support of it shall be treated as preliminary planning data until such time as the offer for a connection has been made and accepted.

3.1.4. To allow adequate time for consideration of the request, the User shall make this application well in advance prior to the proposed connection date, and in any case less than 3 months of such date. It shall be taken into account that typical time periods required by TCN to undertake the execution of Transmission System expansion projects necessary for a new connection are:

- (a) overhead transmission lines – 18 months; and
- (b) substation – 24 months.

3.1.5. Planning data: Transmission System planning data, together with other data held by the TSP relating to the Transmission System shall form the basis from which new applications by any User shall be considered and from which planning of the Transmission System shall be undertaken. Transmission System planning data shall not be treated as confidential to the extent that the TSP is obliged to:

- (a) To use it in the preparation of the forecast;
- (b) To use it when considering and/or advising other Users;
- (c) To use it for the TSP planning purposes; and
- (d) Under the terms of an Interconnection Agreement to pass it on as part of system information on the Power System.

3.1.6. Type of data: Transmission System planning data is divided into the following type of data:

- (a) Which will always be forecast, known as forecast data;
- (b) Which upon connection becomes fixed, known as Registered Information; and
- (c) Which relate to Plant, Equipment or Apparatus for the purposes of the plant concerned as at the date of submission, known as Registered Information, but which for the ten succeeding years shall be an estimate of what is expected, known as estimated Registered Information.

Actual data: User(s) shall supply the TSP with all outstanding data (as stipulated in Appendices 6, 7) not later than the operational date if not previously requested by the TSP. This shall include confirming any estimated values assumed for planning purposes or, where practical, replacing them by validated actual values and by updated estimates for the future and by updating forecasts for forecast data items.

3.1.7. Additional information: The TSP shall request that a User supply additional information, as the TSP deems necessary to verify the accuracy of the data received, which in the opinion of the TSP is incorrect.

3.1.8. Tests for data verification: The TSP or the System Operator shall request that the User carry out specific tests, at the User's expense, to verify the data, if it maintains that the additional information is insufficient to verify the accuracy of the original. Where such a test or tests are requested, they shall be subject to the provisions of the relevant section of the Grid Codes.

3.1.9. Costs for tests: The TSP shall carry all costs incurred as a result of the test or tests in the event that the initial data as submitted by the User is verified by the test or tests to be correct.

The User shall carry all costs incurred as a result of the test or tests in the event that the data as submitted by the User is verified by the test or tests to be incorrect. If the TSP has to redo or perform additional system studies then the User shall also bear the costs reasonably incurred as a result of the said additional work.

3.2. PROCESS OF THE APPLICATION

3.2.1. The TSP shall establish a procedure for the processing of applications for connection or modification of an existing connection to the Transmission System, which shall include the time frames required to process the application and to submit the User an offer for connection. This procedure will be approved by the NERC.

3.2.2. System studies: Based on the data supplied by the User, the TSP will coordinate with the System Operator to perform the system impact studies required to evaluate in detail the impact of the proposed User development on the Transmission System. (The magnitude and complexity of any Transmission System extension or reinforcement varies according to the nature, location and timing of the proposed User(s) development.).

3.2.3. User(s) studies: Upon request of the User, the TSP shall provide to the User adequate and sufficient information regarding the Transmission System, to enable the User conduct Impact Studies on the User's system, and/or the Transmission System it considers appropriate.

3.2.4. Plant parameters: The User(s) shall provide the TSP with all the relevant Plant or Apparatus parameters as required from Appendices 5, 6, 7 before TCN shall proceed with the above-mentioned System studies.

3.2.5. During the application for connection process, based on the results of the System Studies, the TSP will agree with the User the voltage level and point of connection to the Transmission System. The TSP may, eventually, specify a different Connection Point or connection voltage in order to avoid potential disturbance caused by the User's Equipment to other Users of the Transmission System or for other technical reasons, or may agree alternative methods for minimizing the effects of disturbing loads.

3.2.6. In determining the point of connection, including the voltage level, following aspects shall to be taken into consideration:

- (a) No discrimination: In assessing the technical requirements of a User's connection, the TSP shall not unfairly discriminate between Users of a similar category, location or size although it shall be technically or economically practicable to achieve uniformity of method of connection at all times.
- (b) Generator voltage level: The Transmission System voltage level and the busbar configuration at which a Generator shall be connected to the Transmission System shall depend upon, but shall not be limited to the following:
 - (i) The size of the Generating Units and the number of Generating Units comprised in the Participant's System;
 - (ii) Consistency with future development of the Transmission System;
 - (iii) Proximity to the existing Transmission System; and
 - (iv) The cost of the proposed connection.
- (c) Customer voltage level: The Transmission System voltage level at which a Customer shall be connected to the Transmission System shall depend upon, but shall not be limited to the following:
 - (i) The size of the Active Power Demand at the Connection Point;
 - (ii) Consistency with future development of the Transmission System;
 - (iii) Proximity to the existing Transmission System; and
 - (iv) The cost of the proposed connection.

- (d) Distribution voltage level: The Transmission System voltage level at which a Distributor shall be connected to the Transmission System shall depend upon but shall not be limited to the following:
 - (i) The size of the Active Power Demand at the Connection Point;
 - (ii) Consistency with future development of the Transmission System;
 - (iii) Consistency with co-ordinated planning of the Transmission System and of the Distribution System;
 - (iv) Proximity to the existing Transmission System; and
 - (v) The cost of the proposed connection.
- (e) Method of connection: The method of connection used may exceed the relevant standards where this is required by the User and shall be acceptable to the TSP.

3.2.7. After evaluating the application submitted by the User, the TSP shall inform the User whether the proposed application is acceptable or not. The TSP may disapprove an application for connection or a modification of an existing connection to the Transmission System only if it is determined through the System Studies that the proposed connection or modification do not fulfil the technical requirements or result in the degradation of the Transmission System.

If the application of the User is not acceptable, the TSP shall notify the User as to why its application is not acceptable. The TSP shall include in its notification details of the amendments required to make the User's application acceptable to the Transmission System. The TSP shall immediately report any rejected application to the NERC.

3.2.8. Offer detail: In case the application is accepted, the TSP shall submit to the User an offer to connect to the Transmission System. This Connection Offer shall include, but shall not be limited to, the following:

- (a) Details of how the connection shall be made, including details of the plant and apparatus that shall be required to implement the connection;
- (b) A description of any modification that the applicant Participant shall be required to pay for;
- (c) An indication of the connection date and the operational date; and
- (d) An estimate of the charges for connection.

3.2.9. Acceptance of the offer: A connection offer shall provide that the applicant Participant accepts it within the period stated in the offer, which shall never be less than 45 days, after which the offer shall automatically lapse. Acceptance of the offer shall be affected by execution of the Grid Connection Agreement by both parties, which renders the TSP works relating to that Participant development committed and shall bind both parties in accordance with its terms. The User shall supply the data pertaining to the User's development within sixty (60) business days of acceptance of the connection offer.

3.2.10. Committed planning data: Once a connection offer has been accepted, all data supplied in the application form and any other data submitted along with the application form, shall be treated as committed project planning data.

3.3. CONNECTION AGREEMENT

The acceptance by the User of the TSP proposal shall lead to the signing of a Grid Connection Agreement. If the TSP and the User cannot reach agreement on the proposed connection, or modification to an existing connection, the User shall have the right to bring the matter before the NERC for resolution. The NERC shall have the reasonable right of access to any information that it deems fit in order to resolve such disagreement.

3.3.1. Before entering into a Connection Agreement and before connecting a User's System at a Connection Point, it will be necessary for the TSP to be reasonably satisfied that the User's System at the boundary with the Transmission System will comply with all appropriate requirements of this Grid Code.

3.3.2. The Connection Agreement is a site specific Agreement between TSP, System Operator and Users of the Transmission Network. The agreement shall cover all technical issues involving connection, energisation and operation of generating units connected to the Transmission Network and or centrally despatched by the System Operator. Amongst other topics, the Agreement shall cover the following areas:

- (a) Construction or upgrading of substation and /or Transmission Network
- (b) Connection of Generating Unit or Equipment to substation and / or Transmission Network
- (c) Commissioning, Decommissioning of Generating Units or Equipment
- (d) Commercial and Technical Boundaries
- (e) Protection and Control, Metering.
- (f) Ownership boundaries and access
- (g) Operational diagrams
- (h) Connection Charges.
- (i) Supplementary Agreements – Use of System, Ancillary Services and Interface
- (j) Emergency operations, Health and Safety.
- (k) Reporting and recording of incidence at site.
- (l) Emergency, Force Majeure, Disputes Resolution

The Connection Agreement shall include, and shall not be limited to, provisions for the submission of information and reports, Safety Rules, Test and Commissioning programs, electrical diagrams, statement of readiness to connect, certificate of approval to connect, and other requirements agreed between the parties.

4. SECTION: TECHNICAL CRITERIA FOR PLANT AND APARATUS AT THE CONNECTION POINT

4.1. GENERAL

4.1.1. At the Connection Point all User's Plant and Apparatus shall meet acceptable technical design and operational criteria. Detailed information relating to a particular connection will be made available by the TSP on request by the User. Such information will include, but not be limited to, the following:

- (a) Load flow studies.
- (b) Short circuit studies.
- (c) Power System stability analysis.
- (d) Annual/monthly load curves.
- (e) Line forced outage rates, for the network associated with the proposed Connection Point.
- (f) Telecommunications network associated with the proposed Connection Point.

4.1.2. All Plant and Apparatus connected to or proposed for connection to the Transmission System is required to meet relevant current international or approved standards such as IEC, ISO, EN.

Furthermore, Plant and Apparatus shall be designed, manufactured and tested in accordance with IEC or equivalent approved standard, and quality assurance requirement of ISO 9001 or equivalent.

The User shall ensure that the specification of Plant and Apparatus at the Connection Point or CTP shall be such to permit operation within the applicable safety procedures agreed between the User and TSP.

4.2. SCADA, MEASUREMENT AND DATA EXCHANGE

4.2.1. Technical facilities shall be installed on all interconnecting networks between different party's networks and different Control Areas for exchange of the following information to both parties in real time:

- (a) Status indications of circuit breaker, isolator switches, and earth switches
- (b) Analogue measurement of active and reactive power flow, voltages and Frequency
- (c) Selected protection information.

4.2.2. The above information shall be made available to all Control Centres that have a responsibility to monitor or control the applicable network or is affected by the operation thereof.

4.2.3. Requirements: The technical facilities provided shall adhere to the following minimum requirements:

- (a) Double bit status indications measurement;
- (b) Three phase Active Power and Reactive Power measurement;
- (c) Single-phase Voltage measurement; and
- (d) Support open SCADA protocols to allow interface with other vendor's Equipment.

4.2.4. Recording facilities: Transient recording Facilities shall be installed on the Interconnecting feeder networks between different parties that are Synchronised to the Universal Time Co-ordinated reference time (UTC time).

4.2.5. Power interchange: Each Control Centre responsible for a Control Area shall provide the Facilities to schedule the power interchange with other Control Areas effectively on a frequent and continuous basis.

4.3. TELECOMMUNICATION INSTALLATIONS

4.3.1. Telecommunication facilities at Control Centres: Each Control Centre shall install adequate and reliable telecommunication facilities for their own needs and those of other parties to ensure that the effective exchange of information necessary to maintain the Reliability of the Interconnected network can take place. Wherever possible, there will be back-up facilities and route diversity.

4.3.2. Hot Line: Direct telecommunication channels ("Hot Line") shall be provided between a Control Centre and the Control Centre of each adjacent network, Generators within the Control Area, and co-ordination centres.

4.3.3. Alternative telecommunication channels: Alternate and physically independent telecommunication channels shall be provided to back up the direct circuits, including a Switched Voice Circuit via the Transmission System network, as well as a Switched Voice Circuit via the public telecommunications network where available.

4.3.4. Data communication: Data communication channels shall be provided to support the metering, SCADA, and protection systems. Automated channel monitoring and failure alarms shall be provided for protection communication channels if such failure can cause undesired protection operation.

4.3.5. Voice recording: A voice recording system shall be provided in each Control Centre to record all voice communications between Operators during network operation. The recording of these voice communications should be kept at least 2 months for references when needed.

4.3.6. Communication system Reliability and Availability: The Reliability and Availability of the communication system(s) shall be of acceptable quality levels and in accordance with the prevailing telecommunication standards.

4.4. POWER SYSTEM CONTROL

4.4.1. Generator installations: Technical facilities must be installed on all Generator networks to provide the following information to the responsible Control Centre:

- (a) Status indications of circuit breaker, isolator switches, and earth switches insofar as they are required for operation of the network
- (b) Measurement of Active and Reactive Power flow in both the import and export directions, as well as voltages and Frequency
- (c) Where applicable, reference values for control (activation/deactivation of primary/secondary control) and instantaneous Demand value of the secondary control.
- (d) Reference value of the Reactive Power in the form of the schedule or as an instantaneous value (e.g. for voltage and Reactive Power control).
- (e) Selected protection information

4.4.2. Generator Control Centre: The Control Centre of each Generator shall provide the facilities to effectively schedule the power interchange with the Control Centre of the Interconnected network.

4.5. PROTECTION CRITERIA AND METERING

4.5.1. Minimum protection requirements: The minimum requirements for any new and existing connection will vary depending on many factors such as Load type, earthing methods and others. However, the minimum requirements shall encompass three-phase over current, earth fault (to suite earthing requirements); and inter-tripping.

4.5.2. International standards: All protective schemes and systems shall be in accordance with internationally accepted standards, philosophies and performance (e.g. IEC)

4.5.3. Protection schemes: Protection schemes shall be designed for reliable clearing of all network faults in an effective manner and within an acceptable time duration, and shall be secure against unwanted operation for out-of-zone faults, brief overloads, transient surges or power swings.

The requirements for inter-tripping of protection Apparatus at the Connection Point shall be coordinated between the User and the TSP. This shall be specified in the respective Connection Agreement.

4.5.4. Fault Clearance Times: Fault clearance times at the Connection Point and the method of system earthing including, where relevant, the recommended generator neutral earthing configuration, will be provided by the TSP on request.

Typical fault clearance times for main protection scheme(s) are as follow:

- (a) 60 ms for faults cleared by busbar protection at 330 kV, and 132 kV.
- (b) 80 ms for faults cleared by distance protection on 330 and 132 kV overhead lines.

- (c) 80 ms for faults cleared transformer protections on HV transformers

Total fault clearance time shall be from fault inception until the time to arc extinction, which therefore includes relay operation, circuit breaker operation and telecommunications signalling times.

4.5.5. Users will be expected to coordinate their protection times according to the clearance times specified by the TSP. Prospective Users whose proposed protection scheme cannot achieve these times, or whose Power Station cannot continue operations, whilst line faults on the Transmission System are cleared, may be required to resubmit their proposals for final approval by the TSP.

4.5.6. Protection philosophy: Each party shall implement the prevailing protection philosophy, standards and preventive maintenance procedures that shall improve their system Reliability with the least adverse effects on the interconnected network.

4.5.7. Grading: All protective schemes and all modifications to existing protective schemes that affect the neighbouring system in any way shall be technically co-ordinated and graded with the other party's System.

4.5.8. Back-up protection: Backup protection facilities shall be provided in accordance with the prevailing protection standards in case of the main protection failing to operate.

4.5.9. Network stability and integrity: High speed relays, high speed circuit breakers and automatic re-closing Facilities shall be used where studies show that their application shall enhance the network Stability. Automatic re-closing, under out-of-step conditions shall be prevented by blocking relays.

Under Frequency Load Shedding relays shall be co-ordinated to ensure system Stability and integrity.

4.5.10. Metering: Metering installations at the Connection Point shall be designed in accordance with the Metering Code.

4.6. ADDITIONAL REQUIREMENTS FOR POWER STATIONS

Performance Requirements

4.6.1. The Generating Units shall have, at least, following performance requirements:

- (a) Each Generating Unit must be capable of supplying rated power output (MW) at any point between the limits of 0.85 power factor lagging and 0.95 power factor leading, at the Generating Unit terminals at rated voltage level in the Transmission Network.
- (b) Each Generating Unit must be capable of continuously supplying its registered output within the Power System frequency range given in 2.1.2.
- (c) The Active Power output under steady state conditions of any Generating Unit directly connected to the Transmission Network should not be affected by voltage changes in the normal operating range. The Reactive Power output of a Generating Unit having a synchronous alternator must, under steady state

conditions, be fully available within the voltage range $\pm 10\%$ of nominal voltage at the Connection Point.

- (d) A Generating Unit having a synchronous alternator must be capable of start-up, synchronize and pick up load:
 - (i) From cold, within 10 hours.
 - (ii) From warm, within 6 hours.
 - (iii) From hot within 3 hours.
- (e) A steam-turbine or gas-turbine Generating Unit which has been synchronised must be capable of ramping up pursuant to a Dispatch instruction at a rate of at least 3% of GCR per minute. A steam-turbine or gas-turbine Generating Unit must be capable of de-loading at a rate of at least 3% of GCR per minute.

4.6.2. All steam turbine Generating Units must be fitted with a turbine controller, which is designed and operated to the requirements of IEC 60045, or equivalent standards. All gas turbine Generating Units must be fitted with a turbine speed controller capable of power related speed droop characteristic of between 4% and 6%.

Each steam turbine and gas turbine Generating Unit must be fitted with a fast acting “Turbine Controller”. The turbine speed control principle shall be that the Generating Unit output shall vary with rotational speed according to a proportional droop characteristic (“Primary Control”). Superimposed Load control loops shall have no negative impact on the steady state and transient performance of the turbines rotational speed control.

The Turbine Controller shall be sufficiently damped for both isolated and interconnected operation modes. Under all operation conditions, the damping coefficient of the Turbine Speed Control shall be above 0.25 for speed droop settings above 3% for gas turbines and 5% for steam turbines. For generator oscillations with frequencies below 2 Hz, the Turbine Controller shall have no negative effect on generator oscillation damping.

The Turbine Speed Controller and any other superimposed control loop (Load control, gas turbine temperature limiting control, etc.) shall contribute to the Primary Control to maintain the unit within the Generating Unit Capability Limits.

The Primary Control characteristics shall be maintained under all operational conditions. Additionally, in the event that a Generating Unit becomes isolated from the System but is still supplying Demand the Generating Unit must be able to provide Primary Control to maintain Frequency and voltage.

4.6.3. A continuous “Automatic Voltage Regulator” (AVR) acting on the excitation system is required to provide constant terminal voltage of the Generating Unit without instability over the entire operating range of the Generating Unit. Control performance of the voltage control loop shall be such that under isolated operating conditions the damping coefficient shall be above 0.25 for the entire operating range.

The Automatic Voltage Regulator (AVR) shall have no negative impact on generator oscillation damping. If required the appropriate Power System Stabiliser (PSS) shall be provided. Control principle, parameter setting and switch on/off logic shall be coordinated with the System Operator and specified in the Connection Agreement.

4.6.4. Each Generating Unit shall be required to withstand, without tripping, the negative phase sequence loading experienced during clearance of a close-up phase-to-phase fault, by System back-up protection on the Transmission Network.

4.6.5. The System frequency could rise to 51.5 Hz or fall to 47.5 Hz and Generating Units must continue to operate within this frequency range unless the System Operator has agreed to any frequency-level relays and/or rate-of-change-of-frequency relays which shall trip such Generating Units within this frequency range, as stated in the Connection Agreement.

Power Producers shall be responsible for protecting all their Generating Units against damage should System frequency variations exceed 51.5 Hz or go below 47.5 Hz or such limits agreed with the System Operator. In the event that such variations occur, the Power Producer shall disconnect the Generating Unit for reasons of safety of personnel, Apparatus, and/or Plant.

Protection Arrangements

4.6.6. Each connection between a Generating Unit and the Transmission Network must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the point of connection as determined by the System Operator and/or the TSP.

4.6.7. The System Operator and/or the TSP shall provide each Power Producer at each Connection Point where its Power Station is connected with the appropriate voltage signals to enable the Power Producer to obtain the necessary information to synchronise its Generating Units to the Power System.

4.6.8. Electrical protection of the Generating Unit shall take precedence over operational controls (e.g. Voltage Controllers, excitation equipment) and the Generating Unit shall disconnect from the network should unacceptable Operational States arise as a result of failure of the operational controls. This shall apply in particular when spontaneous faults occur (e.g. earth faults, short-circuits).

4.6.9. The settings for the electrical protective equipment must be agreed upon between the System Operator and the Power Station, and reflected in the Connection Agreement. The possibility of protective and switchgear failures must also be taken into account. Consideration must be given to the following points:

- (a) External short-circuits
- (b) Load unbalance
- (c) Stator and rotor overload
- (d) Under-excitation
- (e) Over Frequency, under Frequency
- (f) Asynchronous operation
- (g) Torsional strain
- (h) Drive failure (operation as motor)
- (i) Measures against breaker failure
- (j) Back-up protection.

4.6.10. To cater for the possibility that the indicated fault clearance times are not met as a result of failure in the operation of the main protection system(s), the Power Station shall provide the necessary back up protection. The TSP shall also provide back up protection which shall be coordinated to provide discrimination and protect equipment from damage.

4.6.11. Where System requirements dictate, the TSP and/or the System Operator shall specify in the Connection Agreement a requirement for Power Producers to fit pole slipping protection on their Generating Units.

Work on Protection Apparatus at the Connection Point

4.6.12. No busbar protection, circuit breaker fail protection relays, AC or DC wiring may be worked upon or altered by the TSP personnel in the absence of a representative from the Power Producer.

PART 4: OPERATION CODE

1. SECTION: PURPOSE AND SCOPE

1.1. OBJECTIVE

1.1.1. The general objective of this part of the Code is to specify the required System Operator and Users actions in order to ensure that the Power System in Nigeria is operated in a way to maintain adequate and safe transportation of Energy, plus System security at all times.

1.1.2. This adequate and secure operation is achieved through:

- (a) Adequate and economic ancillary services:
 - (i) Frequency Control and Operating Reserve (Section 3)
 - (ii) Voltage Control (Section 4)
 - (iii) Black Start Capability (Section 5)
- (b) Outline the general restoration strategy, adopted by the System Operator in the event of a Partial or Total Shutdown (Section 6)
- (c) Specifying procedures for operational planning in the short to medium term (Section 7)
- (d) Provision of information regarding risks or events in the Transmission System (Section 8)
- (e) Determining the actions that the System Operator shall undertake to perform the economic dispatch , and to provide Generators with running orders for the Dispatch Day. (Section 9)
- (f) Defining the requirements for notification of Generation Outages to the System Operator (Section 10).
- (g) Defining the reliability criteria the System Operator and the TSP have adhere to in operating and developing the Transmission System (Section 11).
- (h) Establishing central co-ordination and control of operational tests required by the System Operator, TSP or Users (Section 12)
- (i) Setting safety procedures for works to be carried out in the Transmission Network (Section 13)

1.2. SCOPE

1.2.1. The Operation Code applies to the System Operator, TSP and to Users of the Transmission System which in this Connection Conditions are:

- (a) Power Stations;
- (b) Distributors;
- (c) Interconnected Parties;

- (d) Customers connected to the Transmission System.

SECTION: POWER SYSTEM CONTROL

1.3. OBJECTIVE

1.3.1. The objective of this section is to specify the required System Operator and Users actions in order to ensure that the Power System in Nigeria is operated in a way to maintain adequate and safe transportation of Energy, plus System security at all times.

1.4. GENERAL

1.4.1. The System Operator shall carries out Network Planning, Development, Switching and Control Actions, which may from time to time affect Users operations or the security of supply to Users.

- (a) Network Planning is required for technical and design criteria and procedures to be applied by the System Operator for adequate and secure development of the Transmission Network for the benefit of all Users from time to time.
- (b) Network switching is required to implement the Transmission Outage scheduling program, routine operation of the Transmission Network and in responding to emergency and fault situations on the Transmission Network.

Additionally, network switching may occur automatically and without advance warning due to operation of protection equipment in isolating or clearing faults on Transmission Plant or on Participant's plant that is connected to the Transmission System.

1.4.2. All network Control Actions carried out on the Transmission System have the potential to affect Users. To attempt to inform Users of every Control Action is not practicable and in most cases the information will not be of value to the Participant, as the Participant will not invoke any specific action as a result of receipt of the information.

It may not always be possible for the System Operator to inform Users in advance of the switching or other Control Actions. This would be the case when the System Operator need to carry out urgent switching or other network Control Actions resulting from a Power System condition or fault. The System Operator shall endeavour to inform Users where time permits, but this shall not delay timely implementation of Control Actions as required.

In the event of a Power System fault or protection operation or other automatic operation, it will not be possible for the System Operator to invoke standing procedures prior to the occurrence of the Control Action.

1.5. POWER SYSTEM CONTROL ACTIONS

1.5.1. The System Operator shall be responsible to operate the Power System in such a way in order to maintain System security, achieve highest degree of reliability practicable and take

appropriate remedial action promptly to relieve any abnormal condition that may lead to dangerous operation at all times.

Consultation

System Operator shall consult with Users and take into consideration Users' reasonable requirements in controlling and development of the Transmission System.

Network switching

The System Operator shall carry out operational network switching for a number of purposes, which shall include:

- (a) Outages of Transmission Plant for the purposes of maintenance, new works, System Tests, protection testing and work by Users;
- (b) Outages of Transmission Plant due to suspected or potential faults and emergency repairs;
- (c) Voltage Control; and
- (d) Limiting power flows on the Transmission System to levels consistent with the capabilities of the Transmission Plant and System security.

1.5.2. Identification of Control Actions

The System Operator shall identify the Control Actions that may be needed to carry out maintenance and operation of the Transmission System and respond to Transmission System faults and emergencies

1.5.3. Automatic switching sequences

The System Operator shall establish automatic switching sequences to limit power flows or voltage dip or Frequency deviations in the event of faults on the Power System.

1.6. NOTIFICATION TO ALL USERS

1.6.1. The System Operator shall notify Users of the Transmission Network of a Control Action (if planned and where time permits), in accordance with the Grid Connection Agreement.

1.7. CONTROL UNDER FAULT OR EMERGENCY CONDITIONS

1.7.1. Notification after action

In the event that the System Operator needs to implement Control Actions urgently and without informing Users, then unless the situation is of a temporary nature and has been rectified to normal, the System Operator shall inform Users of the occurrence of the actions.

Generating Companies shall promptly inform the tripping of a Generating Unit, with reasons, to the System Operator in accordance with the guidelines given in Section 8 of

the Operational Code and other the operational event/incident reporting procedures operating at the time. The System Operator shall keep a written log of all such tripping, including the reasons for the purpose of demonstrating the effect on system performance and identifying the need for remedial measures. The Generating Companies shall submit a detailed report of their Generating Unit tripping to the System Operator every month.

1.7.2. Duration of condition

The System Operator shall also inform Users as to the likely duration of the condition and shall update this prognosis as appropriate. Additionally, the System Operator shall inform Users when the condition has ended.

1.8. DE-ENERGISATION OF PLANT

1.8.1. The System Operator shall de-energise a generating unit if it identifies any of the following causes or causes otherwise detailed in the Grid Connection Agreement:

- (a) Risk to the safety of personnel;
- (b) Risk to the stability of the Power System;
- (c) Risk to the Power System or any Participant's plant;
- (d) Power System elements to become loaded beyond their emergency limits;
- (e) Voltage Fluctuations on the Power System outside the specified ranges;
- (f) Any behaviour outside normal Power Station System operating range;
- (g) Any material breach of a connection condition; and
- (h) Any action (or inaction) that places the System Operator in breach of any legal, statutory or regulatory obligation.

[Note: The detailed list of above causes could be left to the Grid Connection Agreement.]

1.9. OPERATING PROCEDURES INCLUDING FAULT REPORTING

1.9.1. Approach

- (a) System Operator shall develop and maintain operating procedures for the safe operation of the Transmission Network, and for assets connected to the Transmission Network. These operating procedures shall be adhered to by Users when operating equipment or apparatus on the Transmission Network or connected to the Transmission Network.
- (b) Each User shall be responsible for his own safety rules and procedures at least in compliance with the relevant safety legislation. Users shall ensure that these rules and procedures are compatible with System Operator procedures.
- (c) Users shall enter into operating agreements as defined in the Grid Connection Agreement with System Operator.

1.9.2. Fault reporting and analysis/incident investigation

- (a) Generator operators shall report loss of output, tripping and pole slipping of Units and change of status of Generating Unit Governing control to within 15 minutes of the event occurring.
- (b) In the event of a multiple unit trip, the relevant User (i.e. Unit) shall take the following action: Any unit trip.
 - (i) The User (Unit) shall submit a written report to the System Operator within one month for any unit trip that could in future cause a Unit trip, identifying the root causes of the incident and the corrective actions taken.
 - (ii) In addition provide a full report as per the Grid Code, and this shall be treated as a major incident.
- (c) Distribution Network Operators and end-use customers directly connected to the Transmission Network, shall report the loss of major loads (>10MW) to the System Operator within 15 minutes of the event occurring. Notification of reconnection of such loads shall similarly be given with at least 30 minutes advance notice.
- (d) Incidents on the network involving sabotage or suspected sabotage, as well as threats of sabotage, shall be reported to the System Operator.
- (e) The System Operator shall investigate any incident that materially affected the quality of the service to another User. These include interruptions of supply, disconnections, under or over voltage or frequency incidents, quality of supply contraventions, etc.
 - (i) a preliminary incident report shall be available after three working days and a final report within three months.
 - (ii) System Operator shall initiate and co-ordinate such an investigation, arrange for the writing of the report and involve all affected Users. All these Users shall make all relevant information available and participate where reasonably required.
 - (iii) System Operator shall make the report available to any requesting participant within the confidentiality constraints.
- (f) Any User shall have a right to request an independent audit of the report, at its own cost. If these audit findings disagree with the report, the User may follow the dispute resolution mechanism. If the audit agrees with the report, the report recommendations shall stand.
- (g) All other recommendations shall be implemented by the User within the time frames specified

2. SECTION: FREQUENCY CONTROL AND OPERATING RESERVE

OBJECTIVE

2.1.1. The objectives of this section are:

- (a) To specify the System Operator requirements to ensure that adequate Frequency Control capability is provided on the Transmission System to enable operational Frequency Control by the System Operator, so as to achieve the applicable limits, and
- (b) To specify the Operating Reserve and Reliability Must-run requirements the System Operator has to adhere to in order to achieve the mentioned Frequency Control and adequate system reliability.

2.2. GENERAL

2.2.1. In order to maintain the security and integrity of the Transmission System it is necessary that the System Operator operate the Transmission System and Dispatch it in such a manner in order to provide adequate Frequency Control so as to achieve operation within applicable Frequency limits at all times. Frequency Control can be obtained by using primary or secondary Frequency Control.

2.2.2. Depending on network condition, generators will be required to move to or from Frequency Sensitive mode in combinations agreed in the relevant Ancillary Services Agreement or instructed by the System Operator.

2.2.3. In order to achieve this Control, the System Operator shall operate the System with adequate Operating Reserve. Operating Reserve is additional Active Power output provided from Generation Plant, or a reduction in consumer Demand, which must be realisable in real-time operation to contain and correct any potential Transmission System Frequency deviation to an acceptable level.

Operating Reserve is required to secure capacity that will be available for reliable and secure balancing of supply and demand.

2.3. FREQUENCY LIMITS

2.3.1. The Frequency shall be scheduled at 50 Hz. The National Control Centre will endeavour to control the System Frequency within a narrow operating band of $\pm 0.5\%$ from 50 Hz, at least for 90 % of the time during Normal Conditions. Under System Stress the Frequency Control on the Power System will be exercised within the limits of 50 Hz $\pm 2.5\%$ (48.75 – 51.25 Hz).

2.4. FREQUENCY CONTROL

2.4.1. During Normal Conditions, Frequency Control will be exercised utilizing the Spinning Reserve (Primary and Secondary Reserve). Occasionally, also the Emergency Reserve will be used.

2.4.2. The Nigerian Power System requires minimum of **600 MW¹** of Spinning Reserve power to secure the network:

- (a) The System Operator shall distribute the required Spinning Reserve power among the contributing Generating Units.
- (b) The Generators shall be responsible for continuous secure maintenance of their primary Frequency Control equipment as instructed by the System Operator.

Shortfall: The System Operator shall evaluate the Frequency Control performance during the day of operation and identify any shortfall. The System Operator shall instruct a Generator(s) to perform Frequency Control to counteract the shortfall.

(c)

2.5. COMPONENTS OF OPERATING RESERVE

2.5.1. There are two types of Operating Reserve namely Quick Reserve and Slow Reserve.

2.5.2. **Quick Reserve** is the reserve that can respond within ten seconds and be fully active within 30 minutes of activation. This Reserve is used for second-by-second balancing of supply and demand, and to restore frequency to nominal values following a disturbance. Quick Reserve shall consist of Spinning Reserve and Emergency Reserve

- (a) **Spinning Reserve:** Spinning reserve is the additional output from synchronised Generating Unit, which must be realisable to respond to containing and restoring any frequency deviation to an acceptable level in the event of a loss of generation or a mismatch between generation output and demand. The Spinning Reserve from the Generating Unit must be capable of providing response in two distinct ways and time scales: Primary Reserve and Secondary Reserve.
 - (i) **Primary Reserve:** Primary Reserve is an automatic increase/decrease in Active Power output of a Generation Unit in response to a System frequency fall/rise, in accordance with the primary control capability and additional mechanisms for acquiring active power. This change in active power output must be in accordance with the technical characteristics and loading of the Generation Unit, without any time delays other than those necessarily inherent in the design of the Governor Control System.

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As the Transmission Network develops, the figure of 600MW will change and new figure to meet operating requirements determined.

- (ii) **Secondary Reserve:** Secondary reserve is the automatic response to frequency changes which is fully available by 30 seconds from the time of frequency change to take over from the Primary Reserve, and which is sustainable for a period of at least 30 minutes.
- (b) **Emergency Reserve:** Emergency Reserve is typically made up from contracted interruptible load, gas turbines and emergency generation. Emergency Reserve is a less frequently used reserve and is used when the Transmission Network is not in a normal condition and to return the Transmission Network to normal conditions while slower reserves are being activated. The Reserve can be used by the System Operator for supply and demand balancing, network stability and voltage constraints. This Reserve shall be activated, on request, within ten minutes and shall be sustainable for two hours.

2.5.3. **Slow Reserve:** Slow Reserve is the component of the Operating Reserve not connected to the Transmission System but capable of serving demand within a specified time. Slow Reserve is used to restore Quick Reserve when required. Slow Reserve shall consist of Hot Standby and Cold Reserve.

- (a) **Hot Standby:** Hot Standby is a condition of readiness in relation to any Generation Unit that is declared available, where it is ready to be synchronise and attain an instructed load within 30 minutes, and subsequently maintained such load continuously.
- (b) **Cold Standby:** Cold Standby is a condition of readiness in relation to any Generation Unit that is declared available, to start, synchronise and attain target loading within a pre-defined period of time, typically within up to 12 hours.
- (c)

2.6. OPERATING RESERVE POLICY

2.6.1. The System Operator shall, in consultation with the other Users, specify the Operating Reserve policies, including its allocation of the permissible mix of Spinning and Quick Reserve, and procedure for applying Operating Reserve in practice, and the limitations, if any, upon the amount of Interruptible Load which may be included. The System Operator shall submit the Operating Reserve policy to the NERC for approval.

2.6.2. In developing the Operating Reserve Policy, due consideration shall be taken of relevant factors, including, but not limited to the following:

- (a) The cost of providing Operating Reserve at any point in time;
- (b) The magnitude and number of the largest Generation in-feeds to the Transmission System at that time, including in-feeds over Interconnections and also over single Transmission feeders within the Transmission System;
- (c) Ambient weather conditions, insofar as they may affect (directly or indirectly) Generating Unit and/or Transmission System Reliability;
- (d) The predicted Frequency drop on loss of the largest in-feed as determined through simulation using a dynamic model of the Power System;
- (e) Constraints imposed by Agreements in place with externally interconnected parties;

- (f) Historical Availability and Reliability performance of individual Generating Units;
- (g) Notified risk to the Reliability of individual Generating Units; and
- (h) Demand Forecasting uncertainties.

2.6.3. Unless proved to be technically impossible, or the economic burden imposed on the dispatch cost excessive, the Operating Reserve Policy shall be developed under following premises:

- (a) **Primary Reserve:** It shall be ensured that enough primary reserve is available to maintain system frequency within acceptable limits, following a contingency such as a unit trip or a sudden surge in load, without any under-frequency load shedding.

The frequency shall stabilize above 49.00Hz following all credible single contingency loss. The largest single unit loss permissible is 220MW (classified as a major incident).

- (b) **Spinning Reserve:** It shall be ensured to keep the frequency above 48.75 Hz after credible multiple contingencies, considering adequate operation of the under-frequency load shedding scheme, currently being the loss of 660MW generation (typically loss of a major hydro station)
- (c) The minimum Operating Reserve shall be sufficient to cover 150% of the loss of the sent-out capacity of the largest Generating Unit in service at that time. If two Generating Units are connected to the Transmission Network via one common Generation transformer, the sum of the two Generating Units' sent-out capacity shall be used as the largest Generating Unit.
- (d) **Operating Reserve mix:** The mix of Operating Reserve shall be as follows:
 - (i) An amount of Spinning Reserve, responsive to AGC, which is sufficient to provide Normal Regulating Margin; plus
 - (ii) An additional amount of Operating Reserve sufficient to reduce Area Control Error to zero within 10 minutes following loss of generating capacity which would result from the most severe single contingency. Interruptible Load may be included in the Quick Reserve provided that it can be interrupted within 10 minutes and can remain off until replacement Generation can be made available;
 - (iii) At least 50% of these Operating Reserves shall be spinning and the other 50% shall be Quick Reserve;
- (e) Operating Reserve shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

2.6.4. The System Operator shall, in consultation with the other Users, review probable contingencies frequently to determine the adequacy of Operating Reserve Policy, maintain it permanently under review. On an annual basis, it shall submit to the NERC an amended version for approval, taking into consideration the previous year's Frequency recovery performance.

2.6.5. **Record keeping:** The System Operator shall keep records of significant alterations to the Operating Reserve policy.

2.7. AMOUNT OF OPERATING RESERVE

2.7.1. The System Operator shall be responsible to determine the amount of Operating Reserve required for each Dispatch Period of the Dispatch Day, to be carried at any time to ensure system security, according with the Operating Reserve Policy approved by the NERC.

2.7.2. The Operating Reserve shall consist of Quick Reserve (Spinning Reserve and Emergency Reserve), and Slow Reserve.

2.7.3. In order to adequately and efficiently determine the amount of Operating Reserve:

- (a) Generators shall keep the System Operator informed of the Availability of its Generating Units.
- (b) The System Operator shall keep proper records of the Availability of its transmission resources.
- (c) The System Operator shall have information, including weather forecasts and past Load patterns, available to predict the Transmission System's future Load.
- (d)

2.7.4. The System Operator shall operate the Transmission System to provide for a level of Operating Reserve sufficient to account for such factors as errors in forecasting, generation and Transmission Equipment unavailability, number and size of Generating Units, system Equipment Forced Outage rates, maintenance schedules and regulating requirements. The System Operator shall take appropriate steps to protect the Power System against the next contingency, following the loss of Generation resources or Load.

2.8. OPERATING RESERVE PROCUREMENT

2.8.1. Operating Reserve is an Ancillary Service. During the Pre-Transitional, and the Transitional Stages, this Ancillary Service shall be considered mandatory. During the Medium Term Stage, and in the Final Stage the System Operator shall contract for Operating Reserve to enable the System Operator to operate the Transmission System securely at all times.

Primary Reserve

2.8.2. **Governor Control System.** In order that adequate Frequency Control is maintained on the Transmission System at all times, Generators are required to provide the Primary Reserve specified by the System Operator, complying with the following requirements:

- (a) Generating Units, when Synchronised to the Transmission System, shall operate at all times under the control of a Governor Control System, unless

otherwise specified by the System Operator, with characteristics within the appropriate ranges as specified in connection conditions;

- (b) No time delays other than those necessarily inherent in the design of the Governor Control System shall be introduced;
- (c) No Frequency dead bands shall be applied to the operation of Governor Control Systems.

Restriction of governor action: The Generator shall only restrict governor action where:

- (d) the action is essential for the safety of personnel and/or to avoid damage to plant; or
- (e) in order to secure the Reliability of the Generating Unit; or
- (f) the restriction has been agreed upon between the System Operator and the Generator in advance; or
- (g) the restriction is in accordance with a Dispatch Instruction given by the System Operator. The System Operator shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction.

Other types of Operational Reserve

2.8.3. During the Pre-transitional and Transitional Stages:

- (a) Each Generation Plant shall inform the System Operator its normal technical capabilities to provide different types of Operating Reserve, and the minimum time to make it operational.
- (b) Any Generation Plant shall not unreasonably refuse to provide Operating Reserve when it has the required technical capability and the System Operator assigns it in accordance with this Code.
- (c) When a Generation Plant identifies that, due to technical or operational problems or constraints, its capability to provide Operating Reserve has reduced compared to the normal capability informed to the System Operator, the it shall inform as soon as practical the System Operator of this constraint.

2.8.4. During the Medium Term and Final Stages:

- (a) The System Operator shall be responsible for contracting for the required Operating Reserve and shall Dispatch it economically between all the participating Generators, Distributors and Eligible Customers (in the case of Interruptible Load).
- (b) The System Operator shall agree on an annual basis with the Generators all the conditions relating to Frequency Control (Secondary Reserve). This shall include the possible range that each participating Generating unit can comply to and the time of the year when it shall be possible technically. The System Operator shall decide on the scheduling of the different Generating Units to perform Frequency Control. The System Operator shall base this on an

economic evaluation and Availability of the Generating Units. The System Operator shall instruct the Generating Units one day before they will be required to perform Frequency Control. The Generator shall be informed of the time interval and the range required.

- (c) Generators capable to operate in the regulating mode shall have priority in being contracted to carry Frequency Control.
- (d) Generators that are contracted for Secondary Reserve are required to respond with at least contracted capacity for low frequencies or according to the agreed droop characteristic. The response is required fully within thirty (30) seconds, to an increase or decrease in system frequency above/below the allowable dead-band. This response must be sustained for at least thirty (30) minutes.
- (e) When the System Operator decides to implement frequency regulation under AGC control, following rules shall apply:
 - (i) The AGC shall act as a secondary Frequency Control device and shall raise or lower the Generating Unit output according to an economic analysis of the participating Generating Units. This economic analysis takes the registered operating characteristics of Generating Units, Generator Nominations, Transmission System losses and Availability of plant into account to determine optimal Generating Unit output.
 - (ii) The System Operator shall ensure the balance between Generation and the Load. The System Operator shall achieve this by the deployment of secondary Frequency Control (AGC);
 - (iii) The secondary Frequency Control (Spinning Reserve) shall be contracted to Generators that have installed the required technical means for this purpose in conjunction with the System Operator
 - (iv) On the basis of an annual Dispatch Schedule, the System Operator and the corresponding Generators shall agree Bilateral Agreements for operation under secondary Frequency Control (providing of Secondary Reserve);
 - (v) Based upon these conditions and the Dispatch Schedule, the System Operator shall decide which Generators to involve in secondary Frequency Control (providing Secondary Reserve) and at what time intervals, in accordance with the principle of minimum costs and Availability;
 - (vi) The AGC shall be managed via the SCADA system at the National Control Centre.
 - (vii) **Reliability Must-Run Requirements:** The System Operator shall contract Reliability Must-run Generating Units to cater for situations where Emergency Reserve power is needed to keep the Transmission System secure.

The System Operator shall determine the needed Reliability Must-run requirements by performing extensive Reliability studies on the Transmission System, taking the scheduled Outages into account.

The System Operator shall quantify the risk the Transmission System is exposed to due to unanticipated Outages. Based on this risk assessment, additional Reliability Must-run Agreements might be needed.

The System Operator shall report on all Reliability Must-run Agreements by including the details in the Reliability annual assessment report on an annual basis to the NERC. This report shall address the reasoning for each Reliability Must-run Agreement and the achieved performance of each Reliability Must-run Unit.

3. SECTION: VOLTAGE CONTROL

3.1. OBJECTIVE

3.1.1. The objective for Voltage Control is to achieve a healthy voltage profile for the Power System.

3.2. GENERAL

3.2.1. The System Operator shall endeavor to maintain sufficient Availability of dynamic and static Reactive Power in order to maintain the Transmission System voltages at Connection Points within the levels specified, at all times.

3.2.2. The System Operator should use the effects of Transmission System capacitance in controlling the Transmission System voltage.

3.2.3. The System Operator can operate the Transmission System voltage towards the upper portion of the allowable control range at times of high Reactive Power Demand (normally times of high Active Power Demand).

3.2.4. The System Operator can operate the Transmission System voltage towards the lower portion of the allowable control range at times of low Reactive Power Demand (normally times of low Active Power Demand).

VOLTAGE CONTROL

Responsibility: The System Operator shall be responsible for:

- (a) maintaining voltage stability of the Transmission System; and
- (b) maintaining Transmission System voltages at Participant Connection Points within operational limits.

3.2.5. **Dispatch:** The System Operator shall, by means of Dispatch Instructions, instruct Generators to adjust the voltage level at the Connection Point or the Reactive Power output of Generating Units.

Control facilities: The System Operator shall adjust Transmission System voltages, using available control facilities. This is to achieve the Reactive Power capacity necessary in order to maintain Transmission System voltages at Connection Points within the specified levels.

3.2.6. The remedies or penalties regarding non-compliance with regards to Voltage Control must be detailed in the Grid Connection Agreement.

3.3. VOLTAGE CONTROL POLICY

3.3.1. Transmission System losses: The System Operator shall control system voltages in order to maximize the reliability of the Transmission System, trying, when possible, to minimise Transmission System losses and the cost of the Ancillary Services.

3.3.2. **Procedures:** The System Operator shall determine and modify, as appropriate, general procedures for controlling voltages on the Transmission System. The procedures shall be formulated considering the relevant economics of Transmission System operation and Power System Reliability. In determining these procedures, the System Operator shall consider daily, weekly and seasonal factors. The System Operator shall determine:

- (a) suitable target voltages in order to limit/control the effect of Transmission Capacitance;
- (b) best utilisation of dedicated Voltage Control facilities; and
- (c) Reactive Power dynamic reserve requirements.

3.4. VOLTAGE CONTROL METHODS

3.4.1. The System Operator shall use the following Voltage Control methods:

- (a) Transformer tap-changing, cable switching, reactor and capacitor switching, and other control methods which involve utilisation of Transmission System plant only;
- (b) Tap-changing on Generator transformers;
- (c) Demand power factor correction;
- (d) Utilisation of Generating Unit Reactive Power capability, both by means of AVR control and also Reactive Power Dispatch Instructions issued by the System Operator to Generators; or
- (e) Eventually, and only if Reliability of the Transmission System is not heavily affected, the switching of Transmission Lines in order to reduce the capacitive contribution of the Transmission System.

3.4.2. **Monitoring:** The System Operator shall monitor the Transmission System Voltages continuously. Appropriate voltage operating points shall be determined by the System Operator, taking account of the Voltage Control policy and in particular of system conditions pertaining at the time of operation.

3.5. VOLTAGE CONTROL DURING EMERGENCIES

3.5.1. The System Operator shall utilise additional Voltage Control mechanisms in the event of System Emergency Conditions. These shall include the following:

- (a) Generators may be requested to operate Generating Units at Reactive Power levels (delivering or absorbing) outside their currently registered operating characteristics. This will be done by agreement between the Generators and the

System Operator and Generators will not be penalised for non-compliance with this Condition;

- (b) System wide restoration of voltages by instructing Generators to carry out a tap-change on the main Generator transformer of several Generating Units simultaneously; and
- (c) Load shedding may be used to prevent Voltage from contravening Low Voltage limits at Connection Points.

3.6. PROVISION OF VOLTAGE CONTROL

3.6.1. Voltage Control is an Ancillary Service. Minimum requirements for this Ancillary Service, that all Participants are obliged to provide are established in this Code. During the Medium Term Stage, and in the Final Stage the System Operator may establish contract for additional enhanced Voltage Control with some Participants in order to enable the Transmission System be operated efficiently and securely at all times.

3.6.2. During the Pre-transitional and Transitional Stages:

- (a) Each Generating Unit shall inform the System Operator its Capability Curve. In case there exists seasonal or permanent technical restrictions, that could prevent the Generating Unit to produce reactive power within the limits of this curve, this situation shall be reported to the System Operator.
- (b) The Generating Unit shall normally be operated under the control of a continuously acting AVR, which shall be set so as to maintain a constant terminal voltage within the voltage range specified by the System Operator. While the reactive power produced by the Generation Unit is within the limits indicated in the Capability Curve, the Generator may only disable or restrict AVR action:
 - (i) where the action is essential for the safety of personnel and/or plant;
 - (ii) in order to secure the Reliability of the Generating Unit; or
 - (iii) where the restriction has been agreed upon between System Operator and the Generator in advance.
- (c) When a Generation Plant identifies that, due to technical or operational problems or constraints, its capability to provide reactive power has reduced compared to the normal capability informed to the System Operator, the it shall inform as soon as practical the System Operator of this constraint.
- (d) **Generating Unit restrictions:** The System Operator may impose restrictions on the operation of the Generating Unit in accordance with Good Utility Practice in the event of a Generating Unit not operating under AVR. This shall provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-energise the Generating Unit.

3.6.3. During the Medium Term and Final Stages:

- (a) Minimum Requirements for Generating Units

- (i) The minimum amount of reactive power each Generating Unit shall be able to produce, if required by the System Operator, is defined by the following limits:

- a.i.1) Inductive: 25 % of the rated active power ($\cos \phi = 0,97$ at full output)
 a.i.2) Capacitive: 15 % of the rated active power ($\cos \phi = 0,989$ at full output)

The Generating Unit shall be able to deliver this reactive power within the whole range of generated active power (from technical minimum to rated capacity)

- (ii) Each Generating Unit shall normally be operated under the control of a continuously acting AVR, which shall be set so as to maintain a constant terminal voltage within the voltage range specified by the System Operator. The Generator shall not disable or restrict the operation of the AVR except for the conditions identified below, in which event the Generator shall notify the System Operator without delay.
- (iii) **AVR restriction:** While the reactive power produced by the Generation Unit is within the limits indicated in Section 4 of the Connection Conditions the Generator may only disable or restrict AVR action-
- a.iii.1) where the action is essential for the safety of personnel and/or plant;
 a.iii.2) in order to secure the Reliability of the Generating Unit; or
 a.iii.3) where the restriction has been agreed upon between System Operator and the Generator in advance.
- (iv) **Generating Unit restrictions:** The System Operator may impose restrictions on the operation of the Generating Unit in accordance with Good Utility Practice in the event of a Generating Unit not operating under AVR. This shall provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-energise the Generating Unit. The System Operator shall consult with the Generator as soon as possible after such actions had been taken in order to determine a safe operating regime, which causes minimum restriction on the operation of the Generating Unit.
- (b) **Minimum Requirements for Distributors or Customers Connected to the Transmission System**
- (i) The Distributors and customers Connected to the Transmission System shall maintain an inductive Power Factor not less than 0.95 at the Connection Point, unless a different value have been agreed in the Connection Agreement.
- (c) **Additional requirements for Voltage Control**
- (i) In case the System Operator considers that additional means of Voltage Control are required in the Transmission System (in excess of those previously stated), it can procure them, establishing contracts with Generation Units, Distributors or Customers Connected to the Transmission System.

4. SECTION: BLACK START

4.1. OBJECTIVE

4.1.1. The objective of this section is to stipulate the Black Start requirements the System Operator has to cater for.

4.2. GENERAL

4.2.1. Generating Units have to be identified that can start on own resources from a total de-energised state which may be due to emergency condition declared by System Operator as in Section 6 of the Operational Code or Appendix 9 of this Code. Such Generating Units may be necessary to start other Generating Units and revive the Power System following a Total Shutdown. The necessary contracts must be closed between the System Operator and Generators to provide Black Start Capability and appropriate tests must be done on a regular basis to ensure that the Power System can be reactivated following such an extreme emergency situation.

4.3. ANCILLARY SERVICE

4.3.1. Black Start is an Ancillary Service. The System Operator shall contract for Black Start to enable it to operate the Transmission System securely at all times.

4.4. REQUIREMENTS

4.4.1. The System Operator shall set out the requirements for Black Start Stations to enable recovery of the Transmission System from a Partial Shutdown or Total Shutdown.

4.4.2. Requirements for Black Start Stations:

- (a) Black Start Stations shall have the ability for at least one of its Generating Units to start-up from shutdown and to energise a part of the total system, or be Synchronised to the System.
- (b) The Black Start Stations shall perform Black Start upon instruction from the System Operator, without an external electrical power supply.
- (c) The Black Start Power Station shall inform the System Operator if during the Demand restoration process any Black Start unit cannot, because of the Demand being experienced, keep within its safe operating parameters.
- (d) The System Operator shall where possible, either instruct Demand to be altered or will re-configure the Transmission System or will instruct a Participant to re-configure its system in order to alleviate the problem being experienced by the Generator.

- (e) However, System Operator will accepts a suitable decision to keep a Generating Unit in a Power Station operate outside its safe operating parameters, for a limited period of time. The System Operator shall accept that the Generator operator may change Generation on that unit if it believes it is necessary for safety reasons. The Generator shall inform the System Operator as soon as reasonably practical if such a change is made without prior notice.

5. SECTION: EMERGENCY OPERATION AND RESTORATION

5.1. OBJECTIVE

5.1.1. The objective of this section is to outline the general restoration strategy, which shall be adopted by the System Operator in the event of a Partial or Total Shutdown of the Transmission System emergency condition or that indicated in Appendix 8. This includes the need for a restoration plan and an under Frequency Load shedding scheme.

5.2. GENERAL

5.2.1. The Operating States of a Power System are classified into five Operating States, namely normal, alert, emergency, in extreme and restorative.

5.2.2. The different Operating States can be defined as follows:

(a) Normal Operating State

The Power System variables, voltage and lines, are within the normal range and no equipment is being overloaded. The Power System operates in a secure manner and can withstand any single contingency without violating any of the limits.

The Power System should be in this mode of operation for most of the time. The System Operator shall endeavour to operate the Power System such that it is in the normal Operating State.

(b) Alert Operating State

The Power System will move into this state of operation once the security level falls below a certain limit. This could also be due to the possibility of a disturbance due to bad weather conditions, such as a severe storm.

The Power System variables, voltage and lines, are within acceptable operating range and limits. However, the Power System is weakened and the next contingency could cause an overload or voltage violation. Emergency operating state

The Power System will move into this state of operation if a severe disturbance occurs or under a civil emergency situation as in Appendix 8, when the system is in the alert operating state. Some of the busbar voltages will be low and/or equipment will exceed its short-term emergency ratings. The system will still be intact and can return to the alert Operating State once the emergency actions have been initiated, such as fault clearing, excitation control, generating tripping and Load curtailment.

(c) Extreme Operating State

The Power System will move into this state of operation once the emergency actions have failed to be effective. This will result in a possible cascade tripping of the transmission lines and Generators and a possible Shutdown of a part of the Power System. The Power System can then be saved by the initiation of under Frequency Load shedding and controlled separation of portions of the Power System.

(d) Restorative Operating State

The System Operator shall reconnect all the facilities and restore the system Load during this Operating State either through approach in Section 5 or other safe method deemed necessary by System Operator. The Operating State of the Power System will then move from Operating State to restorative state until it has once again reached again the normal Operating State.

5.3. EMERGENCY OPERATION

5.3.1. Operating states

System Operator shall always be in a position to determine the Operating State of the Power System. The System Operator shall be responsible to inform all the parties involved once the Operating State changes from one Operating State to another.

5.3.2. System Operator shall develop and maintain contingency plans to manage system contingencies and emergencies that are relevant to the performance of the Transmission Network. Such contingency plans shall be developed in consultation with all Users, which shall be consistent with the actual situation of the Nigerian Power System and internationally utility best practices. It shall include but not be limited to:

- (a) under-frequency load shedding
- (b) meeting system disaster management requirements including the necessary minimum
- (c) load requirements
- (d) forced Outages at all points of interface, and
- (e) supply restoration.

5.3.3. Emergency plans shall allow for quick and orderly recovery from a partial or complete system collapse, with least cost solution and minimum impact on customers.

5.3.4. The System Operator shall periodically verify contingency and/or emergency plans by actual tests to the greatest practical extent possible. In the event of such tests causing undue risk or undue cost to a User, the System Operator shall take such risks or costs into consideration when deciding whether to conduct the tests. Any tests shall be carried out at a time that is least disruptive to the User and embedded End-use Customers. The costs of these tests shall be borne by the respective asset owners. The System Operator shall ensure the co-ordination of the tests in consultation with all affected Users.

5.3.5. The System Operator shall specify minimum emergency requirements for Distribution Control Centres, power station local control centres and substations to ensure continuous operation of their control, recording and communication facilities.

Other Users shall comply with the System Operator reasonable requirements for contingency and emergency plans.

5.3.6. The System Operator shall set the requirements for automatic and manual load shedding. Users shall make available loads and schemes to comply with these requirements.

5.3.7. The System Operator, in consultation with the TSP, shall be responsible for determining all operational limits on the Transmission Network, updating these periodically and making these available to the Users.

5.3.8. The System Operator shall conduct load flow studies regularly (at least monthly) to determine the effect that various component failures would have on the reliability of the Transmission Network. At the request of the System Operator, Distribution Network Operators shall perform related load flow studies on their part of the network and make the results available to the System Operator.

5.3.9. Procedures and facilities

System Operator shall ensure that the necessary procedures and facilities are in place to support quick and secure re-establishment of the Shutdown parts and restore supply to Users.

5.3.10. Safety

The System Operator shall de-energising certain plant in order to provide for safe and secure operation of the Transmission System within prescribed standards, including-

- (a) During a System Emergency Condition;
- (b) During Power System restoration; and
- (c) Following the issue of an In-extreme operating state.

5.4. RESTORATION OF SUPPLY

5.4.1. Restoration plan

The System Operator shall develop and maintain a well-documented Power System restoration plan for the Nigerian Power System. The System Operator shall consult with all the stakeholders on an annual basis to review the restoration of supply in Nigeria. The Power System restoration plan shall include the restoration of the Power System from a Total Shutdown and shall also address a Partial Shutdown.

The System Operator shall inform all the Users of the procedure for Power System restoration at the time of a partial or Total Shutdown. Each Participant shall abide by the System Operator's instructions during the restoration process, subject to the safety of personnel and the Users' plant.

5.4.2. Training

The System Operator shall be responsible for the training of all personnel who may be involved in Power System restoration. They must be familiar with, and adequately trained and experienced in their standing instructions and other obligations so as to be able to implement the procedures and comply with any procedures notified by the System Operator.

5.4.3. In-extreme Operating State test

The System Operator shall, in consultation with all stakeholders, issue an In-extreme Operating State at least once each year. This will be a test and not a real situation. The purpose of this would be to ensure proper training of all personnel involved. The stakeholders shall be notified in advance of the content of the tests and a date and time for execution of the tests shall be agreed. The stakeholders must, acting in accordance with Good Utility Practice, co-operate with any such testing.

5.5. BACK-UP CONTROL CENTRE

5.5.1. Plan

The System Operator shall have a plan to continue its operations in the case of the National Control Centre becoming inoperable. This plan could include a permanent back-up Control Centre shadowing the main National Control Centre with the appropriate trained staff on site. In this case the back-up Control Centre shall be located remote from the site of the National Control Centre.

5.5.2. Training

The System Operator shall also ensure that the staff members of the back-up Control Centre have been well informed and well trained to enable them to operate the Power System securely. This site shall also be equipped with the required telecommunication infrastructure capable to transfer all relevant data and the required voice communications needed to operate the Power System.

5.6. EMERGENCY CO-ORDINATION FACILITY

5.6.1. The System Operator shall make provision for an emergency co-ordination facility as part of the restoration plan.

5.6.2. The emergency co-ordination facility shall mean a site, remote from the National Control Centre, providing at least the minimum level of communication capabilities necessary for operation of the Power System. The emergency co-ordination facility shall be utilised in the event that an emergency situation or major failure of facilities at the NCC (and/or back-up Control Centre if applicable) prevents operation from either the NCC or the back-up Control Centre.

5.6.3. In the event of the emergency co-ordination facility being utilised, the System Operator shall be able to communicate with the following stakeholders during such an emergency:

- (a) All Users;
- (b) The Commission;
- (c) The Federal Government; and
- (d) The Defence force.

5.6.4. The System Operator shall ensure that the emergency co-ordination facility is equipped with up to date single line diagrams, operating diagrams and operating procedures at least once a year.

5.6.5. The back-up Control Centre could be used as emergency co-ordination facility.

5.7. UNDER FREQUENCY LOAD SHEDDING

5.7.1. Policy and analysis

The under Frequency Load shedding shall be the last step during an emergency. All other remedial steps should have been taken already.

The under Frequency Load shedding scheme shall be studied by the Operational Planning staff on an annual basis and it shall be the responsibility of the TSP to implement any modifications.

Under Frequency Load shedding shall be in steps related to one or more of the following: Frequency, rate of Frequency decay, voltage level, rate of voltage decay or power flow.

The System Operator shall be responsible to compile a proper under Frequency Load shedding scheme policy. This policy shall be revised on an annual basis. As initial policy five under Frequency Load shedding steps can be recommended. However, this needs to be studied in detail by the Operational Planning staff. These five steps are:

- (a) 10 % of the maximum Demand at 49.2 Hz with a 0.3 second delay;
- (b) 10 % of the maximum Demand at 49.0 Hz with a 0.3 second delay;
- (c) 10 % of the maximum Demand at 48.8 Hz with a 2 second delay;
- (d) 10 % of the maximum Demand at 48.5 Hz with a 2 second delay; and
- (e) 10 % of the maximum Demand at 48.2 Hz with a 2 second delay.

[Note: The above-mentioned steps are an example only. The specific conditions in Nigeria need to be studied in order to develop suitable steps for the Nigerian Power System].

5.7.2. Under Frequency Load shedding scheme

The System Operator shall ensure that the Power System is equipped with a well co-ordinated under Frequency Load shedding scheme.

The under Frequency Load shedding scheme shall automatically be activated by the relays for insufficient Generation or Transmission Capacity to safeguard the Power System.

The System Operator shall ensure that the under Frequency Load shedding relays are located on dedicated Loads or distribution/ reticulation transformers and not random feeders.

5.7.3. Co-ordination

Under Frequency Load shedding shall be co-ordinated throughout the Power System with other under Frequency isolation, such as Generator tripping or isolation, shunt capacitor tripping, and other automatic actions which occur during abnormal Frequency or voltage conditions.

5.7.4. Testing

Under Frequency Load shedding relays shall be tested in six-monthly intervals to ensure that they are still connected and in good working order.

5.7.5. Manual Load shedding

Should the under Frequency Load shedding not be sufficient, the System Operator shall shed Load manually if the System can still be saved from a Total Shutdown.

5.7.6. Re-Synchronisation

The System Operator shall shed additional Load manually before re-Synchronising the different islands after the Power System separates into various islands and there is insufficient generating capacity in the islands to restore the Power System Frequency following under Frequency Load shedding.

6. SECTION: OPERATIONAL PLANNING

6.1. OBJECTIVE

6.1.1. The objective of Operational Planning is to specify technical, design, information exchange and procedures to be applied by the System Operator to proper operation of the Transmission System in the short to medium term. These also include studying and documentation of short and medium-term events. It shall ensure that the System Operator is prepared for short to medium term situation and emergency. This section describe the different technical activities necessary to ensure that Users and System Operator are well informed of the status of the System during maintenance and unforced Outage conditions.

6.2. GENERAL

6.2.1. The following activities shall be performed by the System Operator to enable it plan for a stable Power System at all times:

- (a) Create data base for:
 - (i) Steady state;
 - (ii) Sequence data; and
 - (iii) Dynamic data.
- (b) Compile a representative model:
 - (i) Peak/minimum loading for present year; and
 - (ii) Peak/minimum loading for the next five years.
- (c) Perform load flow studies for all cases involved, checking the power flow and the voltage profile for the existing network;
- (d) Calculate fault levels at all substations on an annual basis;
- (e) Use the daily Demand Forecast to conduct n-1 / n-2 contingency studies to prepare for the next operational day, or any other situation in the near future. All the maintenance plans shall be studied to see the feasibility of that Outage in the next day or near future. This shall prepare the National Control Centre for any unexpected conditions that could occur. It is important considering any maintenance on major transmission lines that could be planned for the next day;
- (f) Conduct contingency studies for the year ahead up to 3 years in advance and prepare a strategy of how to achieve the Reliability indices pursuant to section 10.2.3;
- (g) The results of the contingency studies shall be documented in a contingency plan. This plan shall be needed when the remaining lines overload or have severe voltage depressions. The contingency plan shall be studied to arrive at a viable operational solution. The aim shall be to maintain contingency of supply to the Users;
- (h) As part of the contingency plan the thermal rating of all the links should be determined for the involved Users substations. It should include the

transformer rating and breaker breaking capacity. It is important to have information of both the 75°C and 90°C thermal limits of all the power equipment involved;

- (i) The results shall be in the form of a single line Load flow diagram, and the contingency plan shall consist of the single line diagram and detail switching instructions and precautions that should be taken prior to any operational activity;
- (j) The dynamic data shall be used to perform some studies related to the voltage collapses that could occur during certain contingencies. It shall also be used to see the dynamic behaviour of the system during certain major contingencies. It can also be used to check the optimum ARC dead time for the Distribution System. Some of these times can be optimised and subsequently lead to the improvement of the Quality of Supply to the Distribution consumers;
- (k) Voltage collapse studies should also be performed using steady-state data. This shall be necessary to determine the maximum transfer across a certain network to Users. These studies shall indicate at what stage more expansion would be needed given the rate of consumer Load growth in a particular area;
- (l) The System Operator's Operational Planning staff shall ensure that the above documentation is in the control room and that these documents are always updated to the latest expansion in the Power System; and
- (m) System Operator's Operational Planning staff shall study the implementation of under Frequency Load shedding scheme. These studies shall be updated on an annual basis and the new settings and requirements shall be given to the System Operator to implement as soon as possible.
- (n) The System Operator shall perform studies to determine the level of reinforcement or expansion required of the Transmission Network to meet new operating conditions and User(s) requirements, including those arising from a new User connection.

6.3. FUNCTIONS OF THE OPERATIONAL PLANNING STAFF

6.3.1. The Operational Planning staff of the System Operator shall perform the following functions.

- (a) Development of plan

The System Operator shall develop a set of operational plans, which are designed to evaluate options and documented procedures for reliable operation.

- (b) Plan maintenance

The System Operator shall maintain a set of operational plans, which are designed to evaluate options and documented procedures for reliable operation.

- (c) Plan implementation

The System Operator shall utilise the appropriate staff to implement operational plans and to assure that the System is operated reliably and securely.

- (d) Information and training

The System Operator shall also ensure that the National Control Centre and the relevant Control Centre staff are well informed and trained to use this information.

- (e) Reviews

The Operational Planning staff of the System Operator shall be responsible for reviewing the under Frequency Load shedding scheme, as defined in Condition 6.7.2 on an annual basis.

6.3.2. The Operational Planning staff shall be experienced in the operation and planning of a Power System. The required areas of expertise are the following:

- (a) Technical Operational Studies
 - (i) Load flows;
 - (ii) Contingency studies;
 - (iii) Dynamic studies (Power System stability);
 - (iv) Voltage collapse;
 - (v) Expansion studies; and
 - (vi) Energisation studies.
- (b) Operational -Documentation
 - (i) System operation guidelines;
 - (ii) System operation procedures; and
 - (iii) Database creation, storage and achieving.
- (c) Emergency operation and Power System restoration

The System Operator Operational Planning staff will have major inputs into the restoration plans of the System Operator as defined in Condition 6.4.

6.4. DATA REQUIRED FOR MEDIUM TERM AND OPERATIONAL PLANNING

6.4.1. By week 32 of each Calendar year, each User shall provide the System Operator with the data requested below (except Demand solely related to Power Station Auxiliary plant when fed in accordance with pre-agreed feeding arrangements), for current Calendar year and each succeeding three Calendar years.

6.4.2. Profiles

Power Stations, Distribution Network Operators and Customers Connected to the Transmission System shall supply the following information in writing to the System Operator a year in advance:

- (a) Typical daily profiles of the anticipated Demand per Connection Point during each Dispatch Period over a week.

- (b) Typical daily maximum Demand values of the anticipated Demand per Connection Point over a month;
- (c) Typical monthly maximum Demand values of the anticipated Demand per Connection Point over a year;

6.4.3. Generating Units

Power stations, Distribution Network Operators and Customers Connected to the Transmission System shall supply typical Active and Reactive Power profiles for their operation, and Availability as appropriate, of Generating Units under their control and those not participating in the System Operator Administered Market where the total registered capacity of Generating Units on a single site exceeds **10 MW**. The method for submitting these data schedules for such Generating Units shall be the same as provided for in the Market Rules or other Agreements for Generators participating in the System Operator Administered Market.

6.4.4. On the last business day of every calendar week, Users shall provide the System Operator with the data requested below (except Demand solely related to Power Station Auxiliary plant when fed in accordance with pre-agreed feeding arrangements), for the following 14 days after the submission.

6.4.5. Day-ahead Demand and Availability Forecast

- (a) Demand Forecasts factors

The System Operator shall take the following factors into account when conducting Day-ahead Demand Forecasting:

- (i) Historical Demand data;
 - (ii) Weather forecasts and the current and historical weather conditions;
 - (iii) The incidence of major national and local events or activities that are known to the System Operator in advance;
 - (iv) Transmission System losses;
 - (v) Generating Units not participating in the market;
 - (vi) Demand Control of **1 MW** or more (averaged over any half hour at any Connection Point) proposed to be exercised by any Distributor and of which the System Operator has been informed;
 - (vii) Other information supplied by Users; and
 - (viii) Interconnection transfers.
- (b) Demand Forecast methodology

System Operator shall use a Demand Forecast methodology based on factors in 10.4.5 (a) to produce, by statistical means, unbiased forecasts of Demand including that to be met by Distribution Embedded Units. Demand shall be calculated from these forecasts, but shall also take into account factors (e), (f), (g) and (h) in Condition 10.2.

- (c) Demand Profiles

Power Stations, Distribution Network Operators and Customers Connected to the Transmission System shall supply the following information in writing to the System Operator 14 days in advance:

- (i) Typical daily profiles of the aggregated Demand on their system during each Dispatch Period.
- (ii) Typical daily maximum Demand values of the anticipated Demand per Connection Point over a 14 day period;
- (iii) Typical weekly maximum Demand values of the anticipated Demand per Connection Point over a 14 day period;
- (d) Demand Control

Distribution Network Operators and Customers Connected to the Transmission System shall supply Active and Reactive Power demand profiles by 8:00 hours on the Pre-Dispatch Day of the amount and duration of anticipated Demand Control per Connection Point that may result in a Demand change of 1 MW or more during each Dispatch Period of the Dispatch Day.

- (e) Generating Units

Power stations, Distribution Network Operators and Customers Connected to the Transmission System shall supply typical Active and Reactive Power profiles for their operation, and Availability as appropriate, of Generating Units under their control and those not participating in the System Operator Administered Market where the total registered capacity of Generating Units on a single site exceeds 1 MW. The method for submitting these data schedules for such Generating Units shall be the same as provided for in the Market Rules or other Agreements for Generators participating in the System Operator Administered Market.

6.5. ACTUAL DEMAND CONTROL DATA

6.5.1. The Distribution Network Operators and Customers Connected to the Transmission System shall supply the following in writing (or by such electronic data transmission facilities as have been agreed upon with the System Operator) to System Operator by 14:00hr each day:

- (a) Active Power profiles per Connection Point for the previous Dispatch Day of the amount and duration of Demand reduction achieved from the use of Demand Control of 10 MW or more (averaged over Dispatch Periods on any Connection Point), for each Dispatch Period.
- (b) Distribution Network Operators and Customers Connected to the Transmission System shall notify System Operator of their intending Demand Control including customers demand management which may result in change of 10MW or more power on the Transmission Network.

6.6. CONNECTIONS

6.6.1. New connections

Power Station owners, Distribution Network Operators, Customers Connected to the Transmission System shall provide to the System Operator written information pertaining to new connections / additional Generation or Demand greater than 1 MW immediately when this information becomes available. This information shall include:

- (a) Anticipated connection date;
- (b) Location of connection;
- (c) Size of consumers category of connection (e.g. residential, industrial etc.); and
- (d) The typical profiles of the anticipated Generation or Demand on half hourly basis for defined categories of day type as determined by the System Operator;

6.6.2. Disconnection

Power Station owners, Distribution Network Operators, Customers Connected to the Transmission System shall provide to the System Operator written information pertaining to disconnection of existing Generation or Demand immediately and not more than 12 Calendar weeks when this information becomes available. This information shall include:

- (a) Anticipated disconnection date;
- (b) Location of connection;
- (c) Size of connection; and
- (d) The revised typical profiles of the anticipated Generation or Demand on a half hourly basis at the Connection Point for defined categories of day type as determined by the System Operator;

6.7. CHANGES TO INFORMATION ALREADY SUPPLIED

6.7.1. Changes

Power Stations, Distribution Network Operators and Customers Connected to the Transmission System shall inform the System Operator of any changes to the information already supplied as soon as this information is available. This information shall be provided in writing, or as otherwise agreed between Users of the Transmission Network and the System Operator, such Agreement not to be unreasonably withheld.

6.7.2. Monthly confirmation

The Purchasers shall confirm in writing on the 5th last business day of every month that the most recently submitted Active Power Demand profiles for the following two months are in accordance with their current best estimate of these values.

6.7.3. Weekly Confirmation

Users of the Transmission network shall confirm in writing on the last business day of every week that the most recently submitted data profiles for the following 14 days are in accordance with their current best estimate of these values.

6.8. TIMING AND PUBLICATION

6.8.1. The System Operator shall provide a day ahead Demand forecast for the Transmission System each Pre-dispatch Day by 11:00 for each Dispatch Period for the next Dispatch Day. This information shall be provided by being posted in the System Operator Website or other agreed medium and shall be in a format reasonably determined by the System Operator and Users as being suitable.

6.8.2. The Demand Forecast shall include Transmission System losses.

7. SECTION: INFORMATION EXCHANGE

7.1. OBJECTIVE

7.1.1. The objective of this section is to provide for the exchange of information so that the implications of an Operational error and/or Power System event can be considered. The possible risks must be assessed and appropriate action taken by the relevant party in order to assist in maintaining a secure Power System. The correct information needs to be identified and communicated to the correct structures in the Nigerian ESI.

7.2. GENERAL

7.2.1. This section sets out the requirements for the exchange of information in relation to Operations and/or events on the Power System, which have had or shall have an operational effect, and thereby have become Power System incidents:

- (a) On the Transmission System in the case of an operation and/or event occurring on a Distributor's system; and
- (b) On a Distributor's system in the case of an operation and/or event occurring on the Transmission System.

7.2.2. The System Operator shall report any Event or operation on the Transmission System to all Distributors and Generators. This notification is expected to report what shall happen or what has happened on the Power System.

7.2.3. The System Operator shall have information available for system incident analyses by means of:

- (a) The System Operator's SCADA system(s) and other data collection systems; and
- (b) Information provided to the System Operator by Users under other Conditions of this Code.

7.3. REQUIREMENT TO NOTIFY

7.3.1. The System Operator, Distributors and Generators shall agree to review from time to time which operations and events shall be required to be notified.

7.4. NOTIFICATION OF AN OPERATION

7.4.1. The System Operator shall establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the network under normal and abnormal conditions.

7.4.2. The System Operator shall notify all Distributors and Generators of any operations on the Transmission System, which shall have, in the reasonable opinion of the System Operator, an operational effect on any Participant.

7.4.3. The System Operator may proceed with urgent operations without notifying all Distributors and Generators and without the required procedures. This can only be done if it is of a temporary nature and less than 15 minutes. The System Operator shall notify all Distributors and Generators of any operations on the Transmission System without any delay as soon as the System has been restored to normal. The System Operator shall also inform the Distributors as to the likely duration of the condition and shall update this prognosis as appropriate. The System Operator shall additionally inform the Distributors as soon as reasonably possible when the condition has ended.

7.4.4. The Distributor shall notify the System Operator of operations on the Distributor's system, which shall have an operational effect on the Transmission System. The System Operator shall notify any other Distributors on whose system(s) the operation shall have an operational effect.

7.5. FORM OF NOTIFICATION OF AN OPERATION

7.5.1. A notification of an operation shall be of sufficient detail to describe the operation and to enable the recipient of the notification to reasonably consider and assess the implications and risks arising.

7.5.2. A notification shall include the name of the individual reporting the operation on behalf of the System Operator or the Distributor, as the case may be.

7.5.3. The recipient of the notification may ask questions to clarify the notification and the System Operator or the Distribution Network Operators shall answer any questions raised.

7.6. RECORDING OF AN OPERATION

7.6.1. The notification shall be given in writing whenever possible before carrying out an operation. The notification shall be given orally if there is insufficient time before the operation is scheduled to take place for notification to be given in writing. If either the Distributor or the System Operator requests it shall be submitted as soon as possible, after the system has returned too normal, in writing.

7.6.2. The System Operator shall maintain a database of notifications on the System.

7.7. TIMING IN RESPECT OF AN OPERATION

7.7.1. A notification shall be given as far in advance as possible and in any event shall be given in sufficient time as will reasonably allow the recipient to consider and assess the implications and risks arising.

7.8. NOTIFICATION OF EVENTS

7.8.1. The System Operator shall notify the Distribution Network Operators and Customers Connected to the Transmission System of events which in the reasonable opinion of the System Operator are significant system incidents having an operational effect on the Distributors.

7.8.2. The Distribution Network Operators and Customers Connected to the Transmission System shall notify the System Operator of events which may be significant system incidents affecting the Transmission System. The System Operator may use this information in notifying any other Users of the event.

7.9. FORM OF NOTIFICATION OF AN EVENT

7.9.1. A notification of an event shall describe the event clearly. The information shall be of sufficient detail to enable the recipient of the notification to consider and assess the implications and risks arising.

7.9.2. A notification shall include the name of the individual reporting the event on behalf of the System Operator or the Distributor, as the case may be.

7.9.3. The recipient of the notification may ask questions to clarify the notification and the System Operator or the Distributor shall answer any questions raised.

7.10. PROVISION OF FURTHER INFORMATION

7.10.1. The System Operator shall provide additional information to a Generator after the Generator has reported an event. The Generator may request the fault level at the time of the incident to perform more accurate assessments following an event.

7.11. RECORDING OF AN EVENT

7.11.1. Notification of an event shall be given orally in the first instance. Significant System incidents must be reported in writing if requested by either the Distributor's or the System Operator.

7.11.2. The System Operator shall maintain a database of events on the system.

7.12. TIMING IN RESPECT OF AN EVENT

7.12.1. A notification of an event shall be given as soon as practicable after the occurrence of the event. A notification of an event shall be given within fifteen minutes, except in an emergency.

7.13. OPERATIONAL COMMUNICATION AND DATA RETENTION

7.13.1. It is necessary that adequate communication facilities and procedures be established between the System Operator, Distributors and Generators to allow for the timely transfer of information, in order that the System Operator may fulfil its obligations with regard to the operation of the Transmission System. These communication facilities and procedures shall be in accordance with Part 6 of the Market Rules.

7.13.2. The objectives are:

- (a) To establish contact locations for the System Operator and each class of Participant;
- (b) To detail the communication facilities required between the System Operator and each class of Participant;
- (c) To establish the general procedures for communication of information between the System Operator and Users;
- (d) To establish the general procedures for the authorisation of the System Operator personnel to act on behalf of the System Operator, and Distributor's personnel to act on behalf of the Distributor's in the communication of information between the System Operator and Users; and
- (e) To establish the general procedures for the retention of data.

7.13.3. Both the System Operator and Users shall be obliged to adopt the use of new technologies and methodologies for communication of information, where there is a recognisable benefit from doing so, and to do so would be reasonable in the circumstances.

7.14. CONTACT LOCATIONS

7.14.1. The System Operator

The contact location within the System Operator for communication on matters pertaining to the real-time operation of the Transmission System shall be the National Control Centre (NCC) or if designated the Emergency Control Centre (ECC).

The System Operator shall, from time to time, notify all the Distributors and Generators of the relevant details of contact in the System Operator.

The System Operator shall, from time to time, distribute to each Distributor and Generator an organisational chart and list of personnel and contact numbers in order to assist the Distributors and Generators in communicating with the System Operator.

7.14.2. Generators

The Generators' contact locations and personnel shall be notified to the System Operator by the Generator prior to connection and thereafter it shall be updated as appropriate.

The Generator shall be required to provide a control Facility (control room to control the generating plant). The Generator shall ensure by acting in accordance with Good Utility Practice that the control Facility is staffed at appropriate staffing levels at all times.

The control Facility shall be staffed by a responsible operator(s) who shall respond to communications from the System Operator without undue delay. The operators shall be of suitable experience and training and shall be authorised to perform the following functions on behalf of the Generator:

- (a) To accept and execute Dispatch Instructions; and
- (b) To receive and acknowledge receipt of requests, for amongst other matters, operation outside the registered values of Availability, Ancillary Service capability, or operating characteristics of the Generating Units during System Emergency Conditions as stipulated in Appendix 9.

At any point in time, a single person shall be designated as the Responsible Manager by the Generator and notified to the System Operator. The Responsible Manager shall be responsible for dealing with the System Operator on matters relating to the Grid Code. In the event that the Responsible Manager is not a person on duty at the control Facility, then the Responsible Manager must be capable of being contacted from the control Facility at all times. In the event that the System Operator issues a request to the control Facility requiring the Responsible Manager to contact the NCC, the Responsible Manager shall comply with the request without undue delay and in any case within 15 minutes of the request.

The Responsible Manager shall be authorised by the Generator to perform the following functions on behalf of the Generator:

- (c) To make estimates in accordance with Good Utility Practice as to the Availability, Ancillary Service capability and operating characteristics of each Generating Unit;
- (d) To make declarations for each Generating Unit; and
- (e) To communicate with respect to issues regarding Outages of each Generating Unit. The Generator may, from time to time, notify a replacement contact location and personnel, which meets the foregoing requirements.

7.14.3. Customers Connected to the Transmission System

The Customer Connected to the Transmission System shall notify the System Operator of its contact locations and the detail of its personnel prior to connection and thereafter it shall be updated as appropriate.

The Customer Connected to the Transmission System is required to provide the System Operator with the contact information of a responsible operator(s) who shall respond to communications from the System Operator without undue delay. The operators shall be of suitable experience and training and shall be authorised to perform functions on behalf of the Customer Connected to the Transmission System.

The responsible operator shall have the ability to attend to the site of the Customer Connected to the Transmission System within 60 minutes of an instruction being issued by the System Operator.

At any point in time, the Customer Connected to the Transmission System shall notify the System Operator of a single person designated by the Eligible Customer as the Responsible Manager. The Responsible Manager shall be responsible for dealing with the

System Operator on matters relating to the Grid Code. In the event that the Responsible Manager is not a person on duty at the site of the Customer Connected to the Transmission System, then the Responsible Manager must be capable of being contacted from the site of the Customer Connected to the Transmission System at all times. In the event that the System Operator issues a request to the site of Customer Connected to the Transmission System requiring the Responsible Manager to contact the NCC, the Responsible Manager shall comply with the request without undue delay and in any case within 15 minutes of the request.

7.14.4. Distribution Network Operators

The Distribution Network Operators shall notify the System Operator of its contact locations and the detail of its personnel prior to connection and thereafter it shall be updated as appropriate.

The Distribution Network Operators shall be required to provide a control Facility.

The Distribution Network Operators shall ensure by acting in accordance with Good Utility Practice that the control Facility is staffed at appropriate staffing levels at all times.

The Distribution Network Operators shall operate its control Facility according to the provisions agreed upon with the System Operator as set out in the Distributor's and the System Operator agreement.

7.15. COMMUNICATION FACILITIES

7.15.1. All communication facilities to be provided shall be in accordance with the Market Rules.

7.15.2. All Equipment to be provided by the Distributors and Generators shall comply with the applicable International Telecommunications Union (ITU) and International Electrotechnical Commission (IEC) standards. This shall apply for SCADA and communications equipment and shall meet such standards as notified in advance by the System Operator of their design or procurement and shall be provided at the cost of the Distributor's and Generators, except where otherwise specified.

7.16. SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

7.16.1. SCADA remote Terminal Equipment shall be required in the control room of the System Operator Transmission Station at the Distributor's site for the transmission of signals and indications to and from the NCC. The signals and indications, which must be provided by Distributor's and Generators for transmission by SCADA equipment to the NCC, shall be the signals and indications as agreed to by the System Operator and may from time to time be changed by agreement.

7.16.2. Interface cabinets shall be installed in the control room of the System Operator Transmission Station at the Distributor's site and also on the Distributor's site. Provision and maintenance of wiring and signalling from the Generator's plant and apparatus to the

Distributor's interface cabinet shall be the responsibility of the Distributor. The System Operator shall provide the cables to interconnect these interface cabinets.

7.17. COMPUTER EQUIPMENT

7.17.1. Each Distributor shall comply with the System Operator requirements and provide appropriate computer and data networking equipment to allow data exchange, such as electronic mail, Dispatch Instructions etc. between the System Operator and the Distributor. The Distributor's shall only use this Equipment for operational communications with the System Operator.

7.17.2. Each Distributor shall be responsible for optimising the Reliability and security of the computer equipment including the provision, at no charge, of an uninterruptible power supply.

7.18. TELEPHONE/FACSIMILE

7.18.1. Each Distributor's shall be responsible for the provision and maintenance of telephone and facsimile equipment.

7.18.2. The System Operator shall provide one or more telephone extension to be connected to the System Operator private operational telephone system. This Facility shall be reserved for operational purposes only, and shall be attended continuously by an authorised operational person and answered without undue delay. Distributors shall be responsible for optimising the Reliability and security of this telephone service including the provision at no charge of an uninterruptible power supply.

7.18.3. Distributors and Generators shall provide a public switched telephone network circuit to the communications and control room.

7.18.4. Distributors and Generators shall provide no less than two separate public switched telephone network circuits to the control Facility.

7.18.5. Distributors and Generators shall provide no less than one facsimile unit, connected to a dedicated public switched telephone network circuit at the control Facility.

7.19. ACCESS AND SECURITY

7.19.1. All SCADA, metering equipment, computer and communications equipment that interface with the System Operator and the information carried by it must be secured against unauthorised access. Procedures governing security and access shall be agreed with the Distributor's and Generators in the operation instructions, but shall allow for adequate access to the Equipment and information by the System Operator for the purposes of maintenance, repair, testing and the taking of readings.

7.20. TIME STANDARDS

7.20.1. Time shall be set by a standard determined by the System Operator. The time standard shall be broadcast to relevant telecommunications devices in order to maintain time coherence.

7.21. COMMUNICATION BETWEEN THE USERS

7.21.1. Communication between the System Operator, the Distributors and Generators on matters pertaining to the real-time operation of the Transmission System shall take place between the NCC and the Distributor's and Generator's control Facility, unless where specifically provided for in other sections of this Code.

7.21.2. The System Operator shall ordinarily notify the Distributors and Generators as soon as practicable after the decision to move the NCC to a different location. This shall be no less than seven (7) days prior to the move, but in the event of an emergency it may instead notify them as soon as practicable after the move.

7.21.3. All instructions given by NCC and communications between NCC and the Distributor's and Generators control facilities shall be given by means of the specified communication facilities, unless otherwise specified in the Grid Code.

7.21.4. The System Operator, the Distributor's and Generators shall accept any automatic recording of communications given by means of telephony, electronic means, facsimile transfer or telex as evidence of instructions or communications.

7.22. DATA AND NOTICES

7.22.1. Data and notices shall be submitted in accordance with relevant rules and procedures.

7.22.2. Data and notices to be submitted to the System Operator, or to the Distributors and Generators under the Grid Code shall be in writing and shall be delivered by hand or sent by pre-paid post, by telex, receipted email or facsimile transfer.

7.22.3. Data and notices to be submitted to the System Operator under the Grid Code shall be addressed to the person, and at the address, notified by the System Operator to the Distributor's and Generators for such purpose in their respective Agreements.

7.22.4. Data and notices to be submitted to the Distributors and Generators under the Grid Code shall be addressed to the representatives of the Distributors and Generators as nominated in the Agreements. Or to such other person or address as the Distributors and Generators may notify to the System Operator from time to time.

7.22.5. All data items, where applicable, shall be referenced to nominal Voltage and Frequency unless otherwise stated.

7.22.6. All operational data shall be supplied in accordance with the timetables as set out in the Grid Code.

7.23. DATA RETENTION

7.23.1. This provision has to be read in conjunction with the Market Rules to form the complete requirement with regard to data retention.

7.23.2. Operational data is all data to be supplied by Users under this Code and any other data expressly provided to be operational data under this Code. Operational data to be supplied by the Distributors, Eligible Customers and Generators shall be submitted to the department or address as the System Operator may from time to time advise.

7.23.3. The Users shall keep all operational data confidential.

7.23.4. System Operator shall maintain a complete and accurate record of all operational data supplied or maintained under the Grid Code. The format for the retention of records shall be as the System Operator may reasonably determine. All operational data shall be maintained for a period of no less than five (5) years commencing from the date the operational data was first supplied (or first created, if earlier).

The System Operator shall allow the Users access to its records (and copies thereof) of operational data and/or data required to be maintained on reasonable notice.

8. SECTION: SCHEDULING AND DISPATCH

8.1. OBJECTIVE

8.1.1. The objective of this section is to provide Generators with provisional running orders for the Dispatch Day such that Generating Units will be made available in the correct time scale to enable the System Operator to Dispatch them whilst maintaining the required Operating Reserve. In order to achieve the primary objective this section details the time scale for the System Operator to make specific information available to Generators and Users.

8.1.2. A further objective of this section is to establish a framework to enable the System Operator to issue Dispatch Instructions to:

- (a) Generators with respect to their Generating Units; and
- (b) Users in relation to Ancillary Services.

Dispatch Instructions are issued such that available Generation is matched to Demand with appropriate margin of Operating Reserve whilst maintaining the integrity and security of the Transmission System with acceptable Quality of Supply.

8.2. GENERAL

8.2.1. The System Operator shall dispatch generators according to Market Rules, subject to constraints of safety of personnel, equipment, system security, reliability and the environmental requirements.

8.2.2. The scheduling and Dispatch of Generating Units is necessary to ensure that the most economical combination of Generating Units possible is used for each Dispatch Period. This optimal combination of Generating Units must meet the Demand such that the necessary Frequency Control can be achieved.

8.2.3. In order to achieve this, the System Operator will have to calculate the optimal combination of Generating Units on a continuous basis using specialised software suitable for this. These calculations by the System Operator are based on Day-ahead Nominations by each Generator and the anticipated Demand.

8.3. DATA AND PROCESS

8.3.1. The System Operator shall forecast the Power System Demand in accordance with Condition 7.4.5 that shall be used in the Dispatch process.

8.3.2. System Operator shall set the level of Reserve that shall be used in the Dispatch process.

8.3.3. System Operator shall include in the Dispatch Instructions the Active Power Output level of a Generating Unit, Synchronising or Desynchronising time, if appropriate and Ancillary Service to be provided.

8.3.4. System Operator shall adjust Generation Unit Active Power Output by using a merit order based on the Day-ahead Nominations provided by Generators for each Generating Unit as variations occur due to such factors as Demand or Availability variations.

8.4. DISPATCH SCHEDULING

8.4.1. Production of a Dispatch Schedule

Each day between 13:00 hours and 16:00 hours the System Operator shall produce the two Dispatch Schedules pursuant Conditions 12.4.2 and 12.4.3 for the Dispatch Day. The System Operator may produce the Dispatch Schedule more or less frequently, or reasonably delay its production in response to changes in Availability and other events that may arise. The Dispatch Schedule is utilised by the System Operator in its scheduling and in its preparation for Dispatch of Generating Units.

In preparing the Dispatch Schedule, the System Operator shall schedule Day-ahead Nominations to minimise the offered cost of meeting Load forecast according to the principles set out in section 6.3, taking into account the following factors:

- (a) Forecast Demand and geographical Demand distribution;
- (b) Generating Units' Registered Information, including operating characteristics, Ancillary Service capability and Availability;
- (c) Generator Day-ahead Nominations, including Nominations by Hydro Generating Units;
- (d) Declared abnormal risks to Generating Units;
- (e) Ancillary Service requirements, including Frequency Control, Operating Reserve and Voltage Control;
- (f) Reliability Must-run requirements;
- (g) Transmission System constraints, including Network and Generating Unit constraints;
- (h) Transmission System losses;
- (i) System Operator and Users' monitoring and test requirements;
- (j) Transmission System stability implications;
- (k) Interconnector Capacity Entitlements and Interconnector Energy Trade Nominations pursuant to Rule 7.10 of the Market Rules;
- (l) Interconnection Agreements;
- (m) Other factors as may be reasonably considered by the System Operator to be relevant to the Dispatch Schedule.

8.4.2. Pre-dispatch Day constrained Schedule

The System Operator shall produce a Pre-dispatch Day constrained Schedule for each Dispatch Day by 16:00 hours on the Pre-dispatch Day.

The System Operator shall issue provisional running orders based upon the Dispatch Schedule for the Dispatch Day to each Generating Unit by 16:00 hours on the Pre-dispatch Day.

The provisional running orders issued to each Generating Unit by the System Operator, shall indicate the planned Load pattern specifying:

- (a) Forecast start-up and shut-down times, if relevant;
- (b) Forecast Active Power Dispatch levels for each Dispatch Period; and,
- (c) Forecast levels of Operating Reserve provision for each Dispatch Period, if the Generating Unit is contracted for Operating Reserve requirements.

Provisional running orders are indicative only, provided as a guide to the expected output requirements from Generating Units and are not Dispatch Instructions.

8.4.3. Pre-dispatch Day unconstrained Schedule

The System Operator shall produce a Pre-dispatch Day unconstrained Schedule for each Dispatch Day by 16:00 hours on the Pre-dispatch Day. The same principles specified in section 8.4.1 shall be applied with the following change:

- (a) The known Transmission System constraints must be excluded.

This Schedule shall be used to forecast the Day-ahead Price consistent with the appropriate Market Rules.

8.4.4. Dispatch Day schedule

If the System Operator forecasts a significant difference between the provisional running orders and anticipated Dispatch Instructions, in the interval between the issue of provisional running orders and the issue of relevant Dispatch Instructions, the System Operator shall endeavour to notify this difference to impacted Generators.

8.4.5. System congestion

System Operator shall install and commission such real time equipment and software as to calculate Transmission System restrictions and Reliability margins per Dispatch Period.

System Operator shall change the Dispatch Schedule of the Generators in order to eliminate transmission congestion and to ensure the security and Reliability of system operation.

System Operator shall reduce the Transmission Services contributing to the congestion if it was not possible to eliminate congestion by changing the scheduling of the Generators.

System Operator shall further instruct all Users, independent of the transmission services, to take specific action in order to avoid more major disturbances in emergency situations.

8.4.6. Ex-post Unconstrained Dispatch Schedule

The System Operator shall produce an Ex-post Unconstrained Dispatch Schedule for each Dispatch Day by no later than 12:00 hours on the Calculation Day. This leaves the

System Operator sufficient time to calculate the System Marginal Price for each Dispatch Period pursuant Rule 11.2.1 of the Market Rules. The same principles specified in section 8.4.1 shall be applied with the following two changes:

- (a) The actual Load readings must be used; and
- (b) The Transmission System constraints must be excluded.

8.5. GENERATION DISPATCH

8.5.1. Dispatch Instructions To Generators

The System Operator shall issue Dispatch Instructions relating to the Dispatch Day at any time during the period beginning immediately after the issue of the Dispatch Schedule in respect of that Dispatch Day.

The System Operator shall give a Dispatch Instruction to a Generator for a specific Generating Unit to change the output of Active Power, Reactive Power or an instruction to provide an Ancillary Service.

The System Operator shall give Dispatch Instructions to a Generator orally, by phone or by electronic means including by means of Automatic Generation Control. The Dispatch Instruction shall identify the relevant Generating Unit by specifying the Generator's and Generating Unit's unique identification number pursuant Rule 4.5.1 of the Market Rules.

A Generator shall immediately and formally acknowledge a Dispatch Instruction in respect of a Generating Unit by telephone, or immediately provide a reason for non-acceptance. The reason for non-acceptance shall only be on safety grounds (relating to personnel or plant) or because the Dispatch Instruction is not in accordance with the Nomination or the Registered Information relevant to the time and period to which the Dispatch Instruction relates.

The System Operator shall be notified without delay by telephone in the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on safety grounds (relating to personnel or plant).

The System Operator shall maintain a record of all daily Dispatch Instructions issued to Generators.

8.5.2 Generation Synchronising and Desynchronising Times

The System Operator shall determine the required Synchronising and Desynchronising times for Generating Units.

The System Operator shall issue Dispatch Instructions to Generators to Synchronise (or Desynchronise) specific Generating Units in accordance with their Registered Information.

If a Dispatch Instruction to a Generator to Synchronise a specific Generating Unit does not also contain an Active Power Output to be achieved then it shall be assumed that the

instruction is to increase output (following Synchronisation) up to the level of minimum generation of the Generating Unit as specified in the Registered Information.

The Generator shall immediately (at the time the discrepancy is identified) inform the System Operator of a situation and estimate the new Synchronising time, where Synchronising time issued by the System Operator to a Generator for a specific Generating Unit and the Generator identifies that the Generating Unit will not be Synchronised within ± 10 minutes of the instructed time.

The allowable tolerance appropriate to Synchronising times shall be based on the times set out in the Registered Information.

8.5.3 Generation Active Power Dispatch

Based on the Day-ahead Nominations of the Generators, on System conditions, and on other factors as may arise from time to time. The System Operator shall issue Dispatch Instructions to a Generator in relation to a specific Generation Unit, which has been instructed to be Synchronised, to adjust its Active Power Output.

When a Generator has received and accepted a Dispatch Instruction for a Generating Unit to change the level of Active Power it shall without delay adjust the level of output of the Generating Unit to achieve the new target in line with its Registered Information and its Quantity Nomination.

A Generating Unit shall be deemed to have complied with a Dispatch Instruction when it achieves an output within the allowable tolerance as specified in Rule 12.5.1 of the Market Rules. Deviations outside the allowable tolerance band will be treated according to Rule 12.2.1(c) of the Market Rules.

The adjustment of Active Power Output of a Generating Unit operating in a Frequency sensitive mode for System Frequency other than an average of 50Hz, shall be made in accordance with the current registered value of Governor Droop for the Generating Unit.

The System Operator shall be notified immediately by telephone in the event that while carrying out the Dispatch Instruction an unforeseen problem arises caused by safety reasons (relating to personnel or plant).

8.5.4. Generator Reactive Power Dispatch

The System Operator shall issue Dispatch Instructions to Generators to adjust the Reactive Power output of any Generating Unit that has been instructed to be Synchronised.

- (a) A Generator shall be able to provide Reactive Power without having to produce or consume a large quantity of real power. The System Operator shall control the amount of reactive power. This may be done directly through the energy management system or by telephone.
- (b) When a Generator is generating, Reactive Power supply is mandatory in the full operating range as specified in the Code.
- (c) Voltage control and the supply or consumption of Reactive Power are inter-related in the sense that the voltage is affected by changes in the Reactive Power flow. System stability depends on the voltage profile across the System. In view of these considerations it is necessary from time to time to employ certain power

stations to supply or consume Reactive Power, whether or not they are producing Active Power, for the purpose of Voltage Control.

The Reactive Power output of any Generation Unit in respect of which a Dispatch Instruction is given shall then, without delay be adjusted in accordance with its Registered Information, to the new target Reactive Power so instructed, within, a tolerance of $\pm 2\%$ of the target or $\pm 2\text{MVAR}$ whichever is greater. The Reactive Power output of a Generating Unit shall not be adjusted (other than under AVR action) other than in response to a Dispatch Instruction from the System Operator.

Generators having achieved the new target Reactive Power output should not attempt to sustain this level of Reactive Power output as the System Voltage varies but should, rather, allow the Reactive Power output to vary under AVR control in accordance with registered Ancillary Service capabilities in the Registered Information.

While a Reactive Power Dispatch Instruction shall normally specify a new Reactive Power target for a Generating Unit, the System Operator shall also from time to time instruct Generators to perform one or more tap changes on the Generator Transformer of a Generating Unit. The instruction for tap changes may be a simultaneous tap change instruction whereby the tap change shall be effected by the Generator in response to an instruction from the System Operator issued simultaneously to relevant Power Stations. The instruction, which is normally preceded by advance warning, shall be effected within 1 minute of receipt from the System Operator of the instruction.

Dispatch Instructions in relation to Reactive Power shall include target Voltage levels to be achieved by the Generating Unit on the Transmission System at Connection Point (or on the Participant System at the Participant System Entry Point in the case of a Distribution Embedded Generator, namely on the higher voltage side of the Generator step-up transformer). Where a Generating Unit is instructed to a specified target voltage, the Generator shall achieve that target within a tolerance of 1 kV by tap changing on the Generator step-up transformer unless otherwise agreed with the System Operator. Under normal operating conditions, once this target Voltage level has been achieved, the Generator shall not tap change again without prior consultation with and agreement of the System Operator.

Under certain conditions such as low System Voltage, an instruction to maximum Reactive Power output at instructed Active Power Output shall be given and the Generator shall take appropriate action to maximise Reactive Power output unless constrained by plant operational limits or safety grounds relating to personnel or plant.

Under certain conditions such as high System Voltage, a Dispatch Instruction to maximum Reactive Power absorption at instructed Active Power Output shall be given and the Generator shall take appropriate action to maximise Reactive Power absorption unless constrained by plant operational limits or safety grounds relating to personnel or plant.

The issue of Dispatch Instructions for Active Power shall be made with due regard to any resulting change in Reactive Power capability and shall include reduction in Active Power Generation in order to increase Reactive Power capability.

The excitation system, unless otherwise agreed with the System Operator, shall be operated only in its constant terminal voltage mode of operation with Reactive Power limiters in service, with any constant Reactive Power output control mode or constant power factor output control mode always disabled, unless agreed otherwise with the System Operator. In the event of any change in System Voltage, a Generator shall not take any action to override automatic Reactive Power response which is produced as a result of constant terminal voltage mode of operation of the automatic excitation control system unless instructed otherwise by the System Operator or unless immediate action is necessary to comply with stability limits or unless constrained by plant operational limits or safety grounds (relating to personnel or plant).

A Dispatch Instruction relating to Reactive Power shall be implemented without delay and will be achieved not later than 2 minutes after the instruction time, or such longer period as the System Operator may instruct.

Where Dispatch Instructions relating to Active Power and Reactive Power are given together, and to achieve the Reactive Power output would cause the Generating Unit to operate outside Dispatch Scheduling and Dispatch parameters as a result of the Active Power instruction being met at the same time, then the timescale of implementation of the Reactive Power instruction shall be extended to be no longer than the timescale for implementing the Active Power instruction but in any case to achieve the Reactive Power Dispatch Instruction as soon as possible.

In circumstances where the System Operator issues new instructions in relation to more than one Generating Unit at the same Power Station at the same time tapping shall be carried out by the Generator one tap at a time either alternately between (or in sequential order, if more than two), or at the same time on, each Generating Unit, as the case may be.

Where the instructions require more than two taps per Generating Unit meaning that the instructions cannot be achieved within 2 minutes of the instruction time, (or such longer period at the System Operator may have instructed), the instructions shall each be achieved with the minimum of delay after the expiry of that period.

On receiving a new Active Power Dispatch Instruction, no tap changing shall be carried out to change the Reactive Power output unless there is a new Reactive Power Dispatch Instruction.

Where an instruction to Synchronise is given, or where a Generating Unit is Synchronised and a Active Power Dispatch Instruction is given, a Reactive Power Dispatch Instruction consistent with the Generating Unit's relevant parameters shall be given. In the absence of a Reactive Power Dispatch Instruction with an instruction to Synchronise, the Reactive Power output should be 0 MVar.

Where an instruction to Desynchronise is given, a Reactive Power Dispatch Instruction, compatible with shutdown, shall be given prior to Desynchronisation being achieved. In the absence of a separate Reactive Power Dispatch Instruction, it is implicit in the instruction to Desynchronise that Reactive Power output should at the point of Synchronism be 0 MVar at Desynchronisation.

It should be noted that should System conditions require, the System Operator shall need to instruct maximum Reactive Power output to be achieved as soon as possible, but in any event no later than 2 minutes after the instruction is issued.

On receipt of a Dispatch Instruction relating to Reactive Power, the Generator shall take such action as is necessary to maintain the integrity of the Generating Unit (including, without limitation, requesting a revised Dispatch Instruction), and shall contact the System Operator without delay.

Reactive Power Dispatch Instructions issued by the System Operator shall reflect the limits contained in the Registered Information regarding Ancillary Service capabilities and Quantity Nominations.

Under System fault conditions it is possible for AVR action to drive Reactive Power output for a Generating Unit outside of its limits as contained in its Registered Information. The Generator shall immediately inform the System Operator of the situation. However if the Generator reasonably believes that the situation may be dangerous to personnel or plant, then limited action shall be taken to improve the situation.

8.5.5. System alerts

The System Operator shall notify Generators, by one of several means, of the existence of a System Emergency Condition.

8.5.6. System Emergency Conditions

The System Operator may instruct Generators to operate outside the limits implied by the then current Registered Information in order to maintain Transmission System integrity under System Emergency Conditions.

Where the System Operator has issued an emergency instruction requiring operation of a Generation Unit outside the limits applied by the then applicable Quantity Nomination and Registered Information, then the Generator shall comply with the emergency instruction if, in the reasonable opinion of the Generator, the safety of personnel, and/or plant is not compromised in complying with the request.

8.5.7. Failure To Comply With A Dispatch Instruction

The Generator shall inform the System Operator by telephone without delay if at any time a Generating Unit is unable to comply with any Dispatch Instruction correctly issued by the System Operator in respect of any Generating Unit.

8.5.8. Constrained Generation

Constrained generation is the service supplied by a Power station to the System Operator by constraining its power output below (alternatively above) the unconstrained schedule level. The service is required to ensure that the Transmission Network remains between appropriate operational limits (e.g. thermal, voltage or stability limits).

In providing the service, the Power station experiences a financial loss, for which it shall be compensated by the Transmission Network according to the market rules. Constrained

generation is required to meet network Reliability as there are no current rules for market splitting across transmission constraints or the handling of *units* in strategic positions.

The identification of the specific Transmission Network constraints applicable at any point in time shall be the responsibility of the System Operator.

9. SECTION: OUTAGE CO-ORDINATION

9.1. OBJECTIVE

9.1.1. The objective of this section is to define the requirements for formal notification of Outages by Generators to the System Operator.

9.2. GENERAL

9.2.1. Secure operation of an electricity system requires that the maintenance of the Generating Units should be co-ordinated with the Outages of critical Transmission lines. This is essential in order to enable the System Operator to fulfil its obligations relating to the operation of the Transmission System, and to enable Generators to plan their Outages in an orderly way. The mechanisms by which this is achieved will be formalised in this section.

9.3. OUTAGE SCHEDULING

9.3.1. The System Operator, Distributors and Generators shall establish schedules for inspection and preventive maintenance of its Generation, Transmission, protection, control, communication and other auxiliary systems. These maintenance and inspection schedules shall be co-ordinated to ensure an equipment Outage pattern that shall not violate Power System Reliability.

9.3.2. Planning and co-ordination

The System Operator shall co-ordinate all Outage plans for the Distributors and Generators on an annual basis. These plans shall be ready by October of every year. The System Operator shall then be responsible to perform pertinent Reliability studies to ensure the secure operation of the Power System during the Outages as has been agreed in the annual Outage plans.

Scheduled Generation and Transmission Outages that may affect the Reliability of Power System operations shall be planned and co-ordinated (notification of cancellation at least 24 hours in advance) amongst affected parties. Special attention shall be given to results of pertinent studies. The Planned Outage shall be advised at least 2 weeks in advance and confirmed in writing. The System Operator shall advise all the Distributors and Generators of the return of any of the equipment.

9.3.3. Voltage regulating equipment

System Operator shall co-ordinate all scheduled Outages of System voltage regulating equipment, such as automatic voltage regulators on Generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc.

9.3.4. Metering and control equipment

The System Operator shall co-ordinate scheduled Outages of metering and control equipment and associated communication channels.

9.3.5. Generator requirements

- (a) Generators shall specify with regard to each of their Generating Units, the start date, time and duration of each Outage. In pursuant of Section 10.3.1, statutory Outage plans for Generating Units for subsequent years after the current year must reach System Operator by 1st of August of the current year.
- (b) Each Generator shall act in accordance with Good Utility Practice in planning their Outages. In particular, so as to avoid a situation arising in which a Generator is obliged to schedule an Outage at short notice by reason of obligations imposed upon the Generator by statute as a consequence of the Generator not having planned in accordance with Good Utility Practice.
- (c) Generators shall specify the following, unless they reasonably substantiate that an Outage is inflexible:
 - (i) An alternative preferred windows of opportunity within the year for any Outage;
 - (ii) The minimum Outage duration which would be acceptable, if less than the scheduled Outage duration;
 - (iii) Situations where the paralleling of Outages of two or more of its Generating Units may be required, desirable, undesirable or not possible;
 - (iv) A priority order associated with the various Outages scheduled by the Generator; and
 - (v) Any Outages where it is particularly desirable that they should take place within the year scheduled.
- (d) Any Outage where its timing is dependent on Generating Unit run hours, equivalent run hours or starts.

9.3.6. Distribution Company requirements

Each Distribution Company shall act in accordance with Good Utility Practice in planning their network line Outages. Information shall be furnished by 1st of August of each year:

- (a) Load in MW not to be available from any connection point.
- (b) Identification of equipment / apparatus at connection point where there will be outage
- (c) Period of which network line will be unavailable with Start-date and Start-time and End-date and End-time.

9.3.7. Outage scheduling program

The System Operator shall present the co-ordinated Outage plans as well as the results of the Reliability studies in report format to the Commission for approval.

9.4. CHANGES TO THE COMMITTED OUTAGE SCHEDULING PROGRAM

9.4.1. System Operator change request

The System Operator can, providing the relevant reasons, request a Generator to change the timing or duration of any Outage of one of the Generator's Generating Units in the Outage scheduling program.

9.4.2. Generator response

A Generator may respond either by declining the request, or by agreeing to the request. Generators shall make every reasonable effort to co-operate with reasonable changes requested by the System Operator.

9.4.3. Agreement to conditions

If a Generator responds by agreeing to the request subject to specific conditions, the System Operator may respond by either confirming agreement to those conditions or by declining agreement. Where the System Operator agrees to the conditions, then the Outage scheduling program shall be amended accordingly. Where the System Operator declines to agree to the conditions, then the System Operator may negotiate with the Generator as to revised or alternative conditions, which would be acceptable.

9.4.4. Generator change request

A Generator may at any time request the System Operator for a change in the timing or duration of any Outage of one of the Generator's Generating Units in the Outage scheduling program. The System Operator may accept or decline the request. The Outage scheduling program shall be amended accordingly or the System Operator shall negotiate with the Generator conditions, which shall be acceptable to both parties.

9.4.5. Deviations from Outage scheduling program

The System Operator shall compile an annual report to indicate how the Outage scheduling program of the previous year was adhered to. Specific reasons shall be provided for each deviation to the original approved Outage scheduling program.

The Commission shall review this report in order to ensure the improvement of the System Operator's performance over a number of years.

9.5. OTHER INFORMATION TO BE NOTIFIED

9.5.1. Ancillary Services

Generators shall inform the System Operator of any proposed maintenance, in addition to Outages, which shall, or is likely to, affect the capability of the Generating Unit to provide Ancillary Services.

9.5.2. Security of supply

The System Operator shall request alterations to maintenance, where security of supply or the secure operation of the Transmission System would be at risk. The System Operator shall make reasonable endeavours to give as much notice as possible for such requests for alterations. Where the System Operator makes such a request, the Generator shall use reasonable endeavours to comply with the request in arriving at the Generator's final program for such maintenance.

10. SECTION: RELIABILITY MEASURES

10.1. OBJECTIVE

10.1.1. The objective of this section is to define the Reliability criteria and measures the System Operator and the TSP have adhere to in operating, maintaining and developing of the Transmission System.

10.2. GENERAL

10.2.1. In order to maintain reliable operation of the Transmission System, it is necessary that all systems observe and subscribe to certain minimum planning criteria.

10.2.2. The criteria and principles provided in this document serve as a guideline to develop criteria and methodologies applicable to the TSP, System Operator, Users and related Interconnections.

10.2.3. Reliability measures

Traditionally the measurement of transmission Reliability is achieved through the deterministic N-1 Criteria. This criterion should be regarded as a minimum standard. Additional to this the System Operator should develop probabilistic criteria. The fundamental attributes for Reliability measures to be considered to evaluate risk of probable extreme events include:

- (a) The Frequency of events (e.g. frequency of circuit overload – 0.72 events/year);
- (b) Duration of events (e.g. duration of circuit overload – 2.5 hours/year); and
- (c) Severity of events (how does event impact on load curtailment)

From these attributes other indices to quantify network performance can be calculated. To enable the definition of applicable indices, which may apply to the TSP and System Operator, a number of concepts and definitions related to network, configuration and aspects influencing network performance are discussed in Appendix 3.

10.3. APPLICABLE RELIABILITY CRITERIA

10.3.1. The System Operator shall study and assess the overall Reliability (adequacy and security) of the Power System, both existing and as planned, to ensure that the Power System development conforms to the Transmission Planning Criteria.

10.3.2. The System Operator shall develop Applicable Reliability Criteria for the Nigerian Transmission System for approval by the Commission.

10.4. RELIABILITY INDICATORS

10.4.1. The Applicable Reliability Criteria as stated in Appendix 3.1.2 shall specify specific measurable Reliability indicators. These can be expanded based on the System Operator, TSP and Users' needs. All of these indicators can be calculated for a defined recording period. The length of the period should be measured in years to facilitate comparison.

10.5. REPORTING

10.5.1. The System Operator shall prepare and publish an annual assessment report of the Reliability of the Transmission System for review by the Commission.

10.5.2. To carry out these tasks, sufficient data and input must be made available to evaluate and analyse the Applicable Reliability Criteria.

11. SECTION: OPERATIONAL TESTING ON THE NETWORK

11.1. OBJECTIVE

11.1.1. The objective of this section is to establish approach to central co-ordination and control of an operational test required by the System Operator, the TSP or a User, where such test shall or may:

- (a) Affect the secure operation of the Transmission System;
- (b) Have a significant effect on the operation of the Transmission System or a Participant's System;
- (c) Affect the economic operation of the Transmission System or a Participant's System; and
- (d) Affect the quality or continuity of electricity supply to Users.

11.2. GENERAL

11.2.1. This section deals with the responsibilities and procedures for arranging and carrying out operational tests that may have an effect on the systems of the TSP and Users.

11.2.2. By their nature, operational tests may have an impact on either or both of:

- (a) The System Operator's responsibilities in respect of the Transmission System, including Dispatch of Generation; and
- (b) The operations of Users and the quality and continuity of supply of electricity to Users.

11.2.3. To minimise disruption to the operation of the Transmission System and to the Systems of other Users, it is necessary that tests that affect the operation of the Transmission System or Users' Systems be subject to central co-ordination and control.

11.2.4. These tests are not intended to deal with tests that may be called routinely by TSP in order to assess compliance of Users with their design, operating and connection requirements.

11.3. TESTS REQUIRED BY TSP OR SYSTEM OPERATOR

11.3.1. System Operator's responsibility

System Operator as operator of the Transmission System shall carry out operational tests in accordance with Good Utility Practice, in order to maintain and develop operational procedures, to train staff, and to acquire information in respect of Power System behaviour under abnormal system conditions. The System Operator shall endeavour to limit the Frequency of occurrence, scope, extent of effects and type of operational tests to those required by Good Utility Practice.

11.3.2. Range of tests

Operational tests required by the System Operator or the TSP from time to time shall include, but shall not be limited to the following:

- (a) Tests involving the controlled application of Frequency and/or Voltage variations aimed at gathering information on Power System behaviour;
- (b) Power System restoration tests (i.e. Black Start test at power station);
- (c) Testing of standing procedures for System Emergency Conditions; and
- (d) Testing or monitoring of power quality under various Power System conditions and Dispatch configurations.

11.3.3. Notice to Users

Where the System Operator or TSP intends to carry out an operational test, and such test will or may have an operational effect on a Participant's system, the System Operator shall provide notice to the relevant Participant of the scheduled time and effect of the operational test as is reasonable in all the circumstances and shall keep the relevant Participant informed as to any changes to the scheduled time and nature of the operational test.

11.3.4. Request for additional time

A Participant, having been informed about an operational test may contact the System Operator to request additional time to consider the impact of the test on the Participant. The System Operator shall co-operate with the Participant to assess the risks. The test shall not proceed until all Users are satisfied unless, in the System Operator's view, a Participant is acting unreasonably.

11.4. TESTS REQUIRED BY USER(S)

11.4.1. Users' responsibility

Operation of Users' plant in accordance with Good Utility Practice requires operational testing in order to maintain and develop operational procedures, develop and measure plant performance, comply with statutory or other industry obligations and to train staff.

In accordance with Good Utility Practice each Participant shall endeavour to limit the Frequency of occurrence of operational tests and to limit the effects of such operational tests on the Transmission System.

11.4.2. Procedure for requesting operational tests

Users shall submit a request for an operational test in time. As part of the request, the Users, when requesting an operational test, shall supply sufficient detail to the System Operator to allow any operational consequences of the test to be adequately assessed. This shall include the following information:

- (a) The reason for the proposed test;
- (b) The preferred time or times for the test
- (c) The milestones for individual stages of the operational test;

- (d) Whether there may be an adverse material impact on the Participant if the operational test is cancelled at short notice or delayed; and
- (e) Where the Participant is a Generator, the Dispatch or Dispatches required by the Generator for completion of the test.

Additionally, the factors that influence the completion of the stages should be outlined to the System Operator, e.g., if the procedure to be followed for a certain stage depends on the outcome of a previous stage.

11.4.3. Generator Specific request

A request by a Generator for an operational test requiring a Generating Unit to be Dispatched to a particular Active Power output or operating condition shall not be considered a re-declaration of Availability, Ancillary Service capability or operating characteristics.

11.5. EVALUATION OF PROPOSED OPERATIONAL TESTS

11.5.1. Impact assessment

The System Operator shall, on receipt of an operational test request from a Participant, assess the impact of the proposed test on the operation of the Power System. The System Operator may request additional information from the Participant required evaluating the impact of the test.

11.5.2. Objections and sensitivity

The System Operator shall evaluate the impact of the operational test with users that might be significantly affected. Any reasonable objections from any such Users shall be considered. When discussing the operational test with any affected Participant, the System Operator shall not disclose what it reasonably believes to be commercially sensitive or otherwise potentially sensitive information to Users without the consent of the Participant requesting the test.

11.5.3. Generator Dispatch outside currently registered values

Where an operational test requested by a Generator in respect of one of its Generating Units requires a Dispatch that is outside the currently registered values of Availability, Ancillary Service capability or operating characteristics of the Generating Unit, then the System Operator may so Dispatch the Generating Unit for the period required for the operational test.

11.6. APPROVAL FOR OPERATIONAL TESTING

11.6.1. Approval criteria

The criteria for approving operational tests shall include:

- (a) The impact of the operational test on Transmission System operation security;

- (b) The impact of the operational test on Transmission System operation economics;
- (c) The impact of the operational test on other Users' systems; and
- (d) The effect of the operational test on continuity and quality of electricity supply.

11.6.2. Proposed Dispatch procedure

On approval by the System Operator of an operational test requested by a Participant, who is a Generator, the System Operator shall contact the Generator outlining the proposed Dispatch procedure and schedule.

On receipt of the proposed Dispatch procedure and schedule of the operational test, the test requestor shall notify the System Operator without undue delay, of the test requestor's acceptance or rejection of the proposed Dispatch procedure and schedule for the operational test.

11.6.3. Rejection of Dispatch procedure

On notification of rejection of the proposed Dispatch procedure and schedule for the operational test by the test requestor, the operational test shall not take place. The test requestor may enter into discussions with the System Operator as to an alternative schedule for the operational test, or may request a different operational test, or may request the operational test at an alternative time.

11.6.4. Acceptance of Dispatch procedure

On notification of acceptance of the proposed Dispatch procedure and schedule for the operational test by the test requestor, the System Operator shall inform other Users as to the scheduled time and nature of the test, if in the opinion of the System Operator those Users shall or may be significantly affected by the test, or otherwise as dictated by standing arrangements.

11.6.5. Concerns by affected Users

If users that might be significantly affected are not satisfied with the proposed operational test, they shall advise the System Operator of their concerns. The System Operator shall not cancel the proposed operational test unless these objections are reasonable. If operationally affected Users are still not satisfied with the operational test being approved, and then they may appeal the decision to the Commission.

11.7. SCHEDULING OF OPERATIONAL TESTS

11.7.1. Where the System Operator requires an operational test, either:

- (a) The Generator / User shall nominate half-hourly Active Power outputs and constraints and the System Operator shall then Dispatch consistent with the planned operational test, or
- (b) Where operational test costs and conditions have been agreed in advance between the Generator / User and the System Operator, the Generator shall

nominate in accordance with the System Operator requirements for the operational test.

11.7.2. Test prioritisation

The System Operator shall use reasonable endeavours to prioritise operational tests where the test requestor has notified the System Operator that operational tests are required in accordance with licence conditions, statutory regulations or safety Codes or a delay in the execution of the tests may have an adverse material impact on a Participant.

11.8. DISPATCHING OF OPERATIONAL TESTS

11.8.1. Dispatch Instructions

The System Operator shall issue Dispatch Instructions for operational tests in the normal manner for issuing Dispatch Instructions.

The System Operator shall use reasonable endeavours to ensure that scheduled operational tests are Dispatched in accordance with the agreed upon Dispatch procedures.

11.8.2. Revised test procedure

Where the System Operator assesses that the impact of an operational test on Transmission System security or on the continuity and Quality of Supply or operation of a Participant may or is likely to be significantly greater than originally estimated, the System Operator may contact the test requestor to discuss a revised test procedure or schedule.

11.8.3. Possibility of cancellation or postponement

Where the System Operator foresees a requirement or likely requirement to cancel, postpone or otherwise significantly alter an agreed upon Dispatch procedure and schedule, then the System Operator shall inform the test requestor as soon as reasonably possible.

11.8.4. Cancellation, interruption or postponement of test

The System Operator may where it considers it necessary, cancel, interrupt or postpone an operational test at any time, but shall, where possible, utilise the agreed upon procedures prior to taking such action where the cancellation, interruption or postponement is for other than technical reasons.

11.8.5. Cancellation by test requestor

If the test requestor wishes to cancel an operational test either before commencement of the test or during the test, the test requestor shall notify the System Operator. Nominations and Dispatch Instructions shall remain valid when operational tests are cancelled.

11.9. TEST REPORTING

11.9.1. Scheduled completion time

Upon conclusion of the scheduled time for an operational test the test requestor shall notify the System Operator as to whether the test, or sections of the test, if divided into sections, has been completed.

11.9.2. Reporting

At the conclusion of the operational test, the test requestor shall be responsible for preparing a written report on the operational test which shall be available to the System Operator, operationally effected Users and the Commission on request within 30 days of the conclusion of the operational test.

The Report shall include a description of the plant and/or apparatus tested and a description of the system test carried out together with the results, conclusions and recommendations as they relate to the System Operator and operationally affected Users.

11.9.3. Report confidentiality

The Report shall not be submitted to any person who is not a representative of the System Operator or the test requestor unless the System Operator and the test requestor, having reasonably considered the confidentiality issues arising shall have unanimously approved such submission.

11.10. DISPUTES

Disputes shall be handled according to relevant industry rules and regulations as approved by NERC.

12. SECTION: SAFETY AND CO-ORDINATION

12.1. OBJECTIVE

12.1.1. The objective of this Section is to achieve Safety from the network when work on an Equipment necessitates the provision of Safety Precautions on another equipment on the Equipment up to a Connection Point.

12.1.2. A flow chart in Appendix 4 illustrates the process utilised in this code to achieve the objective set out. In the case of a conflict between the flow chart and the provisions of an agreed procedure, the agreed procedure will prevail.

12.2. GENERAL

12.2.1. This Section specifies the standard operating procedures to be used by System Operator, TSP and Users of the network for the co-ordination, establishment and maintenance of necessary Safety Precautions when work is to be carried out on the Transmission Network or a User's apparatus and when there is a need for Safety Precautions on the High Voltage equipment on the other's system for work to be carried out safely. The term "work" includes testing, other than Network Tests. This Section applies between System Operator, TSP and Users and does not impose a particular set of Safety Rules on TSP and Users; the Safety Rules to be adopted and used by TSP and Users shall be those chosen by them. This Safety procedure applies to:

- (a) TSP
- (b) System Operator
- (c) Generators
- (d) Distribution Network Operators
- (e) Customers Connected to the Transmission System

12.3. INTERPRETATION

12.3.1. In this procedure, the following terms shall have the meaning:

- (a) "High Voltage equipment" means High Voltage electrical circuits forming part of a System, on which Safety from the System may be required or on which Safety Precautions may be applied to allow work to be carried out on a circuit.
- (b) "Isolation" means the disconnection of Equipment from the remainder of the network in which the equipment is situated by either of the following:
 - (i) an Isolating Device maintained in an isolating position. The isolating position must either be:
 - b.i.1) maintained by immobilising the Locking and Isolating Device in the isolating position and affixing a Caution Notice to it. Where the Isolating

Device is Locked with a Safety Key, the Safety Key must be secured in a Key Safe. Key Safe must be retained in a safe custody; or

- b.i.2) maintained and/or secured by such other method which must be in accordance with the Local Safety Instructions of TSP or that of the User, as the case may be; or
- (ii) An adequate physical separation which must be in accordance with, and maintained by, the method set out in the Local Safety Instructions of TSP or that of the User as the case may be, and, if it is a part of that method, a Cautious Notice must be placed at the point of separation.
- (c) “Earthing” means a way of providing a connection between conductors and the earth by an Earthing Device which is either:
 - (i) immobilised and Locked in an earthing position. Where the Earthing Device is locked with a Safety Key, the Safety Key must be secured in a Key Safe. Key Safe must be retained in a safe custody; or
 - (ii) maintained and/or secured by such other method which must be in accordance with the Local Safety Instructions of the TSP or that of the User, as the case may be.

12.4. PROCEDURE

12.4.1. Approval of Local Safety Instructions

- (a) In accordance with the timing requirements of its Agreement with the TSP, each User will supply to the TSP a copy of its Local Safety Instructions relating to its side of the Connection Point at each Connection Site.
- (b) In accordance with the timing requirements of each User Agreement, the TSP will supply to each User a copy of its Local Safety Instructions relating to the TSP side of the Connection Point at each Connection Site.
- (c) Prior to connection each party must have approved the other’s relevant Local Safety Instructions in relation to Isolation and Earthing.
- (d) Either party may require that the Isolation and/or Earthing provisions in the other party’s Local Safety Instructions affecting the Connection Site should be made more stringent in order that approval of the other party’s Local Safety Instructions can be given. Provided these requirements are not unreasonable, the other party will make such changes as soon as reasonably practicable.

If approved, a party that wishes to change the provisions in its Local Safety Instructions relating to Isolation and/or Earthing after approval, must inform the other party. If the change is to make the provisions more stringent, then the other party merely has to note the changes. If the change is to relax the provisions, then the other party need to assess and approve the new provisions and procedures referred to in 13.4.1(c).

12.4.2. Safety Co-ordinators

For each Connection Point, the TSP and each User must at all times have person(s) (Safety Co-ordinator(s)) to be responsible for the co-ordination of Safety Precautions

when work is to be carried out on the network or parts of it which necessitates the provision of Safety Precautions on High Voltage Equipment pursuant of this section of the Grid Code. A Safety Co-ordinator may be responsible for the co-ordination of safety at more than one Connection Point of the network.

Each Safety Co-ordinator shall be authorised by the TSP or a User, as the case may be, as competent to carry out the functions set out to achieve Safety from the Network at all times.

Only authorised person at the TSP and the User(s) will carry out Safety activities at all times.

Contact between Safety Co-ordinators at TSP and User(s) will be made via normal operational channels, and accordingly separate telephone numbers for Safety Co-ordinators need be registered and available at TSP and Users at all times.

If work is to be carried out on the network which necessitates the provision of Safety Precautions, in accordance with the provisions of this Section, the requesting Safety Co-ordinator who requires Safety Precautions to be provided shall contact the relevant implementing Safety Co-ordinator to co-ordinate the establishment of Safety Precautions throughout the work.

12.5. RECORD OF NETWORK SAFETY PRECAUTIONS (RNSP)

12.5.1. The TSP and Users will use the format of the RNSP forms set out in Appendix 4A, and 4B of this Code. That set out in Appendix 4A and designated as “RNSP-R”, shall be used when the TSP is requesting Safety Co-ordinator, and that in Appendix 4B designated as “RNSP-I” when the TSP is implementing Safety Co-ordinator. Proformas of RNSP-R and RNSP-I must be provided by the TSP and Users for use at all times when Safety Precaution is required.

12.5.2. All references to RNSP-R and RNSP-I shall be taken as referring to the corresponding parts of the alternative forms or other tangible written records agreed between the TSP and the User.

12.5.3. RNSP-R will have an identifying number written or printed on it, comprising a prefix which identifies the location at which it is issued, and a unique serial number consisting of four digits and suffix “R” for the TSP and the User.

12.5.4. Each User shall apply to the TSP for approval of its proposed prefix

12.5.5. The TSP shall consider the proposed prefix to see if it is the same as a prefix used by the TSP or another User or not confusing. The TSP shall respond in writing within ten days of its decision on the prefix to the User.

12.5.6. If the TSP disapproves, it shall explain in its response why it has disapproved and will suggest an alternative prefix. In this situation, the User shall either notify the TSP in writing of its acceptance of the suggested alternative prefix or it shall apply in writing to the TSP with its revised prefix proposal and the above procedure shall apply.

12.6. SAFETY PRECAUTIONS ON HIGH VOLTAGE EQUIPMENT

12.6.1. Safety Precautions

For the purpose of co-ordination of safety relating to High Voltage equipment, the term “Safety Precautions” means Isolation and /or Earthing.

12.6.2. Agreement of Safety Precautions

The Safety Co-ordinator requesting Safety Precautions on another Equipment or parts of the Transmission Network will contact the relevant implementing Safety Co-ordinator(s) to agree the location of the Safety Precautions to be established. This agreement will be recorded in the respective Safety Logs.

It is the responsibility of the implementing Safety Co-ordinator to ensure that adequate Safety Precautions are established and maintained, on his and/or another Equipment connected to his equipment, to enable Safety from the Equipment to be achieved on the High voltage Equipment, specified by the requesting Safety Co-ordinator which is to be identified in RNSP.

When the implementing Safety Co-ordinator is of the reasonable opinion that it is necessary for Safety Precautions on the System of the requesting Safety Co-ordinator, other than on the High Voltage Equipment specified by the requesting Safety Co-ordinator, which is to be identified in RNSP, he shall contact the requesting Safety Co-ordinator and the details shall be recorded in the RNSP forms. It is the responsibility of the requesting Safety Co-ordinator to establish and maintain such Safety Precautions.

In the event where the requesting Safety Co-ordinator and the implementing Safety Co-ordinator are unable to agree the location of the isolation and (if requested) Earthing, both shall be at the closest available points on the infeeds to the High Voltage equipment on which Safety from the network is to be achieved as indicated on the operating diagram.

12.6.3. Implementation of Isolation

Following the agreement of the Safety Precautions in accordance with 13.6.2 the implementing Safety Co-ordinator shall then establish the agreed Isolation.

The implementing Safety Co-ordinator shall conform to the requesting Safety Co-ordinator that the agreed Isolation has been established, and identify the requesting Safety Co-ordinator’s High Voltage Equipment up to the Connection Point, for which the Isolation has been provided. The confirmation shall specify:

- (a) For each location, the identity (by means of High Voltage Equipment, name, nomenclature and numbering or position as applicable) of each point of Isolation, whether Isolation has been achieved by an isolating Device in the isolating position or by an adequate physical separation;
- (b) Where an Isolated Device has been used whether the isolating position is either:

- (i) Maintained by immobilising and Locking the Isolating Device in the isolating position and affixing a Caution Notice to it. Where the Isolating Device has been Locked with a Safety Key that the Safety Key has been secured in a Key Safe and the Key Safe will be retained in a safe custody;
- (c) Where an adequate physical separation has been used that will be in accordance with, and maintained by the method set out in the Local Safety Instructions of TCN or that of the User, as the case may be, and, if it is part of that method, that a Caution Notice be placed at the point of separation.
- (d) The conformation of Isolation shall be recorded in the respective Safety Logs.

12.6.4. Implementation of Earthing

The Safety Co-ordinator shall confirm to the Requesting Safety Co-ordinator that the agreed Earthing has been established, and identify the Requesting Safety Co-ordinator's HV equipment for which earthing has been provided. The conformation shall specify:

- (a) For each location, the identity (by means of HV Equipment name, nomenclature and numbering or position, as is applicable) of each point of Earthing; and
- (b) In respect of the Earthing Device used, whether it is:
 - (i) Immobilised and Locked in the earthing position. Where the Earthing Device has been Locked with a Safety Key, that the Safety Key has been secured in a Key Safe and the Key Safe will be retained in safe custody; or
 - (ii) Maintained and/or secured in position by such other method which is in accordance with the Local Safety Instruction of the TSP or that User, as the case may be.

The confirmation of Earthing shall be recorded in the respective Safety Logs.

The Implementing Safety Co-ordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting safety Co-ordinator.

12.6.5. Procedure for Issuing RNSP

Where Safety Precautions on another Equipment are being provided to enable work on the Requesting Safety Co-ordinator's Equipment, before any work commences they must be recorded by the RNSP being issued. The RNSP is applicable to High Voltage Equipment up to the Connection Point identified in the RNSP-R and RNSP-1 forms.

Where Safety Precautions are being provided to enable work to be carried out on both sides of the Connection Point an RNSP will need to be issued for each side of the Connection Point with the TSP and the respective User each enacting the role of requesting Safety Co-ordinator. This will result in an RNSP-R and RNSP-I form being completed by each of the TSP and the User, with each Safety Co-ordinator issuing on RNSP number.

Once the Safety Precautions have been established, the Implementing Safety Co-ordinator shall complete form RNSP-I recording the details specified in 12.6.2, 12.6.3 and 13.6.4.

The Requesting Safety Co-ordinator shall complete form RNSP-R, making a precise copy of the details received. On completion, the Requesting Safety Co-ordinator shall read the entries made back to the sender and check that an accurate copy has been made.

The Requesting Safety Co-ordinator shall then issue the number of the RNSP taken from the RNSP-R, to the Implementing Safety Co-ordinator who will ensure that the number, including the prefix and suffix, is accurately recorded in the designated space on the RNSP-I form.

The Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator shall complete and sign appropriate parts of the RNSP-R and RNSP-I forms respectively and then enter the time and date. When signed no alteration to the RNSP is permitted; the RNSP may only be cancelled.

The Requesting Safety Co-ordinator is then free to authorise work (including a test that does not affect the Implementing Safety Co-ordinator's equipment) Where testing is to be carried out which affects the Implementing Safety Co-ordinator's equipment, the procedure set out in 13.6.7 shall be implemented.

12.6.6. RNSP Cancellation Procedure

When the Requesting Safety Co-ordinator decides that Safety Precautions are no longer required, he will contact the relevant Implementing Safety Co-ordinator to effect cancellation of the associated RNSP.

The Requesting Safety Co-ordinator will inform the relevant Implementing Safety Co-ordinator of the RNSP identifying number (including the prefix and suffix), and agree it is the RNSP to be cancelled.

The Requesting Safety Co-ordinator and the relevant Implementing Safety Co-ordinator shall then respectively complete form RNSP-R and RNSP-I forms with their names and contact address and shall then exchange details. On exchange of details the respective RNSP is cancelled.

Neither Safety Co-ordinator shall instruct the removal of any Isolation forming part of the Safety Precautions as part of the returning of the High Voltage equipment to service until it is committed to each by each other that every earth on each side of the Connection Point, within the points of isolation identified on the RNSP, has been removed or disconnected by the provision of additional Points of Isolation.

Subject to provisions in this Condition the Implementing Safety Co-ordinator is then free to arrange the removal of the safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Co-ordinator is representing. Nothing in this Code prevents the TSP and Users agreeing to a simultaneous cancellation and issue a new RNSP, if both agree.

12.6.7. Testing Affecting Another Safety Co-ordinator's Equipment

The carrying out of test may affect Safety Precautions on RNSPs or work being carried out which does not require a RNSP. Testing can, for example include the application of an independent test voltage. Accordingly, where the Requesting Safety Co-ordinator wishes to authorise the carrying out of such a test to which the procedures in this section of the Grid Code apply he may not do so and the test will not take place unless the steps in (a) to (c) below have been followed and confirmation of completion has been recorded in the respective Safety Logs:

- (a) Confirmation must be obtained from the Implementing Safety Co-ordinator that:
 - (i) no person is working on, or testing, or has been authorised to work on, or test, any part of its equipment or another equipment (other than the equipment of the Requesting Safety Co-ordinator) within the points of Isolation identified on the RNSP form relating to the test which is proposed to be undertaken, and
 - (ii) no person will be so authorised until the proposed test has been completed (or cancelled) and the Requesting Safety Co-ordinator has notified the Implementing Safety Co-ordinator of its completion (or cancellation);
- (b) Any other current RNSP which relate to the parts of the equipment in which the testing is to take place must have been cancelled in accordance with procedures set out in 13.6.6
- (c) The Implementing Safety Co-ordinator must agree with the Requesting Safety Co-ordinator to permit the testing on that part of the equipment between the points of Isolation identified in the RNSP associated with the test and the points of Isolation on the Requesting Safety Co-ordinator's equipment.
- (d) The Requesting Safety Co-ordinator will inform the Implementing Safety Co-ordinator as soon as the test has been completed or cancelled and the confirmation shall be recorded in the respective Safety Logs.
- (e) When the test gives rise to the removal of Earthing which it is not intended to re-apply, the relevant RNSP associated with the test shall be cancelled at the completion or cancellation of the test in accordance with the procedure set out in either 13.6.5 or 13.6.6. Where the Earthing is re-applied following the completion or cancellation of the test, there is no requirement to cancel the relevant RNSP associated with the test pursuant to this Condition.

12.6.8. Emergency Situations

There may be circumstances where Safety Precautions need to be established in relation to an unintended electrical connection or situations where there is an unintended risk of electrical connection between the Transmission Network and a User's Equipment, for example resulting from an incident where one line becomes attached or unacceptably close to another.

In those circumstances, if both the TSP and the respective User agree, the relevant provisions of 12.6.5 will apply as if the electrical connections or potential connections were, solely for the purposes of this Section, a Connection Point.

The relevant Safety Co-ordinator shall be that for the electrically closest existing Connection Point to that User's equipment or such other local Connection Point as may

be agreed between the TSP and the User, with discussions taking place between the relevant local Safety Co-ordinators. The Connection Point to be used shall be known in this Condition as the "relevant Connection Point".

- (a) The Local Safety Instructions shall be those which apply to the relevant Connection Point.
- (b) The prefix for the RISSP will be that which applies for the relevant Connection Point.

12.6.9. Loss of Integrity of Safety Precautions

In any instance when any Safety Precautions may be ineffective for any reason the relevant Safety Co-ordinator shall inform the other Safety Co-ordinator(s) without delay of that being the case and, if requested, of the reasons why.

12.6.10. Safety Log

The TSP and Users shall maintain Safety Logs which shall be a chronological record of all messages relating to Safety Co-ordination under this code sent and received by the Safety Co-ordinator(s). The Safety Logs must be retained for a period of not less than one year.

