



**ECA**

ECONOMIC  
CONSULTING  
ASSOCIATES

**Assessing the Key Elements for the  
Development of a Third Party Access  
Code in Papua New Guinea**

**Final Draft PNG Grid Code (Task 6C)**

**May 2014**

**Submitted to the World Bank and the  
Independent Consumer and Competition  
Commission by**

**Economic Consulting Associates**

Economic Consulting Associates Limited  
41 Lonsdale Road, London NW6 6RA, UK  
tel: +44 20 7604 4545, fax: +44 20 7604 4547  
<http://www.eca-uk.com>

## Contents

<b>Contents</b>	<b>i</b>
<b>Abbreviations and Acronyms</b>	<b>iv</b>
<b>1 INTRODUCTION</b>	<b>1</b>
<b>2 COMMENTS ON THE DRAFT GRID CODE</b>	<b>3</b>
2.1 General Comments	3
2.2 Comments from PPL	3
2.3 Written Comments from ICCC	3
2.4 Comments from IPP	3
2.5 Comments from World Bank	4
<b>3 DRAFT GRID CODE</b>	<b>5</b>
<b>1. General Conditions</b>	<b>5</b>
<b>1.1 Definitions</b>	<b>5</b>
<b>1.2 Interpretation</b>	<b>20</b>
<b>1.3 Scope and Coverage</b>	<b>20</b>
<b>1.4 Objectives</b>	<b>21</b>
<b>2. Technical and Performance Standards</b>	<b>22</b>
<b>2.1 Safety Standards</b>	<b>22</b>
<b>2.2 Power Quality Standards</b>	<b>22</b>
<b>2.3 Reliability Standards</b>	<b>24</b>
<b>2.4 System Loss Standards</b>	<b>26</b>
<b>2.5 Protection Standards</b>	<b>26</b>
<b>2.6 Grounding Requirements</b>	<b>27</b>
<b>2.7 Equipment Standards</b>	<b>27</b>
<b>2.8 Maintenance Standards</b>	<b>27</b>
<b>2.9 Environmental and Social Safeguard Standards</b>	<b>28</b>
<b>2.10 Compliance and Performance Monitoring and Assessment</b>	<b>28</b>

---

<b>3.</b>	<b>Transmission Network Connection</b>	<b>28</b>
<b>3.1</b>	<b>Transmission Connection Service Procedure</b>	<b>28</b>
<b>3.2</b>	<b>Fixed Asset Boundary Document</b>	<b>32</b>
<b>3.3</b>	<b>Electrical Diagrams and Connection Point Drawings</b>	<b>34</b>
<b>3.4</b>	<b>Site and Equipment Identification and Labelling</b>	<b>36</b>
<b>3.5</b>	<b>Data Registration</b>	<b>36</b>
<b>3.6</b>	<b>Connection Point</b>	<b>38</b>
<b>3.7</b>	<b>Protection System at Connection Point</b>	<b>39</b>
<b>3.8</b>	<b>SCADA and Communication System Requirements</b>	<b>40</b>
<b>3.9</b>	<b>Metering Requirements</b>	<b>40</b>
<b>3.10</b>	<b>Connection Conditions for Power Producers</b>	<b>42</b>
<b>3.11</b>	<b>Connection Conditions for Users other than Power Producers</b>	<b>46</b>
<b>4.</b>	<b>Power Development Planning</b>	<b>47</b>
<b>4.1</b>	<b>Power Development Plan</b>	<b>47</b>
<b>4.2</b>	<b>Planning Responsibilities</b>	<b>50</b>
<b>4.3</b>	<b>Planning Criteria</b>	<b>52</b>
<b>4.4</b>	<b>Power Development Planning Procedures</b>	<b>55</b>
<b>4.5</b>	<b>Power Development Planning Data</b>	<b>56</b>
<b>4.6</b>	<b>Power System Analysis</b>	<b>58</b>
<b>5.</b>	<b>Power System Operation</b>	<b>60</b>
<b>5.1</b>	<b>Operating States and Criteria</b>	<b>60</b>
<b>5.2</b>	<b>Operational Responsibilities</b>	<b>61</b>
<b>5.3</b>	<b>System Operation Notices and Reports</b>	<b>63</b>
<b>5.4</b>	<b>Operational Planning</b>	<b>64</b>
<b>5.5</b>	<b>Frequency and Voltage Control</b>	<b>68</b>
<b>5.6</b>	<b>Ancillary Services</b>	<b>70</b>

---

<b>5.7</b>	<b>Scheduling and Dispatch</b>	<b>72</b>
<b>5.8</b>	<b>Emergency Procedures</b>	<b>78</b>
<b>5.9</b>	<b>Safety Coordination</b>	<b>80</b>
<b>6.</b>	<b>Implementation and Enforcement</b>	<b>83</b>
<b>6.1</b>	<b>Governance of the Grid Code</b>	<b>83</b>
<b>6.2</b>	<b>Compliance to the Grid Code</b>	<b>84</b>
<b>6.3</b>	<b>Dispute Resolution</b>	<b>86</b>
	<b>ANNEXES</b>	<b>90</b>
	<b>Annex 1: Protection Requirements</b>	<b>91</b>
	<b>A1.1 Generator Protection</b>	<b>91</b>
	<b>A1.2 Transmission Line Protection</b>	<b>91</b>
	<b>A1.3 Transformer Protection</b>	<b>92</b>
	<b>A1.4 Bus Protection</b>	<b>92</b>
	<b>A1.5 Distribution Feeder Protection</b>	<b>92</b>
	<b>Annex 2: Planning Data</b>	<b>94</b>
	<b>A2.1 Standard Planning Data</b>	<b>94</b>
	<b>A2.2 Detailed Planning Data</b>	<b>96</b>

## **APPENDICES**

Appendix A – Comments from ICCC Technical Consultant

Appendix B – Comments from PPL

Appendix C – Comments from IPP

Appendix D – Comments from World Bank Power System Expert

Appendix E - Comments from World Bank Environmental and Social Safeguard Expert

Appendix F - Comments from World Bank Senior Economist

---

## **Abbreviations and Acronyms**

DPE	Department of Petroleum and Energy
ECA	Economic Consulting Associates
EMC	Electricity Management Committee
ERC	Electricity Regulatory Contract
ICCC	Independent Consumer and Competition Commission
IPP	Independent Power Producer
PNG	Papua New Guinea
PPA	Power Purchase Agreement
PPL	PNG Power Ltd
TNO	Transmission Network Owner
TPA	Third Party Access

## 1 INTRODUCTION

This report is submitted under Task 6 of the project “Assessing the Key Elements for the Development of a third party access code for the Transmission and Distribution Networks in Papua New Guinea” to implement the Third Party Access Code (TPA) Code. The project is being undertaken by Economic Consulting Associates (ECA) for the Independent Consumer and Competition Commission (ICCC) of Papua New Guinea (PNG) under World Bank financing.

Task 6 covers the extension of the original scope of work to include the drafting of a set of technical rules or Grid Code to accompany the TPA Code. The need for such a set of rules was identified during the initial review undertaken for the TPA Code.

The Grid Code was developed under the following steps:

- (i) Initial data collection on existing standards, procedures and requirements applied in PNG through questionnaires and an inception visit.
- (ii) Preparation of an initial draft of the Grid Code based on the responses received to the questionnaires and drawing on international practice where no existing standards, procedures or requirements exist.
- (iii) Consultation on the initial draft through written comments and a stakeholder workshop.
- (iv) Preparation of a final draft of the Grid Code, responding to the comments received in the consultation process.
- (v) Capacity building for the implementation of the Grid Code.

This report contains the final draft of the Grid Code which incorporated the comments received by ECA from ICCC, PPL, IPP and WB and the discussions during the stakeholder workshops in 29 April to 1 May 2014. The Workshops was conducted for capacity building aimed at understanding the code and its implications for implementation. The discussions provided an opportunity for the stakeholder to clarify the provisions of the code and to give their comments and suggestions. .

This draft Grid Code covers:

- o General Conditions for its interpretation and implementation
- o Technical and Performance standards for the Grid covering safety, power quality, reliability, system loss, protection, grounding, equipment, and maintenance.

- o Rules, procedures and requirements for application, review and approval of transmission connections.
- o Rules, procedures and requirements for preparing, review and approval of power development plan.
- o Rules, procedures and requirements for System Operation including operational planning, frequency and voltage control, ancillary services, scheduling and dispatch, emergency, and safety coordination.
- o Implementation and Enforcement procedures

The governance and dispute resolution procedures for the draft Grid Code follow those in the final draft TPA Code, which have been reviewed and agreed by ICCC. As drafted, this Grid Code would be overseen by ICCC, as the regulator for the electricity. The technical aspects of regulation are designated to the Department of Petroleum and Energy (DPE). Thus, the Grid Code was drafted using the term *Regulator* to refer to the ICCC and *Technical Regulator* to refer to the DPE.

## **2 COMMENTS ON THE DRAFT GRID CODE**

### **2.1 General Comments**

ECA received both written comments and comments or suggestions raised during the visits of Consultants in PNG. In general, the comments seek clarification or suggest to provide more specific information that will enhance the understanding and implementation of the Grid Code. In response to the comments, many sections have been revised, expanded and added. Section 1.1 (Definitions) of the Grid Code was expanded to define terms used in the Code.

### **2.2 Comments from ICCC**

The ICCC sent comments from its external technical consultant (Gravelroad) tasked to review the Draft Grid Code. The consultant comments are included in Appendix A. Many of the suggestions were adopted in the final draft of the Grid Code. However, there are suggestions that were not adopted such as those requiring very detailed procedures and requirements which are appropriate to be included in the Operating Procedures which the Transmission Network Owners shall include in their submission of Compliance Plan to the Regulator (Chapter 6 of Grid Code). There were also concerns on prescribing standards that may not be complied with by power companies including PPL so it was recommended to consider the existing situations in PNG. In this regard, the Consultant has discussed with PPL the feasibility of the proposed standards and requirements. It must also be emphasized that the Grid Code intends to upgrade the performance of the power system in PNG and that the implementation of the Grid Code will be phased with transitional program such as Phase 1 (within 1 year), Phase 2 (within 5 years) and Phase 3 (within 10 years). These are detailed in Chapter 6 which the submission of the Transmission Network Owner of its Statement of Compliance and Compliance Plan.

### **2.3 Comments from PPL**

The development of the Grid Code was intentionally designed to be capture the practices of PPL with the objective of upgrading the practices and modernize the power system in PMG up to standards of comparable developing countries practicing international best practices. The Grid Code was therefore written with the active participation of relevant departments of PPL. Thus, comments from PPL were raised during the meetings and were addressed in this final draft of the PNG Grid Code. A copy of marked-up Draft Grid Code with comments from PPL is included in Appendix B

### **2.4 Comments from IPP**

The IPP in PNG (Daewoo/Mr. Y.H. Kim) also sent written comments to clarify the requirements of the Grid Code for Power Producers. The suggestions of the IPP



were adopted since these will enhance the clarity of the Code. The Draft Grid Code with mark-up comments from the IPP is included in Appendix C.

## **2.5 Comments from World Bank**

World Bank comments came from its Power System Expert (Mr. Sev Maso), Environmental, Social Safeguard Expert (Asger Christensen) and Senior Economist (Ms. Natsuko Toba). Their comments are included in marked-up Draft Grid Code in Appendix D to F, respectively.

The comments of the Power System Expert were all clarificatory and were all adopted except for proposed edits that are not consistent to the intent of the Code. For example, the requirements for Power Producers were proposed to be written as the requirements for “Third Party Power Producers”. This suggestion was rejected because the Regulated Retailer is also a Power Producer who own and operate power plants that must also comply with the Grid Code. Overall, the comments from Mr. Sev Maso have been very useful in finalizing the Draft Grid Code.

Comments of the Environmental and Social Safeguard Expert to include general statements on environmental and social safeguards in the Power Development Planning were adopted. We also included a section on Environmental and Social Safeguard Standards in Chapter 2 of the Draft Grid Code which prescribed the Technical and Performance Standards.

### 3 DRAFT GRID CODE

#### 1. General Conditions

---

##### 1.1 Definitions

**Accountable Manager** means a person who has been duly authorized by the Transmission Network Owner (or a User of Transmission Network) to sign the Fixed Asset Boundary Documents on behalf of the Transmission Network Owner (or the User of Transmission Network) that binds the Transmission Network Owner (or User of Transmission Network) to the obligations under the Connection Agreement in accordance with this code;

**Active Energy** means the integral of Active Power with respect to time, measured in Watt-hours (Wh) or multiples thereof (kWh, MWh or GWh).

**Active Power** means the time average of the instantaneous power over one period of the electrical wave, measured in Watts (W) or multiples thereof (kW or MW). For AC circuits or Systems, it is the product of the root-mean-square (RMS) or effective value of the voltage and the RMS value of the in-phase component of the current. In a three-phase system, it is the sum of the Active Power of the individual phases;

**Alert State** means an operating state of the Transmission Network when at least one of the following conditions exist: (1) the Contingency Reserve is insufficient; (2) voltages at Connection Points are outside  $\pm 5\%$  but within  $\pm 10\%$  of nominal; (3) a weather disturbance has entered the PNG area of responsibility, which may affect power system operations; and/or (4) civil unrest or law and order problems exist which may pose a threat to power system operations;

**Amended Connection Agreement** means an agreement between the Transmission Network Owner a User that specifies the terms and conditions pertaining to the modifications of the User System or Equipment at an existing Connection Point in the Transmission Network;

**Ancillary Service** means the support services such as Frequency Regulating, Contingency Reserves (including Spinning Reserve and Backup Reserve), Reactive Power support, and Black Start which that are essential in maintaining Power Quality, Reliability and Security of the Grid;

**Ancillary Service Agreement** means an agreement between the Transmission Network Owner and a Power Producer that specifies the terms and conditions pertaining to the provision of Ancillary Services by the Power Producer;

**Ancillary Service Schedule** means a schedule that specifies which Generating Units will provide which type of Ancillary Service and when the Ancillary Service will be provided;

**Automatic Generation Control (AGC)** means the regulation of the power output of Generating Units in response to a change in system Frequency so as to maintain within the predetermined limits the system frequency;

**Automatic Under Frequency Load Shedding (AUFLS)** means the process of automatically and deliberately removing pre-selected loads from the Transmission Network in response to an abnormal condition in order to maintain the integrity of the Grid;

**Average System Interruption Duration Index (ASIDI)** means the average duration of interruptions of Users of the Transmission Network in a given period. It is computed by multiplying the load kVA (or kW) per Interruption with the Interruption

Duration, adding the products over all Interruptions, and dividing the sum by the total connected load kVA (or kW);

**Average System Interruption Frequency Index (ASIFI)** means the average number of times that Users of the Transmission Network is interrupted in a given period. It is computed by adding the load kVA (or kW) per Interruption over all Interruptions, and dividing the sum by the total connected load kVA (or kW);

**Backup Reserve** means the capacity of Generating Units that has ability to respond to a re-dispatch performed by the System Operator after an unplanned outage of a Generating Unit(s) after the Spinning Reserve has taken the load of the Generating Unit(s) on unplanned outage;

**Black Start** means the process of recovery from Total System Blackout using Generating Unit(s) with the capability to start and synchronize with the Grid without an external (or off-site) power supply;

**Black Start Capability** means the ability of a Generating Unit to perform Black Start, i.e., go from a shutdown condition to an operating condition and start delivering power to the Grid without external power supply.

**Blackout** means the loss of electrical service over a significant area that may last from a few minutes to several weeks, depending on the cause

**Blue Alert** means a notice issued by the System Operator when weather disturbance has entered the PNG area of responsibility which may affect the power system operation;

**Business Day** means any day on which banks are open for business;

**Capability and Availability Declaration** means the data submitted by the Power Producer for its Generating Units, which is used by the System Operator in preparing the Generation Schedule.

**Capacity Margin** means the difference between the available generation capacity in a period and the forecast demand in that period;

**Certificate of Approval to Connect** means a document issued by the Transmission Network Owner certifying the approval on the proposed Connection of the applicant User

**Committed Distribution Project** means the distribution project of the Regulated Retailer in the first five (5) years of the Distribution Development Plan that has been approved by the Regulator;

**Committed Power Generation Project** means the power plant project that has firm schedule of construction as evidenced by the available project financing and has been approved by the Regulator being part of the least-cost Power Development Plan;

**Committed Transmission Project** means the transmission project of the Transmission Network Owner in the first five (5) years of the Transmission Development Plan that has been approved by the Regulator;

**Committed Project Data** means the data pertaining to a User System once the offer for a Connection Agreement or an Amended Connection Agreement is accepted;

**Compliance Plan** means the plan prepared by the Transmission Network Owner, Power Producers, Regulated Retailers and Large Customers detailing the projects and activities that they will implement to ensure the compliance of their electrical systems and Equipment, operating procedures, and management systems with the technical and performance standards of the Grid Code;

**Component** means an equipment, line, transformer, generating unit or circuit, a section of a line or circuit, or a group of items, which are viewed as one unit for a specific purpose.

**Connected Project Data** means the data which replaces the estimated values in the Preliminary Project Data and Committed Project Data that were assumed for evaluating proposed connection and for planning purposes, with validated actual values and updated estimates for the future and by updated forecasts, in the case of forecast data.

**Connection Agreement** means an agreement between the Transmission Network Owner and a User that specifies the terms and conditions pertaining to the connection of the User System or Equipment to a Connection Point in the Transmission Network;

**Connection Completion Date** means the date, specified in the Connection Agreement or Amended Connection Agreement, when the User System is scheduled to be completed and be ready for connection to the Transmission Network;

**Connection Point** refers to the point of connection (or common coupling) of the User System to the Transmission Network. For purposes of clarity, the Connection Point is the switching station where the circuit breaker is installed and which shall be used for the connection or disconnection of a User System. It may be at the substation of the Transmission Network Owner or at the substation of the User;

**Constrained Generation Schedule** means the Generation Schedule prepared by the System Operator for dispatching of Generating Units that considers the operational constraints of the Transmission Network to deliver power.

**Contingency Reserve** means the generating capacity from Generating Units allocated to cover loss of generation from a synchronized Generating Unit including Spinning Reserve and Backup Reserve;

**Customer** means a User that is supplied with (or drawing) electrical energy through the Transmission Network or Distribution Network;

**Day-Ahead Demand Forecast** means a 24 hourly Demand Forecast prepared by the System Operator for the next Operating Day as part of the Operational Plan;

**Day-Ahead Generation Schedule** means a 24 hourly Generation Schedule of the Operational Plan prepared and issued by the System Operator to meet the Day-Ahead Demand Forecast for the next Operating Day;

**Day-Ahead Operational Plan** means an Operational Plan for the next Operating Day prepared by the System Operator containing Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule;

**Day-Ahead Outage Plan** means the schedule containing the outages of power plant or Generating Units for the next Operating Day;

**Dead Bus** means an inactive bus; a point on the Transmission Network where electric energy is not available for transmission;

**Dead Bus Access Capability** means the Capability of power plant to access a Dead Bus in order to energize and make electric energy available for transmission;

**Degradation of the Grid** refers to a condition resulting from a User System connection or a Transmission expansion project that has a Material Effect on the Grid or the System of other Users and which can be verified through Grid Impact Studies;

**Demand** the Active Power and/or Reactive Power required by a Load by the power system at a particular time; It may also refer to the required Active Energy and/or Reactive Energy required by a Load or by the power system;

**Demand Control** means the reduction in demand for the control of the Frequency when the Grid is in an Emergency State. This includes Automatic Load Shedding, Manual Load Shedding, Voluntary Load Curtailment, and Embedded Generation of Users;

**Demand Forecast** means the projected or forecasted Active Power and/or Active Energy of a User at a Connection Point or the entire power system for a given period (short-term, medium-term or long-term) used for power development planning or operational planning;

**Detailed Planning Data** means the additional data required by the Transmission Network Owner or Technical Regulator to capture the dynamic characteristics of the power system for the conduct of a more accurate Grid Impact Studies and/or Power Development Planning studies;

**Dispatch** means the process of allocating the total Demand of the Grid through the issuance of Dispatch Instructions for the Generating Units to generate electricity to meet the Demand and for the Generating Units providing Ancillary Services in order to achieve the operational requirements of balancing demand with generation that will ensure the Security of the Grid.

**Dispatch Instruction** means the instruction issued by the System Operator in real time to the Power Producers with Generating Units to generate electricity and/or to provide Ancillary Services;

**Dispatch Parameters** means the technical data pertaining to the Generating Units, which are taken into account in the preparation of the Generation Schedule;

**Distribution Development Plan** means the plan prepared by Regulated Retailer detailing the forecasts for the peak demand and energy, the projects to expand, reinforce and rehabilitate the Distribution Network within its franchised area to serve its retail customers.

**Distribution Development Project** means a project for the expansion, reinforcement and rehabilitation of the Distribution Network identified in the Distribution Development Plan of the Distribution Network Owner;

**Distribution Network** refers to the whole or part of a medium voltage or low voltage power system, which is connected to a transmission network or directly to power plants, used by a Licensed Retailer for the distribution of electricity, but does not include any part of a transmission network and/or the power plants;

**Earth Fault Factor** means the ratio of the highest root-mean-square (RMS) value of the phase-to-ground power system Frequency voltage on a sound phase, at a selected location, during a fault to ground affecting one or more phases, to the RMS value of the phase-to-ground power frequency voltage that would be obtained for the same location without the fault;

**Economic Dispatch** means the process of scheduling Generating Units facilities and issuing Dispatch Instructions to Power Producers, considering the energy demand, operating reserve requirements, power supply contracts, fuel costs, security constraints, outages, and other contingency plans to achieve economic (least-cost) operation while maintaining the Power Quality, Reliability and Security of the Grid prescribed by this code;

**Economic Loading Range** means the range of loads over which a particular size and type of Equipment (for example, a line or transformer) is the least-cost choice or option;

**Economic Load Reach** means the least-cost maximum distance over which a particular type and size of line can reach without violating the power quality standards considering the power to be delivered by the line;

**Electrical Diagram and Connection Point Drawings** means the diagrams and drawings that shows through schematic representation shows the connection and

layout of Equipment or Power System Components to each other or to external circuits and using standard electrical symbols and Equipment Identification;

**Electricity Regulatory Contract** refers to contract of regulated entities issued by the Regulator (ICCC) which specifies the prices and conditions including service standards for the electricity supply and services to the regulated entity's consumers;

**Embedded Generation** means the generation of electricity by the customers using their own generating facilities such as standby Generating Units to reduce the demand of the Grid to manage generation deficiencies;

**Emergency Drill** means the drill that simulates emergency situations to familiarize all personnel with the emergency and restoration procedures.

**Emergency State** means an operating condition when any of the following conditions exist: (a) generation deficiency; (b) Multiple Outage Contingency; (c) transmission network voltages are outside the limits of 0.90 and 1.10; or (d) the loading level of any transmission line or substation equipment is above 110 percent of its continuous rating;

**Energy Management System (EMS)** means computer-aided tools used by the System Operator to monitor, control and manage the economic and secured operation of the Grid in real-time;

**Energy Margin** means the difference between the available energy from all the Generating Units and forecast energy demand during the same period;

**Equipment** means all apparatus, machines, conductors, and related devices used as a part of or in connection with an electrical installation;

**Site and Equipment Identification** means the system of numbering or nomenclature for the identification of the site and Equipment in the Transmission Network and the Connection Points of the User System;

**Energy** means Active Energy, unless otherwise qualified;

**Energy Management Committee** refers to the committee of high level government officials of PNG designated as the policy making and coordination body for the electrification and development of the power industry in PNG under the Electricity Industry Policy of 2011;

**Energy Margin** means the difference between the available energy from all the Generating Units and the forecast energy demand during the same period of time;

**Estimated Equipment Data** the best estimates of data such as typical values of ratings and parameters of Equipment pertaining to a User Development submitted by the User applying for connection to the Transmission Network;

**Expected Unserved Energy (EUE)** means the expected energy curtailment within the specified period of time due to deficiency in generation capacity and outages of Generating Units;

**Fast Start Capability** means the capability of a Generating Unit or Generating Plant to start and synchronize with the Grid within 15 minutes;

**Fault Clearance Time** means the time interval from fault inception until the end of the arc extinction by the circuit breaker including the action of protective and control relays.

**Fault Level** means the expected current that will flow into a short circuit or earth-fault at a specified point in the Grid.

**Fault Withstand Time** means the the amount of time that an Equipment or Component must withstand a given Fault Level without being damaged or destroyed;

**Five-Year Statement of the Distribution Development Plan** means the part of the Distribution Development Plan which contain Committed Distribution Projects in the first five (5) years of the planning horizon;

**Five-Year Statement of the Transmission Development Plan** means the part of the Transmission Development Plan which contain Committed Transmission Projects in the first five (5) years of the planning horizon;

**Fixed Asset Boundary Document** means a document containing information and which defines the operational responsibilities for the equipment at the Connection Point of a User to the Transmission Network;

**Frequency** means the number of complete cycles of a sinusoidal current or voltage of the Grid per unit of time measured in cycles per second or Hertz;

**Frequency Control** means a strategy used by the System Operator to maintain the Frequency of the Grid within the limits prescribed by the Grid Code through the timely use of Frequency Regulating Reserve, Contingency Reserve, and Demand Control;

**Frequency Regulating Reserve** means the one or more Generating Units that assists in Frequency Control by providing automatic Primary and Secondary Frequency response;

**Frequency Variation** means the deviation of the fundamental Power System Frequency from its nominal value of 50 Hz;

**Generation Schedule** means the schedule of target loading levels or production of each Generating Unit prepared by the System Operator for each Operating Hour of given operating period through Economic Dispatch procedures;

**Generation Scheduling and Dispatch Parameters** means the technical data pertaining to the Generating Units taken into account by the System Operator in the preparation of the Generation Schedule;

**Generating Unit** means the conversion apparatus in a power plant including auxiliaries and associated equipment, functioning as a single unit is used to convert some form of energy into electrical energy for generation of electricity or to perform other functions such as Ancillary Services.

**Good Industry Practice** means the practices and methods not specified in specific standards but are generally accepted by the power industry to be sound and which ensure the safe and reliable planning, operation, and maintenance of electric Power System.

**Grid** means the the power system including the Transmission Network operated and controlled by the Transmission Network Owner and the User Systems (power plants and customer substations) connected to the Transmission Network;

**Grid Code** refers to the set of rules, requirements, procedures, and standards to ensure the safe, reliable, secured and efficient operation, maintenance, and development of the Grid and its associated facilities;

**Grid Impact Study** means a set of technical study to determine the (i) impact of the proposed connection of a User to the Transmission Network and to other User Systems, and (ii) the necessary augmentations to or reinforcements of Transmission Network to ensure that the Grid will operate within the performance standards prescribed by this code;

**Grid Outage Plan** means a plan containing the outage schedules of Generating Units, User System and Transmission Network coordinated by the System Operator and specifying the details of the planned outage of Equipment in the Transmission Network or in any Power Plant or any User System;

**Grounding** means a conducting connection by which an electrical circuit or Equipment is connected to earth or to some conducting body of relatively large extent that serves as ground.

**IEC Standard** means the international standard for Equipment approved and published by the International Electro-technical Commission (IEC);

**Implementing Safety Coordinator** means the Safety Coordinator assigned by the Transmission Network Owner (or the User) to implement or establish the requested Safety Precautions in the User System (or the Transmission Network);

**Indicative Distribution Project** means a proposed distribution project of the Regulated Retailer beyond the first five (5) years of the Distribution Development Plan which the Regulator has not approved yet;

**Indicative Power Generation Project** means the proposed power plant project whose schedule of construction is not yet firm or committed;

**Indicative Transmission Project** means a proposed transmission project of the Transmission Network Owner beyond the first five (5) years of the Transmission Development Plan which the Regulator has not approved yet;

**International Electro-technical Commission (IEC)** refers to the international standards organization that prepares and publishes international standards for electro-technical Equipment;

**Interruption** means the loss of service to one or more Customers, resulting from one or more components of the Grid being on Outage;

**Interruption Duration** means the period from the initiation of an Interruption to the time when electricity service is restored;

**Interruption Frequency** means the number of times an Interruption occurs over a period of time;

**Independent Power Producer (IPP)** refers to a legal entity which is legally separate from the relevant Transmission Network Owner and Regulated Retailer but which owns facilities to generate electric power for sale to the Regulated Retailer, Third Party Retailers, or Large Load Customers or to perform other functions for the Grid such as Ancillary Services;

**Island Grid** means a power system or portion of the power system that is isolated from the rest of the Grid but where the Generating Units are capable of generating and maintaining a stable supply of electricity to the Customers within the isolated area;

**Isolation** means the electrical separation of a part or Component from the rest of the electrical system to ensure safety when that part or Component is to be maintained or when electric service is not required.

**Large Load Customer** means any Customer with a demand of at least 10MW;

**Local Safety Instructions** means a set of instructions regarding the Safety Precautions on Transmission Network or User System Equipment to ensure the safety of personnel carrying out work or testing;

**Load Flow Analysis** means a technical analysis which simulates the Power System operation or condition and provides the values of bus voltages, power flows, currents, and the power losses of the system;

**Load Shedding** means the process of deliberately removing pre-selected loads from the Transmission Network when there is generation deficiency or in response to an abnormal condition in order to maintain the integrity of the Grid;

**Load Shedding Plan** means the plan prepared by the System Operator detailing the pre-selected loads that will be deliberately removed from the Grid to manage the generation deficiency or when the Grid Security will be at risk;



**Load Shedding Schedule** means a schedule prepared by the System Operator of any planned Load Shedding actions;

**Long-Term Demand Forecast** means a Demand Forecast for the annual peak and energy demand of the Grid for at least the next 10 years;

**Loss-of-Load Expectation (LOLE)** means the measure of power system reliability in term of the expected number of days (or hour) in a given period that demand of the power system will not be met by the generation system which consist of all Generating Units connected to the Transmission Network due to outages of Generating Units and/or deficiency in generation capacity;

**Manual Load Shedding (MLS)** means the process of manually (i.e., non-automatically) and deliberately removing pre-selected loads from the Grid when there is generation deficiency or in response to an abnormal condition and in order to maintain the integrity of the Grid;

**Manual of Emergency Procedures** means a document containing a list of all parties to be notified and their contact details and the locations where critical personnel shall report for duty in cases of emergency and all instructions and procedures to be followed to manage the emergency of the Grid;

**Master Station** means an electronic device, that is a part of the SCADA system, that collects data from Remote Terminal Units, receives instructions and other inputs from its users, processes these instructions and inputs, and sends instructions to the Remote Terminal Units to control the remotely connected devices and Equipment;

**Material Effect** means a condition that has resulted or is expected to result in problems involving Power Quality, Power Sytem Reliability, System Loss, and safety. Such condition may require extensive work, modification, or replacement of Equipment in the Transmission Network or the User System;

**Medium-Term Demand Forecast** means a Demand Forecast for the monthly peak and energy demand for the next five (5) to ten (10) years;

**Merit Order Table** means the list showing the the Generating Units and their corresponding capacity and costs or prices arranged in a manner such that the lowest costs or prices is at the top of the list considering the power supply contracts of IPPs with the relevant Regulated Retailer and the schedule of Third Party IPPs for the supply of Third Party Large Load Customers;

**Metering Equipment** means the apparatus necessary for measuring electrical Active and Reactive Power and/or Active and Reactive Energy, inclusive of a multi-function meter, data logger and the necessary instrument transformers or transducers (voltage, current and phase shifting) and all associated wiring and communication devices;

**Metering Point** means the point in the Power System where Metering Equipment is located as agreed by the Transmission Network Owner and the User;

**Momentary Interruption** means an Interruption with duration less than five (5) minutes, or as defined by the Regulator;

**Momentary Average Interruption Frequency Index (MAIFI)** means a measure of Reliability of a Distribution Network, indicating the average frequency of momentary interruptions. It is computed by adding the number of Customers affected per Momentary Interruption over all Momentary Interruptions, and dividing the sum by the total number of Customers served;

**Month-Ahead Demand Forecast** means an hourly Demand Forecast prepared by the System Operator for the next Operating Month as part of the Operational Plan;

**Month-Ahead Generation Schedule** means an hourly Generation Schedule of the Operational Plan prepared and issued by the System Operator to meet the Month-Ahead Demand Forecast for the next Operating Month;

**Month-Ahead Operational Plan** means an Operational Plan for the next Operating Month prepared by the System Operator containing Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule;

**Month-Ahead Outage Plan** means the schedule containing the outages of power plant or Generating Units for the next Operating Month;

**Multiple Outage Contingency** means an Event caused by the failure of two or more Components of the Grid including Generating Units, transmission lines, and transformers;

**National Distribution Development Plan** means the component plan of the Power Development Plan prepared by the Technical Regulator that integrates and which identify the capacity, type and timing of Distribution Development Projects for the expansion, reinforcement and rehabilitation of Distribution Networks of Regulated Retailers;

**National Generation Development Plan** means the component plan of the Power Development Plan prepared by the Technical Regulator that integrates and optimize and which identify the capacity, type and timing of Power Generation Projects of Power Producers and Power Supply Plan of Regulated Retailers;

**National Power Development Plan** means the plan prepared by the Technical Regulator consisting of the National Generation Development Plan, National Transmission Development Plan and National Distribution Development Plan taking into consideration the national development plans and the power plant projects of Power Producers, Power Supply Plans of Regulated Retailers, Transmission Development Plans of Transmission Network Owners and Distribution Development Plans of Regulated Retailers;

**National Transmission Development Plan** means the component plan of the Power Development Plan prepared by the Technical Regulator which identify the capacity, type and timing of Transmission Development Projects for the expansion, reinforcement and rehabilitation of Transmission Networks of Transmission Network Owners;

**NISIT** refers to the National Institute of Standards and Industrial Technology of PNG;

**Non-Technical Loss** means the component of System Loss that is attributed to theft and erroneous meter reading;

**Normal State** means the operating state or condition of the Grid when the Power System Frequency, voltage, and transmission line and equipment loading are within their normal operating limits and the Operating Margin is sufficient;

**Operating Day** means a day of an Operating Week, Operating Month or Operating Year over which the operation of the Grid is being planned or the Grid is expected to be in operation;

**Operating Margin** means the available generating capacity in excess of the sum of the Power System Demand and System Loss within a specified period of time. This includes Frequency Regulating Reserve, Spinning Reserve, and Contingency Reserves.

**Operating Month** means a month of an Operating Year over which the operation of the Grid is being planned or the Grid is expected to be in operation;

**Operating Reserve** means the Ancillary Services including Frequency Regulating Reserve, Spinning Reserve and Fast Start Reserve;

**Operating Week** means a week of an Operating Month or Operating Year over which the operation of the Grid is being planned or the Grid is expected to be in operation;

**Operating Year** means a week of a calendar year over which the operation of the Grid is being planned or the Grid is expected to be in operation;

**Operational Plan** means a plan prepared by the System Operator detailing the Demand Forecast, the Outage plan and schedule of Generating Units, the Generation Schedule, the Ancillary Service plan and schedule and the Load Shedding plan and schedule (if any);

**Outage** means the state of a Component of the Power System when it is not available to perform its intended function due to some event directly associated with that Component. An Outage may or may not cause an Interruption;

**Planned Outage Notice** means a notice issued by the User to the System Operator for any planned outage to repair or maintain its Equipment or for any reasonable purpose, issued prior to the actual outage;

**Partial System Blackout** means the condition when a part of the Grid is isolated from the rest of the Grid and all generation in that part of the Grid has Shutdown;

**Point of Grounding** means the point on the Transmission Network or the User System at which grounding or earthing can be established for safety purposes;

**Point of Isolation** means the point on the Transmission Network or the User System at which Isolation can be established for safety purposes;

**Power Plant** means a power generating facility that consists of one or more Generating Units;

**Power Development Plan** means the plan consisting of Generation Development Plan, Transmission Distribution Development Plan and Distribution Development Plan prepared to support the economic and social development of PNG to ensure there is always sufficient power supply to meet the growing demand for electricity and that power supply from the Power Plants can be delivered safely, reliably and efficiently to end-users through the Transmission and Distribution networks;

**Power Generation Project** means a Power Plant project of identified in the Power Supply Plan of the Regulated Retailer or in the Generation Development Plan prepared by the Technical Regulator;

**Power Producer** refers to any person or entity, including IPPs and Regulated Retailer, authorized by the Government of PNG to owned or operate a power plant for the generation of electricity and/or perform functions such as Ancillary Services;

**Power Purchase Agreement (PPA)** an agreement between an Independent Power Producer and the Regulated Retailer or Large Load Customer that specifies the quantity, prices, terms and conditions pertaining to the delivery of electrical energy by the IPP;

**Power Quality** means the quality of the voltage, including its frequency and resulting current, that are measured in the Transmission Network or Connection Point of any User System;

**Power Supply Plan** means the plan indicating the plan prepared by Regulated Retailers detailing capacity, type and timing of its power plant projects and the capacity, type and timing of the demand planned to be supplied by IPPs through PPAs to meet future demand in the least-cost manner and in compliance with the standards and requirements of this Code;

**Power System** means the integrated system of Generating Units, Transmission Network, and Distribution Network for the supply and/or delivery electricity to Users; It is also referred to in this code as Grid;

**Power System Analysis** means the collective meaning for the technical analyses of Power Systems. This includes the analyses used to determine the safety, Power Quality, Reliability, Security, and Stability of Power Systems

**Power System Security Assessment** means a technical study to determine the adequacy of available capacity and energy of power generation and transmission facilities to meet the forecasted demand and capability of the Grid to remain in stable operation in both normal and single outage contingency conditions;

**Power System Stabilizer (PSS)** means an equipment installed to assist with low frequency oscillations by correcting the phase error present in fast excitation systems;

**PPL** refers to the PNG Power Ltd;

**PNG** refers to the Papua New Guinea;

**Preliminary Project Data** means the data pertaining to a User System and/or User Development at the time the User applies for a Connection Agreement or an Amended Connection Agreement with the Transmission Network Owner;

**Primary Response** means the automatic response of a Generating Unit to Frequency changes, released increasingly from zero to five seconds from the time of frequency change, and which is fully available for the next 25 seconds;

**Rated Power** means the technically specified value of maximum power for Equipment. In the case of Generating Unit, the Rated Power is the maximum power that it is capable of generating under a particular set of conditions found in its nameplate;

**Reactive Energy** means the integral of the Reactive Power with respect to time, measured in VARh or multiples thereof (kVARh or MVARh);

**Reactive Power** means the component of electrical power representing the alternative exchange of stored energy (inductive or capacitive) between sources and loads or between two power systems, measured in VAR or multiples thereof (kVAR or MVAR). For ac systems, it is the product of the root-mean-square (rms) values of the voltage and the quadrature component of the associated current. In a three-phase system, the total-three phase Reactive Power is the sum of the Reactive Power of each individual phase;

**Reactive Power Capability** means the capability of a Generating Unit to deliver Reactive Power under certain conditions, usually presented using a Reactive Power Capability Curve;

**Reactive Power Capability Curve** means a diagram that shows, for a Generating Unit, the Reactive Power Capability limit it is expected to operate under normal conditions versus the Real Power;

**Reactive Power Support** means the injection or absorption of Reactive Power from Generating Units or Power Plants to maintain Transmission Network voltages within the ranges prescribed in this code;

**Red Alert** means an alert issued by the System Operator when the Contingency Reserve of the Grid is zero, a generation deficiency exists, or there is critical loading or imminent overloading of transmission lines or substation transformers;

**Registered Equipment Data** means the actual updated data pertaining to the Transmission Network Equipment and in the case of User Equipment, the data from the Connected Project Data or its updated values;

**Regulated Retailer** means any person or entity, such as PPL, licensed by the Regulator to provide electricity service and supply to end-users;

**Regulator** refers to the Independent Consumer and Competition Commission (ICCC) established under the Independent Consumer and Competition Commission Act 2002;

**Reliability** means the performance of the Power System, Transmission Network or Distribution Network to supply and or deliver electricity to customers measured by

the frequency, duration, and magnitude of interruptions or other performance standards set by the Regulator for compliance of the regulated entities;

**Reliability Analysis** means a technical analysis of the Power System which determines the reliability performance of the Power System, Transmission Network or Distribution Network measured by frequency, duration, and/or magnitude of Interruptions to users of electricity;

**Remote Terminal Unit (RTU)** means an electronic device that collects data from measurement instruments, interfaces to a SCADA system, transmits telemetry data to a Master Station, and receives messages from the Master Station to control connected devices and Equipment;

**Requesting Safety Coordinator** means the Safety Coordinator assigned by the Transmission Network Owner (or the User) when it requests that Safety Precautions be established in the User System (or the Transmission Network);

**Safety Coordinator** means a person designated and authorized by the Transmission Network Owner (or the User) to be responsible for the coordination of Safety Precautions at the Connection Point when work or testing is to be carried out on a system which requires the provision of Safety Precautions for Equipment;

**Safety Log** a chronological record of messages relating to safety coordination sent and received by each Safety Coordinator;

**Safety Precautions** means the Isolation and Grounding of Equipment when work or testing is to be done on the Transmission Network or User System;

**Safety Rules** means the rules regarding the Safety Precautions on Transmission Network or User System Equipment to safeguard personnel carrying out work or testing;

**Safety Tag** means a label conveying a warning against possible interference or intervention as defined in the safety clearance and tagging procedures;

**Secondary Response** means the automatic response of a Generating Unit to Frequency which is fully available 25 seconds from the time of frequency change to take over from the Primary Response, and which is sustainable for at least 30 minutes;

**Security** means the continuous operation of a Power System in the Normal State, ensuring safe and adequate supply of power in the Grid, even when some parts or components of the system are on Outage;

**Security Red Alert** means an alert notice issued by the System Operator when law and order problems exist which may affect Grid operations;

**Short-Circuit Analysis** means a technical analysis of the Power System which determines the bus fault currents as well as currents and voltages that flow in the other parts of the Power System during a fault condition;

**Shutdown** means the condition of the Equipment when it is de-energized or disconnected from the Grid;

**Significant Incident** means an event that threatens the integrity of or affects the security of the Grid;

**Significant Incident Notice** means a notice issued by the System Operator or any User if a Significant Incident has transpired on the Grid or the User System, as the case may be;

**Significant Incident Report** means a report prepared and submitted by the System Operator to the Technical Regulator containing the details of Significant Incidents, such as date, time, and duration of occurrences, identified causes, effects of the Significant Incident, affected Users, the actions taken by the concerned parties, and the results of actions taken;

**Single Outage Contingency** means an event caused by the failure of exactly one component of the Grid such as a Generating Unit, a transmission line, or a transformer.

**Spinning Reserve** means a synchronized generating capacity from Generating Units allocated to cover the possible loss of a synchronized Generating Unit;

**Stability** means the ability of the dynamic Components of the Power System to return to a Normal State or a stable operating point after being subjected to some form of change or disturbance;

**Standard Planning Data** means the general data required by the Transmission Network Owner as part of the application for a Connection Agreement or Amended Connection Agreement;

**Start-Up** means the process of bringing a Generating Unit from Shutdown to Synchronized state;

**Statement of Readiness to Connect** a document, submitted by the applicant User to the Transmission Network Owner that attests to the readiness of the User System to be connected to the Transmission Network including the requests for a schedule for Connection and the test and commissioning reports;

**Substation Own-Use** the energy consumed by the substation Equipment and the facilities and devices for controlling and safeguarding the substation;

**Supervisory Control and Data Acquisition (SCADA)** means a system of computer-aided tools used to monitor and control the power system in real-time;

**Sustained Interruption** means any Interruption that is not classified as a Momentary Interruption (i.e., interruption of more than 5 minutes);

**Synchronized** means the state when connected Generating Units operate at the same frequency and where the phase angle displacements between their voltages vary about a stable operating point;

**System Average Interruption Frequency Index (SAIFI)** means a measure of the Reliability of a Distribution Network, indicating how often the average customer experiences a Sustained Interruption over a predefined period of time. It is computed by adding the number of Customers affected per Sustained Interruption over all Sustained Interruptions, and dividing the sum by the total number of Customers served;

**System Average Interruption Duration Index (SAIDI)** means a measure of the Reliability of a Distribution Network, indicating the total duration of Sustained Interruption for the average customer, commonly measured in customer-minutes or customer-hours of interruption. It is computed by multiplying the number of Customers affected per Sustained Interruption with the Interruption Duration, adding the products over all Sustained Interruptions, and dividing the sum by the total number of Customers served;

**System Loss** means the total energy injected into a Power System or any subsystem or the Transmission Network or the Distribution Network minus the total Energy delivered to Customers;

**System Operator** means the unit or group under the Transmission Network Owner responsible for the Scheduling and Dispatch of generation and Ancillary Services and for the real-time operation and control of the Power System to maintain its safety, Power Quality, Stability, Reliability, and Security;

**System Protection Dependability Index** means the degree of certainty that the Power System Protection will operate correctly. It is computed as the ratio of the number of correct operations (trippings) to the total number of operations (trippings) desired, expressed as a percentage;

**System Security Alert Notices** means the collective noun for the different types of alert notices issued by the System Operator to notify all Users of the Transmission Network of an existing Alert State;

**Technical Loss** means the component of System Loss that is inherent in the physical delivery of electric Energy including line and transformer conductor loss and transformer core loss;

**Technical Regulator** refers to the Department of Petroleum and Energy designated to perform technical regulatory functions under the Electricity Industry Policy of 2011;

**Tertiary Response** means the of a Generating Unit to Frequency changes that takes over from the Secondary Response and which is fully available 15 minutes from the time of Frequency change and sustainable for an indefinite amount of time afterwards in the absence of contrary conditions;

**Testing and Commissioning** means the putting into service a power system or equipment that has passed all required tests to show that the power system or equipment was erected and connected in the proper manner and can be expected to work satisfactorily;

**Third Party** means a legal entity which is legally separate from the relevant Transmission Network Owner or Regulated Retailer;

**Third Party Access Code** refers to the policy, rules and regulations and commercial arrangements promulgated by the Regulator for the Third Party connection and use of the Transmission Network;

**Third Party Retailer** means an entity with connection to the Transmission Network but which is legally separate from the relevant Regulated Retailer who is also the Transmission Network Owner;

**Total System Blackout** means the condition when all generation in the Grid has ceased, the entire Power System has shutdown, and the System Operator must implement a Black Start to restore the Grid to its Normal State;

**Transient Stability Analysis** means a technical analysis of the Power System which determines the ability of the Power System to return to a Normal State or a stable operating point after transient disturbances;

**Transmission Connection Service Procedure** means the procedure issued by the Transmission Network Owner as approved by the Regulator to Users applying for connection or modification of existing connection to the Transmission Network. For purposes of this Code, User System which was permanently disconnected and applying for reconnection shall be treated as applicant for new connection;

**Transmission Development Plan** means the plan prepared by Transmission Network Owner detailing the forecasts for peak demand and energy, the projects to expand, reinforce and rehabilitate the Transmission Network and for the connection or modification of connection of Users of the Transmission Network;

**Transmission Development Project** means a project for the expansion, reinforcement and rehabilitation of the Transmission Network and infrastructure for system operation identified in the Transmission Development Plan of the Transmission Network Owner;

**Transmission Network** means the whole or part of a high voltage (at least 66 kV) power transmission system extending between the Connection Points of Power Plants and the Connection Points of Distribution Networks or Large Load Customers;

**Transmission Network Owner** refers to PPL or any other holder of a transmission license granted by the Regulator;

**Transmission Network Outage Plan** means the plan that contains the coordinated planned outage schedule of the Transmission Network Equipment and lines;

**Under Frequency Relay (UFR)** means an electrical relay that operates when the Power System Frequency decreases to a preset value;

**User** refers to a person or entity that has system connected to and uses the Transmission Network and related facilities to which the Grid Code applies. The Users of the Transmission Network include (a) the IPPs selling electricity to the relevant Regulated Retailer who is also the Transmission Network Owner or to other Third Party (other Regulated Retailers and Large Load Customers), (b) the relevant Regulated Retailer who is also the Transmission Network Owner for its connected power plant (s), (c) Large Load Customers, (d) Other Regulated Retailers with connected distribution network to the Transmission Network, and (e) the relevant Regulated Retailer who is also the Transmission Network Owner for its connected distribution network;

**User Development** means the User System or Equipment to be connected to the Transmission Network or to be modified, including the relevant proposed new connections and modifications within the User System that requires a Connection Agreement or an Amended Connection Agreement.

**User System** means an electrical system owned and operated by a User of the Transmission Network.

**Variable Renewable Energy** means an energy generation system in which the primary energy source is intermittent such as solar and wind and which generation is cannot be scheduled like the conventional hydro and thermal plants;

**Voluntary Load Curtailment (VLC)** means the agreed self-reduction of demand by identified industrial and commercial end-users to assist in Frequency Control when generation deficiency exists;

**Week-Ahead Demand Forecast** means a Demand Forecast prepared by the System Operator for the next Operating Week as part of the Operational Plan;

**Week-Ahead Generation Schedule** means a Generation Schedule of the Operational Plan prepared and issued by the System Operator to meet the Week-Ahead Demand Forecast for the next Operating Week;

**Week-Ahead Operational Plan** means an Operational Plan for the next Operating Week prepared by the System Operator containing Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule;

**Week-Ahead Outage Plan** means the schedule containing the outages of power plant or Generating Units for the next Operating Week;

**Year-Ahead Demand Forecast** means a Demand Forecast prepared by the System Operator for the next Operating Year as part of the Operational Plan;

**Year-Ahead Generation Schedule** means a Generation Schedule of the Operational Plan prepared and issued by the System Operator to meet the Year-Ahead Demand Forecast for the next Operating Year;

**Year-Ahead Operational Plan** means an Operational Plan for the next Operating Year prepared by the System Operator containing Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule;

**Year-Ahead Outage Plan** means the schedule containing the outages of power plant or Generating Units for the next Operating Year;



**Yellow Alert** means an alert issued by the System Operator when the Contingency Reserve is less than the capacity of the largest synchronized Generating Unit;

## 1.2 Interpretation

### (a) Interpretation of the Grid Code

In this Code, unless the context otherwise requires:

- (i) headings are for convenience only and do not affect the interpretation of this Code;
- (ii) words importing the singular include the plural and vice versa;
- (iii) words importing a gender include any gender;
- (iv) an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other body corporate and any governmental agency;
- (v) a reference to any statute or regulation includes all statutes or regulations varying, consolidating, re-enacting, extending or replacing them and a reference to a statute includes all regulations, proclamations and orders issued under that statute;
- (vi) a reference to a document or a provision of a document includes an amendment or supplement to, or replacement of, that document or that provision of that document;
- (vii) an event which is required under this code to occur on or by a stipulated day which is not a Business Day may occur on or by the next Business Day;

## 1.3 Scope and Coverage

### (a) Scope of the Grid Code

This Code specifies the following:

- (i) Technical and performance standards to be complied by the Transmission Network Owner and its System Operator, Power Producers, Regulated Retailers, Large Load Customers, and any other Users of the Transmission Network;
- (ii) Rules, procedures and requirements for the connection of Users; and, for the planning of the development of Transmission Network, and for system operation; and
- (iii) Rules and procedures in the enforcement and settling disputes resulting from violations of this Code.

### (b) Coverage of Grid Code

The following entities or persons are covered by this Code:

- (i) Transmission Network Owners and their System Operator;

- (ii) Any Power Producer with a power plant connected to a Transmission Network who:
  - (A) sells electricity to the relevant Regulated Retailer who is also the Transmission Network Owner;
  - (B) sells electricity to Large Load Customers by wheeling this through the Transmission Network;
  - (C) sells electricity to a Third Party Retailer for resale to customers outside the exclusive service areas of the Regulated Retailer;
  - (D) sells electricity to a Third Party Retailer for resale to customers outside the exclusive service areas of the relevant Regulated Retailer who is also the Transmission Network Owner; and
  - (E) is also the Transmission Network Owner and Regulated Retailer who produce and sells electricity to customers.
- (iii) Large Load Customers with connection to the Transmission Network;
- (iv) Any Third Party Retailer who purchases electricity from Independent Power Producers (IPPs) and wheels this through the Transmission Network of the Transmission Network Owner; and
- (v) Any other Users of the Transmission Network of the Transmission Network Owner.
- (c) Consistency with the Third Party Access Code
  - (i) The Grid Code shall implement the policies specified in the Third Party Access (TPA) Code. In case of conflict, the specified rules or the intention of the rules of the TPA Code shall prevail.
  - (ii) In case the TPA Code is revised, this Code shall be reviewed and revised accordingly for consistency with the provisions of the TPA Code.

#### 1.4 Objectives

- (a) Policy Objectives of the Grid Code
 

The Grid Code supports the access, reliability, safety and affordability objectives of the Electricity Industry Policy by:

  - (i) Promoting transparency and non-discriminatory connection and access to the Transmission Network; and
  - (ii) Improving reliability and safety of the electricity networks by setting standards, rules and procedures in connection, planning and operation of Transmission Network.
- (b) Specific Objectives of the Grid Code

The objectives of this Code are to:

- (i) Define technical and performance standards and responsibilities of owners and users of the Transmission Network to implement the TPA Code; and
- (ii) Provide rules and procedures for the connection of Users, for power development planning, and for the safe, reliable, secured and efficient operation of the power systems in PNG.

---

## **2. Technical and Performance Standards**

---

### **2.1 Safety Standards**

- (a) **Mandatory Compliance to Safety Standards**
  - (i) The Transmission Network Owner and its System Operator shall develop, operate, and maintain the Transmission Network in a safe manner and shall always ensure a safe work environment for their employees and the public in accordance with the safety standards.
  - (ii) The electrical safety standards promulgated or adopted by NISIT shall govern the safety requirements for electrical installation, operation, and maintenance of the Transmission and Distribution Networks and the electrical system of connected facilities of Power Producers, Regulated Retailers and Large Load Customers.
  - (iii) The Technical Regulator shall adopt an occupational safety and health standards to protect every workingman in the Transmission and Distribution Networks and User System against the dangers of injury, sickness, or death through safe and healthful working conditions.
- (b) **Submission of Safety Records and Reports**

The Transmission Network Owner and User shall submit to the Technical Regulator copies of records and reports required by occupational safety and health standards.

### **2.2 Power Quality Standards**

- (a) **Nominal Frequency and Voltages**
  - (i) The nominal fundamental frequency of the power system in PNG shall be 50 Hz.
  - (ii) The nominal voltages for the high-voltage transmission of electricity shall be 66 kV and 132 kV or higher as adopted by the Technical Regulator.
  - (iii) The nominal voltages for the medium-voltage primary distribution of electricity shall be 11 kV, 22 kV and 33 kV.

- (iv) The nominal voltages for the low-voltage secondary distribution of electricity shall be 240/415 V.
- (b) Frequency Variations and Limits
  - (i) The System Operator shall maintain the system frequency within the limits of 49.5 Hz to 50.5 Hz during normal operation unless the Technical Regulator based on technical studies on specific Grid will allow broader limits.
  - (ii) During Single Outage Contingency, the system frequency may vary between 49 Hz and 51 Hz. In the case of Multiple Outage Contingency or when the Grid is in a state of emergency, the frequency may vary between 47 Hz and 52 Hz. No Generating Units shall disconnect from the Grid without the prior approval of the System Operator unless explicitly allowed by this Code and in accordance with the Automatic Under Frequency Load Shedding program and the guidelines for setting Under Frequency Relays of Generating Units prescribed by the System Operator as approved by the Technical Regulator.
  - (iii) During periods of supply shortfall when system security or reliability of supply is threatened, the System Operator is permitted to operate outside the frequency limits specified for normal operation and outage contingencies in accordance with the guidelines prescribed by the Technical Regulator.
- (c) Voltage Variations and Limits
  - (i) The Transmission Network Owner shall plan, design, build, and operate the Grid such that the voltage magnitude measured at the Connection Point of the Users of the Transmission Network varies:
    - (A) Within the limits of 0.95 and 1.05 per unit for Grids with demand of at least 10 MW; and
    - (B) Within the limits of 0.9 and 1.1 per unit for Grids with demand of less than 10 MW.
  - (ii) The System Operator shall control and maintain the voltage magnitude of the Grid in real-time operation:
    - (A) Within the limits of 0.95 and 1.05 per unit for Grids with demand of at least 10 MW; and
    - (B) Within the limits of 0.9 and 1.1 per unit for Grids with demand of less than 10 MW.
  - (iii) The Regulated Retailers and Large Load Customers shall plan, design, build, and operate their facilities that are connected to the Transmission Network such that the voltage magnitude of the power system is maintained within the limits of 0.95 and 1.05 per unit during normal operation.

- (d) Other Power Quality Standards
  - (i) The Technical Regulator shall set technical standards for voltage unbalance, harmonics, and flicker severity that the Transmission Network Owner shall use in planning, designing, building, and operating the Transmission Network.
  - (ii) Users shall ensure that their connection shall comply with the voltage unbalance, harmonics, and flicker severity set by the Technical Regulator.

## 2.3 Reliability Standards

- (a) Power System Reliability
  - (i) The power system shall be planned and operated so that the loss-of-load expectation (LOLE) of the generation system consisting of all Generating Units connected to the Transmission Network shall not exceed:
    - (A) 2 days per year for Grid with at least 10 MW demand
    - (B) 10 days per year for Grid with less than 10 MW demand
  - (ii) The power system shall be operated with Operating Reserve for Single Outage Contingency.
- (b) Transmission Network Reliability
  - (i) For Grids with at least 10MW demand, the Transmission Network shall be planned and operated for Single Outage Contingency. There shall be no customer interruptions under single outage conditions in the Transmission Network. The frequency and voltage shall be restored within normal limits after single outage conditions in the Transmission Network. However, the Regulator may allow part of the Transmission Network with only load customers at the receiving end (i.e., no power plants transmitting electricity through that part of the Transmission Network) to be constructed as radial transmission system.
  - (ii) Grids with less than 10MW demand need not comply with the Single Outage Contingency criteria. The Regulator based on technical and economic considerations shall set the frequency and duration of allowed customer interruptions of the Transmission Network.
  - (iii) A User, at its expense, may arrange with Transmission Network Owner for higher level of service reliability.
  - (iv) The Regulator shall set the standards and penalties for Transmission Network Owner for the Transmission Network reliability performance using the following indices:
    - (A) Average Frequency of Interruptions per kW
    - (B) Total Time of Interruption per kW

- (C) Average System Interruption Frequency Index (ASIFI)
- (D) Average System Interruption Duration Index (ASIDI)
- (v) The following outage events which cause interruptions shall be excluded in the calculation of transmission reliability indices:
  - (A) Transmission outages due to power plant or distribution lines and distribution substation failure
  - (B) Outages that occur outside the Transmission Network such as those outage events emanating from the power plants and distribution systems
  - (C) Outages due to generation deficiency
  - (D) Scheduled outages where Users have been notified at least seven (7) days prior to the planned outage
  - (E) Outages caused by Adverse Weather Conditions or *Force majeure*
  - (F) Outages due to other events that the Regulator may approve after due notice and public consultations
- (c) Distribution Network Reliability
  - (i) The Regulator shall set the reliability performance standards and penalties for the Regulated Retailer's Distribution Network using the following indices:
    - (A) System Average Interruption Frequency Index (SAIFI)
    - (B) System Average Interruption Duration Index (SAIDI)
    - (C) System Average Momentary Interruptions Frequency Index (MAIFI)
  - (ii) A retail customer, at its expense, may arrange with the Regulated Retailer for higher level of service reliability.
  - (iii) The following outage events which caused interruptions shall be excluded in the calculation of distribution reliability indices:
    - (A) Distribution outages due to generation, transmission line or transmission substation failure
    - (B) Outages that occur outside the distribution network such as those outage events emanating from the power plants and transmission system
    - (C) Scheduled outages where Users have been notified at least five (5) days prior to the planned outage
    - (D) Outages caused by Adverse Weather Conditions or *Force majeure*
    - (E) Outages due to other events that the Technical Regulator may approve after due notice and public consultations

## **2.4 System Loss Standards**

- (a) Classifications and Segregation of System Loss
  - (i) System Loss shall be classified into:
    - (A) Technical Loss
    - (B) Non-Technical Loss
  - (ii) Electricity consumption in transmission and distribution substations shall be reported separately as Substation Own-Use
  - (iii) Transmission Network Owner shall report segregated technical and non-technical system losses of the Transmission Network to the Regulator and the Technical Regulator according to their respective guidelines.
  - (iv) Regulated Retailer shall report segregated technical and non-technical system losses of the Distribution Network to the Regulator and the Technical Regulator according to their respective guidelines.
- (b) System Loss Target
  - (i) The Regulator shall set the system loss cap that may be pass-on to Users and consumers by the Transmission Network Owner and Regulated Retailers in their respective license.
  - (ii) The Technical Regulator shall monitor the system loss performance of the Transmission Network Owner and Regulated Retailer against the target set by the Regulator.

## **2.5 Protection Standards**

- (a) Fault Level
  - (i) The maximum allowable short circuit or ground fault current in the Transmission Network and Connection Point at 132 kV is 31.5 kA.
  - (ii) The maximum allowable short circuit or ground fault current in the Transmission Network and Connection Point at 66 kV is 25 kA.
  - (iii) The maximum allowable short circuit or ground fault current at 11 kV to 33 kV is 12.5 kA.
- (b) Fault Clearance Time
  - (i) The maximum Fault Clearance Time by the main or primary protection of the Transmission Network and Connection Point at 132 kV is 200 ms including relay and breaker action.
  - (ii) The maximum allowable short circuit or ground fault current in the Transmission Network and Connection Point at 66 kV is 300 ms including relay and breaker action.
- (c) Fault Withstand Time

- (i) The maximum Fault Withstand Time of circuit breakers in the Transmission Network shall be 3 seconds.
  - (ii) The maximum Fault Withstand Time of circuit breakers at the Connection Point of Users shall be 3 seconds.
- (d) Transmission Network Protection
  - (i) The Transmission Network shall have adequate and coordinated primary and backup protection at all times to limit the magnitude of disturbances when a fault or equipment failure occurs.
  - (ii) The User shall design, coordinate, and maintain its protection system to ensure the desired speed, sensitivity, and selectivity in clearing faults on the User's side of the Connection Point. Such protection system shall be coordinated with the protection system of the Transmission Network.
  - (iii) The reliability of the protection system shall be measured by System Protection Dependability Index. The Technical Regulator shall set the maximum System Protection Dependability Index for the Transmission Network.

## **2.6 Grounding Requirements**

- (a) At nominal voltages of 66 kV and 132 kV, the Transmission Network shall be effectively grounded with an Earth Fault Factor of less than 1.4.
- (b) At nominal voltages below 66 kV, the Transmission Network Owner shall specify the grounding requirements and the applicable Earth Fault Factor at the Connection Point.

## **2.7 Equipment Standards**

- (a) All Equipment at the Connection Point shall comply with the requirements of the International Electro-technical Commission (IEC) Standards or their equivalent national standards.
- (b) The prevailing standards at the time when the Connection Point was approved or modified shall apply to all Equipment at the Connection Point.

## **2.8 Maintenance Standards**

- (a) Equipment of the Transmission Network and of the User System shall be operated and maintained in accordance with Good Industry Practice and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the equipment of the Transmission Network or of the User System.
- (b) The Transmission Network Owner shall maintain a log containing the test results and maintenance records relating to its equipment of the Transmission Network and at the Connection Point of Users and shall make this log available when requested by the User.



- (c) The User shall maintain a log containing the test results and maintenance records relating to its equipment at the Connection Point and shall make this log available when requested by the Transmission Network Owner or System Operator.

## **2.9 Environmental and Social Safeguard Standards**

- (a) The Transmission Network Owner and Users shall comply with the environmental and social safeguard policies and legal frameworks that regulate access to land and management of environmental impacts for the development, construction, operation and maintenance of power facilities issued by the relevant government agencies in PNG.

## **2.10 Compliance and Performance Monitoring and Assessment**

- (a) Monitoring and Assessment
  - (i) The Technical Regulator shall monitor and assess the compliance of the Power Plants, Transmission Network, Distribution Network, and User System to the requirements of this Code.
  - (ii) The Technical Regulator shall monitor and assess the safety, power quality, reliability and system loss and other operational performance of the Transmission Network Owner and System Operator for the Transmission Network and of the Regulated Retailer for the Distribution Network.
  - (iii) The Technical Regulator shall also monitor the compliance of the Transmission Network Owner and Users to environmental and social safeguard policies and legal frameworks that regulate access to land and management of environmental impacts for the development, construction, operation and maintenance of power facilities.
- (b) Penalties for Non-compliance

The Regulator shall set penalties for non-compliance to the technical and performance standards specified under this Code.

# **3. Transmission Network Connection**

## **3.1 Transmission Connection Service Procedure**

- (a) Preparation, Submission and Publication of Transmission Connection Service Procedure
  - (i) The Transmission Network Owner shall establish its Connection Service Procedure which details the application, evaluation and implementation process, and requirements for new connection or

- modification to existing connection to the Transmission Network in accordance with the TPA Code and in compliance with this Code.
- (ii) The Transmission Network Owner shall submit to the Regulator for the approval of the Transmission Connection Service Procedure in accordance with the Third Party Access Code.
  - (iii) The Transmission Network Owner shall publish the Transmission Connection Service Procedure that has been approved by the Regulator in accordance with the TPA Code.
  - (iv) The Transmission Network Owner shall provide copy of the approved Transmission Connection Service Procedure to Users applying for new connection or modification of existing connection.
- (b) Connection Application Process
- (i) Any applicant User seeking a new connection or modification to an existing connection to the Transmission Network shall meet the requirements detailed in the Transmission Connection Service Procedure in accordance with this code to ensure that the proposed User System will not result in the degradation of the performance of the Grid.
  - (ii) Any applicant User seeking a new connection or modification to an existing connection shall accomplish the application form of the Transmission Network Owner which shall include a description of the proposed connection (or modification to an existing connection) and which shall comprise the User Development and the Connection Completion Date.
- (c) Evaluation of Proposed Connection and Grid Impact Studies
- (i) The Transmission Network Owner shall maintain a set of technical criteria and minimum standards that must be met by the proposed User Development in accordance with this Code. This set of criteria and standards shall be approved by Technical Regulator.
  - (ii) The Transmission Network Owner shall develop and maintain a set of technical planning studies required to evaluate the impact of any proposed connection (or proposed modification to an existing connection) to the Transmission Network.
  - (iii) The Transmission Network Owner shall process the application for connection (or modification to an existing connection) within 60 days from the submission of the completed application form. The 60-day processing period shall include any technical and economic analysis and Grid Impact Studies.
  - (iv) The Grid Impact Studies may be performed by the Transmission Network Owner or by any competent person or entity whose report shall be subject to the review and approval of the Transmission Network Owner.

- (v) After evaluating the application and performing Grid Impact Studies, the Transmission Network Owner shall inform the applicant whether the proposed new connection, (or modification to existing connection) is acceptable or not.
  - (vi) If the application is acceptable, the Transmission Network Owner and the applicant shall sign a Connection Agreement (or Amended Connection Agreement).
  - (vii) If the application is unacceptable, the Transmission Network Owner shall notify the applicant why the application is unacceptable. Applicant User shall modify the proposed connection to address the issues specified by the Transmission Network Owner in its evaluation.
  - (viii) If the Transmission Network Owner and the applicant User cannot reach an agreement on the proposed connection (or modification to an existing connection), the dispute shall be settled in accordance with the TPA Code.
- (d) Grid Impact Studies
  - (i) Grid Impact Studies shall establish whether or not the proposed new connection or modification to existing connection will degrade the Grid or the technical and performance standards of this Code will be violated.
  - (ii) If the proposed new connection or modification to existing connection will degrade the Grid or the technical and performance standards of this Code will be violated, the Grid Impact Studies shall determine the necessary reinforcement to mitigate the impact to the grid.
  - (iii) The mitigation of the impact of the proposed new connection, or modification to existing connection may require modification to User Development and/or reinforcements to the existing Transmission Network. The TPA Code rules on connection shall govern the financial responsibility for the reinforcements to the Transmission Network.
- (e) Connection Agreement
  - (i) The Connection Agreement shall specify the terms and condition for the connection (or modification to the existing connection) of User's system to the Transmission Network;
  - (ii) The work plan and schedule of the User Development shall be specified in the Connection Agreement.
- (f) Testing and Commissioning
  - (i) Upon completion of the User Development, including work at the Connection Point, the Equipment at the Connection Point and the

- User Development shall be subjected to the Testing and Commissioning in accordance with the Connection Agreement;
- (ii) At least one (1) month prior to the commissioning date, the applicant User shall submit the following information, pursuant to the terms, conditions and schedules specified in the Connection Agreement:
    - (A) Testing and Commissioning program
    - (B) Specifications of major Equipment in the User Development;
    - (C) Details of protection arrangements and settings;
    - (D) Information to enable the Transmission Network Owner to prepare the Fixed Asset Boundary Document, including the name of the Accountable Manager(s);
    - (E) Electrical Diagram and Connection Point Drawings of the User's Equipment at the Connection Point and other information that will enable the Transmission Network Owner to prepare the final Electrical Diagram and Connection Point drawings;
    - (F) Copies of all Safety Rules and Local Safety Instructions applicable to the User's Equipment at the Connection Point and a list of Safety Coordinators;
    - (G) A list of the names and contact details of authorized representatives, including documents authorizing them to make, on behalf of the user, binding decisions during Significant Incidents; and
    - (H) Test and commissioning procedures for the Connection Point and User System Development.
  - (iii) The Transmission Network Owner shall witness the Testing and Commissioning of the Connection Point facilities.
- (g) Statement of Readiness to Connect
- (i) After completion of Testing and Commissioning, the applicant User shall then submit to the Transmission Network Owner a Statement of Readiness to Connect that shall include the test and commissioning reports.
  - (ii) The applicant User shall also request for the connection schedule of the User System to the Transmission Network.
- (h) Certificate of Approval to Connect
- (i) Within 7 days after submission by applicant User of Statement of Readiness to Connect, the Transmission Network Owner shall verify the readiness of the User System and Connection Point for connection to the Transmission Network.

- (ii) If the User System and Connection Point facilities are found to be ready for connection, the Transmission Network shall immediately issue a Certificate of Approval to Connect.
- (i) Implementation of Connection
  - (i) The implementation of connection to the Transmission Network shall be made only after the Transmission Network Owner has issued the Certificate of Approval to Connect.
  - (ii) After the implementation of connection of User System, the User shall update the User's data based on actual parameters of installed equipment to be registered by the Transmission Network Owner as Connected Project Data.

### **3.2 Fixed Asset Boundary Document**

- (a) Preparation of the Fixed Asset Boundary Document
  - (i) The Transmission Network Owner shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.
  - (ii) The Transmission Network Owner shall prepare the Fixed Asset Boundary Document at least one (1) month prior to the Connection Completion Date of Connection of User System to the Transmission Network.
  - (iii) The User shall provide the information that will enable the Transmission Network Owner to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement (or Amended Connection Agreement).
- (b) Content of Fixed Asset Boundary Document
  - (i) The Fixed Asset Boundary Document for any Connection Point shall provide the information and specify the operational responsibilities of the Transmission Network Owner and the User for the following:
    - (A) Electrical equipment;
    - (B) Control equipment;
    - (C) Protection equipment;
    - (D) Metering equipment; and
    - (E) Communication system for the control, protection and metering
  - (ii) The Fixed Asset Boundary Document shall show precisely the Connection Point and shall specify the following:
    - (A) Equipment and their ownership;
    - (B) Accountable Managers;

- (C) Safety Rules and procedures including Local Safety Instructions and the Safety Coordinator(s) or any other persons responsible for safety;
  - (D) Operational procedures and the responsible party for undertaking maintenance; and
  - (E) Any agreement pertaining to emergency conditions.
- (iii) The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the Transmission Network Owner's and the user's sides of the Connection Point.
- (c) Accountable Managers
  - (i) Prior to the Connection Completion Date specified in the Connection Agreement (or Amended Connection Agreement):
    - (A) The User shall submit to the Transmission Network Owner a list of Accountable Managers who are duly authorized by the User to sign the Fixed Asset Boundary Documents on behalf of the User.
    - (B) The Transmission Network Owner shall submit to the User a list of Accountable Managers who are duly authorized by the Transmission Network Owner to sign the Fixed Asset Boundary Documents on behalf of the Transmission Network Owner.
  - (ii) A party wishing to change the list of Accountable Managers must notify the other party in writing at least one (1) month before the Connection Completion Date or as soon as possible. The notification must include the reason for the change.
  - (iii) Unless otherwise specified in the Connection Agreement (or Amended Connection Agreement), the construction, test and commissioning, control, operation and maintenance of equipment, accountability and responsibility shall follow ownership.
- (d) Signing and Distribution of the Fixed Asset Boundary Document
  - (i) Prior to the signing of the Fixed Asset Boundary Document, the Transmission Network Owner shall send a copy of the completed Fixed Asset Boundary Document to the user for revision or for confirmation of its accuracy.
  - (ii) After confirming the accuracy of the Fixed Asset Boundary Document, the Accountable Managers designated by the Transmission Network Owner and the user shall sign the Fixed Asset Boundary Document.
  - (iii) After the signing but not less than two (2) weeks before the connection implementation date, the Transmission Network Owner

shall provide two (2) copies of the Fixed Asset Boundary Document to the user with a notice indicating the date of issue, the issue number, and the connection implementation date of the Fixed Asset Boundary Document.

- (e) Modifications to an Existing Fixed Asset Boundary Document
  - (i) When a User has determined that a Fixed Asset Boundary Document requires modification, the User shall inform the Transmission Network Owner at least one (1) month before the implementation date of the modification.
  - (ii) When a Transmission Network Owner has determined that a Fixed Asset Boundary Document requires modification, the Transmission Network Owner shall prepare a revised Fixed Asset Boundary Document at least one (1) month prior to the implementation date of the modification.
  - (iii) When the Transmission Network Owner or the User has determined that a Fixed Asset Boundary Document requires modification to address an emergency condition, the Transmission Network Owner or the User shall immediately notify the other party. Both parties shall meet to discuss the required modification to the Fixed Asset Boundary Document and shall decide whether the change should be temporary or permanent in nature. Within one (1) week after the conclusion of the meeting(s) between the Transmission Network Owner and the User, the Transmission Network Owner shall provide the User with the revised Fixed Asset Boundary Document.
  - (iv) The same procedure specified in the previous subsection for signing and distribution of Fixed Asset Boundary Document shall apply to the revised Fixed Asset Boundary Document. The Transmission Network owner's notice shall indicate the revision(s), the new issue number, and the new date of issue.
  - (v) The Fixed Asset Boundary Documents shall be available at all times for the use of the operations personnel of the Transmission Network Owner and the User.

### **3.3 Electrical Diagrams and Connection Point Drawings**

- (a) Responsibilities of the Transmission Network Owner and Users
  - (i) The Transmission Network Owner shall specify the procedure and format to be followed in the preparation of the Electrical Diagram and Connection Point Drawings for any Connection Point including the standard Site and Equipment Identification system.
  - (ii) The User shall prepare and submit to the Transmission Network Owner the Electrical Diagram and Connection Point Drawings for all the Equipment on the User's side of the Connection Point, in

- accordance with the schedule specified in the Connection Agreement (or Amended Connection Agreement).
- (iii) The Transmission Network Owner shall provide the User with the Electrical Diagram and Connection Point drawings for all the Equipment on the Transmission Network Owner's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.
  - (iv) If the Connection Point is at the User's site, the User shall prepare and distribute a composite Electrical Diagram and Connection Point Drawings for the entire Connection Point. Otherwise, the Transmission Network Owner shall prepare and distribute the composite Electrical Diagram and Connection Point Drawings for the entire Connection Point.
- (b) Preparation of Electrical Diagrams and Connection Point Drawings
- (i) The Electrical Diagram and Connection Point Drawings shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.
  - (ii) If possible, all the Equipment at the Connection Point shall be shown in one Electrical Diagram and Connection Point drawings. When more than one Electrical Diagram and Connection Point drawings are necessary, duplication of identical information shall be minimized. The Electrical Diagram and Connection Point Drawings shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.
  - (iii) The Electrical Diagram and Connection Point Drawings shall be prepared with the standard site and equipment identification. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labelled "Spare Bay."
  - (iv) The title block of the Electrical Diagram and Connection Point Drawings shall include the names of authorized persons together with provisions for the details of revisions, dates, and signatures.
- (c) Changes to Electrical Diagrams and Connection Point Drawings
- (i) If the Transmission Network Owner or a User decides to add new Equipment or change an existing Site and Equipment Identification, the Transmission Network Owner or the User, as the case may be, shall provide the other party a revised Electrical Diagram and Connection Point Drawings, at least one month prior to the proposed addition or change.
  - (ii) If the modification involves the replacement of existing Equipment, the revised Electrical Diagram and Connection Point Drawings shall



be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

- (iii) The revised Electrical Diagram and Connection Point Drawings shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.
- (d) Validity of Electrical Diagram and Connection Point Drawings
  - (i) The composite Electrical Diagram and Connection Point Drawings prepared by the Transmission Network Owner or the User shall be the Electrical Diagram and Connection Point Drawings to be used for all operation and planning activities associated with the Connection Point.
  - (ii) If a dispute involving the accuracy of the composite Electrical Diagram and Connection Point Drawings arises, a meeting between the Transmission Network Owner and the User shall be held as soon as possible, to resolve the dispute.

### **3.4 Site and Equipment Identification and Labelling**

- (a) Site and Identification and Numbering System
  - (i) The Technical Regulator in consultation with NISIT shall establish a standard Site and Equipment Identification and numbering system for the sites and equipment in Transmission Network and User System.
  - (ii) The Transmission Network Owner and User shall use the standard Site and Equipment Identification and numbering system in all Fixed Asset Boundary Documents, electrical diagrams and drawings.
- (b) Labelling System
  - (i) The Technical Regulator in consultation with NISIT and the Transmission Network Owners and their System Operators shall establish a standard labelling system which specifies the dimension, sizes of characters, and colours of labels to identify the sites and equipment in Transmission Network and User System.
  - (ii) The Transmission Network Owner and Users shall be responsible for the provision and installation of a clear and unambiguous label showing the site and equipment identification at their respective systems.

### **3.5 Data Registration**

- (a) Stages of Data Registration
  - (i) The User applying for new connection, reconnection or modification to the existing connection shall submit data relating to the Connection Point and the User Development to the Transmission Network Owner in three (3) stages classified as:

- (A) Preliminary Project Data;
    - (B) Committed Project Data; and
    - (C) Connected Project Data;
  - (ii) At the time of application for connection, User shall submit Preliminary Project Data which shall contain the Standard Planning Data. When required for Grid Impact Studies, the Transmission Network Owner may require Detailed Planning Data.
  - (iii) Before signing the Connection Agreement or the Amended Connection Agreement, the User applying for connection shall update the Transmission Network Owner on the data it submitted relating to the Connection Point and User Development (i.e., the Preliminary Project Data).
  - (iv) The Preliminary Project Data shall become the Committed Project Data after the Connection Agreement or the Amended Connection Agreement is signed.
  - (v) After the implementation of connection, the Committed Project Data shall be updated, confirmed, and replaced with validated actual values of parameters and information about the equipment which shall become the Connected Project Data.
- (b) Data to be Registered
- (i) The User shall submit to the Transmission Network Owner the Standard Planning Data specified in Chapter 4 of this Code. This include the following:
    - (A) Connection Point and User Development Equipment data
    - (B) Generating Unit data for Power Producers
    - (C) Historical and forecast demand data for other Users
  - (ii) Power Producers shall also submit to the Transmission Network Owner Detailed Planning Data specified in Chapter 4 of this Code to enable the Transmission Network Owner and its System Operator as well as the Technical Regulator to conduct dynamic analysis of the power system for Grid Impact Study and Power Development Planning
- (c) Data Forms
- (i) The Transmission Network Owner shall develop the forms for all data to be submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.
  - (ii) The data forms shall be submitted to Technical Regulator for review and approval.

### 3.6 Connection Point

- (a) Location of Connection Point
  - (i) The User system shall be connected to the Transmission Network at the location agreed to by the Transmission Network Owner and the User.
  - (ii) The Transmission Network Impact Study for the proposed new connection or modification to existing connection shall determine the final location of the Connection Point.
- (b) Connection Point Voltage
  - (i) The User system shall be connected to the Transmission Network at the voltage level(s) agreed to by the Transmission Network Owner and the User.
  - (ii) The Grid Impact Study for the proposed new connection or modification to existing connection shall determine the final Connection Point voltage.
- (c) Control of Connection Point
  - (i) The Connection Point shall be controlled by a circuit breaker that is capable of interrupting the maximum short-circuit current at the point of connection.
  - (ii) Isolating switches shall be provided and arranged to isolate the circuit breaker for maintenance purposes.
  - (iii) The circuit breaker and the isolating switches as may be required by the Transmission Network Owner shall be remotely controllable through the SCADA and communication system of the System Operator.
- (d) Transformer Connection and Grounding at the Connection Point
  - (i) The Transmission Network Owner shall specify in the Transmission Connection Service Procedure the transformer connection and grounding requirements at the Connection Point of each type of User.
  - (ii) Where the transformer is grounded, its shall be effectively grounded with an Earth Fault Factor of less than 1.4 as specified in Section 2.6 of this Code.
- (e) Operation and Maintenance Responsibility for the Connection Point
  - (i) The Transmission Network Owner and the User shall be responsible for the operation and maintenance of their respective equipment at the Connection Point which shall be specified in the Connection Agreement.
  - (ii) The User may assign the responsibilities for operation and maintenance of its Equipment at the Connection Point to the

Transmission Network Owner. The Regulator shall approve the fees that the Transmission Network Owner will impose on the User for operation and maintenance of the User's Equipment at the Connection Point.

### **3.7 Protection System at Connection Point**

- (a) Minimum Protection Requirements
  - (i) The Transmission Network Owner shall specify in the Transmission Connection Service Procedure the protection requirements at the Connection Point of each type of User. The minimum protection requirements for the Transmission Network and User's Connection Point equipment are in Annex 1.
  - (ii) The Grid Impact Study for the proposed new connection or modification to existing connection shall determine the final protection requirements at the Connection Point.
  - (iii) The Transmission Network Owner and the User shall be solely responsible for the protection system of the electrical equipment and facilities on their respective sides of the Connection Point.
  - (iv) Where the User's Equipment is connected to the Transmission Network at 132 kV, a circuit breaker fail protection shall also be provided. The circuit breaker fail protection shall be designed to initiate the tripping of all electrically adjacent circuit breakers and to interrupt the fault current within the next 50 ms, in the event that the primary protection system has failed to interrupt the fault current within the prescribed fault clearance time.
  - (v) Where the automatic reclosure of a circuit breaker is required following a fault on the User system, automatic switching equipment shall be provided in accordance with the requirements specified in the Connection Agreement (or Amended Connection Agreement).
- (b) Design and Coordination of Protection System
  - (i) The protection of User's equipment at the Connection Point shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault-clearing and to minimize the impact of faults on the Transmission Network.
  - (ii) The Transmission Network Owner may require specific Users to provide other protection schemes which are designed and developed to maintain the security of the Grid or to minimize the risk and/or impact of disturbances on the Grid.
  - (iii) The Fault Clearance Time shall be specified in the Connection, Agreement (or Amended Connection Agreement). The Fault Clearance Time shall not be longer than the maximum allowable as specified in Section 2.5 of this Code.

### **3.8 SCADA and Communication System Requirements**

- (a) SCADA System
  - (i) The Transmission Network Owner shall specify in the Transmission Connection Service Procedure the System Operator's requirements and standards at the Connection Point of each type of User for the Supervisory Control and Data Acquisition (SCADA) System to serve as telemetry equipment for monitoring real-time information and controlling the Equipment at the Connection Point and User system.
  - (ii) The User shall provide Remote Terminal Unit (RTU) and other related equipment such as transducers and cables at the Connection Point that is ready for interconnection with the SCADA system of the System Operator.
  - (iii) The RTU shall be compatible with the Master Station protocol requirements and modem specifications of the System Operator.
  - (iv) In the event that the Master Station is changed, the Transmission Network Owner shall be responsible for any change needed for the RTU to match the new requirements.
- (b) Communication System
  - (i) A communication system shall be established so that the Transmission Network Owner, its System Operator and the Users can communicate with one another and exchange data signals for monitoring and controlling the Grid and the Equipment at Connection Point and User System during normal and emergency conditions.
  - (ii) The Transmission Network Owner shall specify in the Transmission Connection Service Procedure the System Operator's requirements and standards for the communication equipment at the Connection Point of each type of User.
  - (iii) The User shall provide the complete communication equipment that is ready for interconnection to the System Operator's communication system.
  - (iv) In the event of change in communication system of the System Operator, the Transmission Network Owner shall be responsible for the affected communication equipment at the Connection Point of the User.

### **3.9 Metering Requirements**

- (a) Metering Point
  - (i) The Metering Equipment shall be located at the Connection Point unless it is physically difficult, uneconomical or not practical to install it at the Connection Point.

- (ii) The Transmission Network Owner and the User shall agree on the location of the Metering Equipment.
  - (iii) If the Metering Equipment is not located at the Connection Point, the Transmission Network Owner and the User shall agree on the procedure and formula to adjust the meter readings to take into account the losses that were not captured due to the location of the Metering Equipment.
- (b) Responsibility for Metering Equipment
  - (i) The Transmission Network Owner shall provide the Metering Equipment at the agreed Metering Point of the User to measure the Active and Reactive Power and Active and Reactive Energy delivered from and/or to the system of the User. The User may provide the Metering Equipment as may be agreed between the User and the Transmission Network Owner provided that the Metering Equipment shall comply with the requirements and conform to the technical specifications set by the Transmission Network Owner in accordance with this Code. The financial arrangements for the Metering Equipment shall be governed by the TPA Code.
  - (ii) The Transmission Network Owner shall be responsible for maintaining the accuracy of the Metering Equipment.
  - (iii) The Transmission Network Owner shall be responsible for the maintaining the metering data collection, processing and archiving.
- (c) Technical Requirements for Metering Equipment
  - (i) The Metering Equipment shall include the following:
    - (A) Current transformer (CT);
    - (B) Voltage transformer (VT);
    - (C) Meter;
    - (D) Data logger and communication equipment;
    - (E) Electric circuit and cables; and
    - (F) Facility to seal and secure the meter; and
    - (G) Other components for checking the voltage and current.
  - (ii) The Metering Equipment shall comply with the following accuracy standards:
    - (A) For the meters: Accuracy class 0.5 for active energy metering and the requirements of IEC 62053-22 or equivalent standard; and 2.0 for reactive energy metering and the requirements of IEC 62053-23 or equivalent standard;
    - (B) For the Current Transformers (CT): Accuracy class 0.2 and the requirements of IEC 60044-1 or equivalent standards

- (C) For the Voltage Transformers (VT): Accuracy class 0.2 and the requirements of IEC 60044-1 or equivalent standards

### 3.10 Connection Conditions for Power Producers

- (a) Generating Unit Capability for Conventional Hydro and Thermal Power Plants
  - (i) The Generating Unit shall be capable of supplying its rated Active Power output within the limits of 0.80 lagging power factor and 0.90 leading power factor and in accordance with the Generating Unit's Reactive Power capability curve.
  - (ii) The Generating unit shall be capable of continuously supplying its rated Active Power output within the system frequency range of 49Hz to 51 Hz. Any decrease of power output occurring in the frequency of 47 to 49 Hz shall not be more than the required proportionate value of the system Frequency decay in accordance with frequency regulation characteristics of the Generating Unit.
  - (iii) The Generating Unit shall be capable of contributing to frequency and voltage control by continuous regulation of Active Power and Reactive Power in accordance with its specific roles for system operation such as governor free operation, Automatic Generation Control (AGC) and base load operation.
  - (iv) The Generating Unit shall be capable of supplying and maintain power:
    - (A) For at least ten (10) seconds when the system frequency remains below 47Hz.;
    - (B) For at least twenty (20) seconds when the system frequency varies from 47 to 48Hz;
    - (C) For at least one (1) minute when the system frequency varies from 48Hz to 48.5Hz;
    - (D) At all times when the system frequency varies from 48.5Hz to 51.5Hz;
    - (E) For at least one (1) minute when the frequency 51.5Hz to 52Hz;
    - (F) For at least ten (10) seconds when the system frequency varies above 52Hz;
  - (v) The Generating Unit shall be capable of withstanding the negative and zero sequence current under phase-to-phase and phase-to-ground fault conditions that take place near to the Generating Unit at least for the time until the faults have been cleared by backup protection.

- (vi) The Generating Unit and the power plant shall be capable of continuous operation during the occurrence of the following:
  - (A) Unbalanced loading from 5% to 10%; and
  - (B) Negative sequence current less than 5%.
- (b) Excitation system for Conventional Hydro and Thermal Power Plants
  - (i) The Generating Unit shall be fitted with a continuously variable, continuously acting automatic excitation control system (i.e., an automatic voltage regulator, AVR) to control the terminal voltage of the unit, without instability, over the entire operating range of the unit.
  - (ii) Where necessary for power system operations, the performance requirements of for excitation control facilities, including Power System Stabilizers, shall be specified in the Connection Agreement (or Amended Connection Agreement).
  - (iii) The Generating Unit shall be capable of supplying its Active and Reactive Power outputs if the voltage at the Connection Point is within the normal operating range of 0.95 per unit to 1.05 unit of the nominal value.
- (c) Speed-Governing System for Conventional Hydro and Thermal Power Plants
  - (i) The Generating Unit with Rated Power output greater than or equal to 1 MW shall be fitted with a speed-governing system capable of responding according to the minimum requirements specified in this Section of the Code.
  - (ii) The speed governor must be capable of being set so that it operates with an overall speed droop of between 2% and 10%. Unless waived by the Transmission Network Owner and its System Operator, the speed-governing system shall be capable of accepting raise and lower signals from the control center of the System Operator.
  - (iii) For Grids with demand of at least 10 MW, the Generating Units shall respond to system frequencies in accordance with their specific roles as assigned by the System Operator such as governor free, Automatic Generation Control, or base load generator.
  - (iv) For Grids with less than 10 MW, all synchronized Generating Units shall respond to system frequencies above 50 Hz (with allowable dead band) by reducing their Active Power output. Speed governors shall be set to give a 4% speed-droop characteristic or as otherwise specified in the Connection Agreement (or Amended Connection Agreement). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the system frequency excursion.
- (d) Generating System from Variable Renewable Energy



- (i) Generating system with variable renewable energy sources such as wind and solar power plants shall comply with the requirements specified in Section 3.10 (a).
  - (ii) The requirements for the connection of variable renewable energy sources shall consider the existing demand, capacity, type and number of generating plants and the ability of the Grid to manage the intermittent characteristics of variable renewable energy systems. The Technical Regulator shall determine the level of penetration and prescribe the requirements for connection and operation of the system with variable renewable energy.
- (e) Black Start Capability
  - (i) The Transmission Network shall be able to restore power during Total System Blackout through a number of strategically located generating plants with Black Start Capability and Dead Bus Access provision in the main access point.
  - (ii) The System Operator shall determine the number and strategic location of generating plants that shall have Black Start Capability and Dead Bus Access Capability which shall be considered in Power Development Plan.
  - (iii) The System Operator shall determine if the proposed generating plant of a Third Party shall be required to provide Black Start Capability and Dead Bus Access Capability in accordance with the Power Development Plan.
- (f) Fast Start Capability
  - (i) The System Operator shall determine the requirements for generating plants that shall have Fast Start Capability which shall be considered in the Power Development Plan.
  - (ii) The System Operator shall determine if the proposed generating plant of a Third Party shall be required to provide Fast Start Capability in accordance with the Power Development Plan.
- (g) Generating Unit Capability Testing
  - (i) Prior to the issuance of Certificate to Connect, the Generating Unit of the Power Producer shall be tested in accordance with the agreed procedure and standards to confirm the compliance for the following:
    - (A) Capability to operate within the Generating Unit's guaranteed performance and technical data;
    - (B) Capability to meet the applicable requirements of the Grid Code; and
    - (C) Capability to deliver the Ancillary Services that the Third Party Power Producer had agreed to provide.

- (ii) The System Operator shall issue instructions requiring tests to be carried out on any Generating Unit as required by this Code and in accordance with agreed testing procedures. The System Operator may also, at anytime for other than required by the Code, issue instructions requiring tests to be carried out on any Generating Unit as mutually agreed with the Power Producer.
  - (iii) All tests shall be recorded and witnessed by the authorized representatives of the Transmission Network Owner and its System Operator and the Power Producer.
  - (iv) If a Generating Unit fails the test, the Power Producer shall correct the deficiency within an agreed period to attain the relevant guaranteed performance and technical parameters for that Generating Unit. Once the Power Producer achieves the guaranteed performance and technical parameters of its Generating Unit that previously failed the test, it shall immediately notify the Transmission Network Owner who shall then require the Power Producer to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its guaranteed performance and technical parameters.
  - (v) If a dispute arises relating to the failure of a Generating Unit to pass a given test, the Transmission Network Owner and the Power Producer may submit the dispute for resolution to the Regulator which shall be resolved under the rules of the TPA Code.
- (h) Tests to be Performed
- (i) Active Power test shall demonstrate that the Generating Unit is capable of continuously generating the Active Power at its guaranteed performance and technical parameters. The Generating Unit shall pass the test if the measured values exceeded the capability as registered with the Transmission Network Owner.
  - (ii) The Reactive Power test shall demonstrate that the Generating Unit meets the guaranteed performance and technical parameters for Reactive Power Capability requirements. The Generating Unit shall pass the test if the measured values are within  $\pm 5$  percent of the Capability as registered with the Transmission Network Owner.
  - (iii) The Primary Response test shall demonstrate that the Generating Unit has the capability to provide Primary Response. The Generating Unit shall pass the test if the measured response in MW/Hz is within  $\pm 5$  percent of the required level of response within five (5) seconds.
  - (iv) The Fast Start capability test shall demonstrate that the Generating Unit has the capability to automatically Start-Up, synchronize with the Grid within 15 minutes and be loaded up to its offered capability. The Generating Unit shall pass the test if it meets the Fast Start capability requirements.

- (v) The Black Start test shall demonstrate that the Generating Plant with Black Start capability can implement a Black Start procedure. To pass the test, the Generating Unit shall start on its own, synchronize with the Transmission Network and carry load without the need for external power supply.
- (vi) The Dispatch accuracy test shall demonstrate that the Generating Unit meets the relevant Generation Scheduling and Dispatch Parameters. The Generating Unit shall pass the test if:
  - (A) In the case of synchronization, the process is achieved within  $\pm 5$  minutes of the registered synchronization time;
  - (B) In the case of meeting ramp rates, the actual ramp rate is within  $\pm 10\%$  of the registered ramp rate;
  - (C) In the case of meeting load reduction rates, the actual load reduction rate is within  $\pm 10\%$  of the registered Load reduction rate; and
  - (D) In the case of all other generation scheduling and dispatch parameters, values are within  $\pm 1.5\%$  of the declared values.
- (vii) The load acceptance test and load rejection test shall demonstrate that the Generating Unit can accept load in 25% incremental steps to 100% and load rejection of 25% incremental steps to 100% within the required time in accordance with the Connection Agreement.
- (viii) Other tests may be conducted to demonstrate the compliance of the Generating Unit to all requirements of this Code.

### 3.11 Connection Conditions for Users other than Power Producers

- (a) Under Frequency Relays for Automatic Load Shedding
  - (i) The Transmission Network Owner shall specify in the Transmission Connection Service Procedure the System Operator's requirements and standards for the Under Frequency Relays at the Connection Point of Users other than Power Producers.
  - (ii) Users of the Transmission Network other than Power Producers shall provide Under Frequency Relays at the Connection Point for automatic load shedding.
- (b) Automatic Load Shedding Scheme
  - (i) The Connection Agreement (or Amended Connection Agreement) shall specify the manner in which the demand, subject to automatic load shedding will be split into discrete MW load blocks to be actuated by Under Frequency Relays.
  - (ii) The tripping facility shall be designed and coordinated in accordance with the following reliability considerations:

- (A) Dependability: Failure to trip at any one particular Demand shedding point shall not harm the overall operation of the scheme. The Regulator shall specify the minimum overall dependability of the scheme.
- (B) Outages: The amount of Demand under control shall not be reduced significantly during the outage or maintenance of the equipment.

---

## **4. Power Development Planning**

---

### **4.1 Power Development Plan**

- (a) Objectives of the Power Development Plan
  - (i) The Power Development Plan shall support the economic and social development of PNG.
  - (ii) The Power Development Plan shall ensure that:
    - (A) There is always sufficient power supply to meet the growing demand for electricity in PNG;
    - (B) Power supply from the generating plants can be delivered safely, reliably and efficiently to end-users through the transmission and distribution networks;
    - (C) The development of generation capacity and the transmission and distribution systems are least-cost
  - (iii) The Power Development Plan shall guide prospective Transmission Network Owners, Regulated Retailers, Power Producers and other Third Parties in their respective development and business plans.
- (b) National Power Development Plan
  - (i) The Technical Regulator shall prepare the National Power Development Plan which shall include the following:
    - (A) National Generation Development Plan
    - (B) National Transmission Development Plan
    - (C) National Distribution Development Plan
  - (ii) The National Generation Development Plan shall identify the capacity, type, timing and to some extent site Power Generation Projects classified to meet the forecasted demand of the Grid considering the national development goals, the Power Generation Projects of IPPs, and the Power Supply Plan of Regulated Retailers as approved by the Regulator and. The Power Generation Projects shall be classified into:

- (A) Committed Power Generation Projects that has firm schedule of construction as evidenced by the available project financing and has been approved by the Regulator being part of the least-cost Power Development Plan; and
  - (B) Indicative Power Generation Projects that are proposed but whose financing and schedule of construction is not yet firm or committed.
- (iii) The National Transmission Development Plan shall include the Transmission Network expansion and reinforcement projects based on the Transmission Development Plan of licensed Transmission Network Owners as approved by the Regulator. The National Transmission Development Plan shall also include the interconnection of power systems (i.e., interconnection of Transmission Networks of two or more Transmission Network Owners). The National Transmission Development Plan shall consist of:
  - (A) Transmission Development Projects in the first five (5) years of the Transmission Development Plan which are classified as Committed Transmission Projects as approved by the Regulator; and
  - (B) Transmission Development Projects beyond five (5) years of the Transmission Development Plan which are classified as Indicative Transmission Projects.
- (iv) The National Distribution Development Plan shall include the Distribution Network substations and medium voltage primary distribution projects based on the Distribution Development Plan of Regulated Retailers as approved by the Regulator. The National Distribution Development Plan shall consist of:
  - (A) Distribution Development Projects in the first five (5) years of the Distribution Development Plan which are classified as Committed Distribution Projects as approved by the Regulator; and
  - (B) Distribution Development Projects beyond five (5) years of the Distribution Development Plan which are classified as Indicative Distribution Projects.
- (c) Power Supply Plan of Regulated Retailers
  - (i) The Regulated Retailers shall prepare least-cost Power Supply Plan to meet the forecasted demand of its customers.
  - (ii) The Power Supply Plan shall identify the capacity, type and timing of Committed Power Generation Projects and Indicative Power Generation Projects of the Regulated Retailer (i.e., the Regulated Retailer planned owned and controlled power plants being Power

- Producer itself) and the capacity, type and timing of power generation capacity to be procured by the Regulated Retailer from IPPs through PPAs in accordance with the TPA Code.
- (iii) The Power Supply Plan of the Regulated Retailer shall be submitted to the Regulator for approval.
- (d) Transmission Development Plan of Transmission Network Owner
- (i) The Transmission Network Owner shall prepare the least-cost Transmission Development Plan which shall include expansion and reinforcements of the Transmission Network for new connection or modification to existing connection of generating plants, distribution substations and facilities of other Users and for maintaining the operation of the Transmission Network according to the technical and performance standards of this Code.
  - (ii) The Transmission Development Plan shall identify the capacity, type and timing of Committed Transmission Development Projects and Indicative Transmission Development Projects in accordance with this Code.
  - (iii) The Five-Year Statement of the Transmission Development Plan of the Transmission Network Owner shall be submitted to the Regulator for approval.
- (e) Distribution Development of Regulated Retailers
- (i) The Regulated Retailer shall prepare the least-cost Distribution Development Plan which shall include the expansion and reinforcements of the distribution substations and medium voltage primary distribution feeders to meet the growing demand and connection requirements of retail customers and to meet the applicable performance standards for Distribution Network.
  - (ii) The Distribution Development Plan shall identify the capacity and timing of Committed Distribution Development Projects and Indicative Distribution Development Projects in accordance with this Code.
  - (iii) The Five-Year Statement of the Distribution Development Plan of the Regulated Retailer shall be submitted to the Regulator for approval.
- (f) Updating of Power Development Plan
- (i) The Power Development Plan shall be updated annually by the Technical Regulator according to the timeline set by the Energy Management Committee. Power Producers, Transmission Network Owners and Regulated Retailers shall submit to the Technical Regulator their respective updated plans.
  - (ii) The Power Development Plan shall be reviewed and updated if there is a proposed connection to the Grid that will have significant impact

on the technical and economic feasibility and timing of committed and indicative projects on the overall economics of the Power Development Plan.

#### **4.2 Planning Responsibilities**

- (a) Planning Responsibilities of Technical Regulator
  - (i) The Technical Regulator shall review the Power Supply Plan and Distribution Development Plan of Regulated Retailers and the Transmission Development Plan of Transmission Network Owners for consistency with national objectives, regulations regarding obtaining access to land and mitigation of environmental impacts, and compliance with Third Party Access Code and Grid Code.
  - (ii) The Technical Regulator shall prepare the National Generation Development Plan considering the most economic option to meet the requirements of Regulated Retailers specified in their Power Supply Plan. The Technical Regulator shall consider alternative Power Generation Projects, in lieu of the Power Generation Projects proposed by Regulated Retailers, that will aggregate the generation capacity requirements of Regulated Retailers and Large Load Customers to achieve economies of scale;
  - (iii) The Technical Regulator shall integrate the Distribution Development Plans of the power companies into the National Distribution Development Plan
  - (iv) The Technical Regulator shall integrate the Transmission Development Plans of Regulated Retailers including interconnection of power systems of two or more Transmission Network Owners into the National Transmission Development Plan.
  - (v) The Technical Regulator shall be responsible for evaluating and approving proposed major reinforcement and expansion projects of Transmission Network in relation to User Connection to the Transmission Network and to meet the Forecast Demand of the Grid;
  - (vi) The Technical Regulator shall be responsible for preparing the Power Development Plan for the approval of the Energy Management Committee
  - (vii) The Technical Regulator shall periodically review and update the planning procedures and standards of this Code.
- (b) Approval and Adoption of the National Power development Plan
  - (i) The Technical Regulator shall submit the integrated Power Development Plan to the Electricity Management Committee for approval.

- (ii) The Electricity Management Committee, after its review and approval, shall adopt and publish the Power Development Plan of PNG.
- (c) Planning Responsibilities of Transmission Network Owners
  - (i) Each Transmission Network Owner shall prepare Power Transmission Development Plan for their respective service areas.
  - (ii) The Transmission Development Plan of the Transmission Network Owner shall contain the Transmission substation and line expansion and reinforcements to meet the expansion of generation and distribution systems and the proposed connections of Transmission Network Users.
- (d) Planning Responsibilities of Regulated Retailers
  - (i) Each Regulated Retailer shall prepare Power Supply Plan and Distribution Development Plan for its service areas.
  - (ii) The Regulated Retailer shall be responsible in forecasting the Demand in its service areas to be considered in preparing the Power Supply Plan and Distribution Development Plan.
  - (iii) The Power Supply Plan of the Regulated Retailer shall contain the demand and energy requirements to meet the forecasted demand in its service area. The demand and energy requirements shall be characterized into:
    - (A) Base load;
    - (B) Intermediate load; and
    - (C) Peaking load.
  - (iv) The Power Supply Plan of the Regulated Retailer shall determine the least-cost generation capacity and energy mix to meet the demand in service areas in accordance with the Reliability performance standards prescribed in Section 2.3 of this Code.
  - (v) The Power Supply Plan of the Regulated Retailer shall indicate which portion of the demand and/or reserve requirements shall be met by building its own power plant and which portion of the demand and/or reserve requirements shall be procured from IPPs in accordance with the TPA Code.
  - (vi) The Distribution Development Plan of the Regulated Retailer shall contain distribution substation and line expansion and rehabilitation to meet its obligation to customers according to the license granted by the Regulator.
- (e) Planning Responsibilities of Transmission Network Owners
  - (i) Each Transmission Network Owner shall prepare Transmission Development Plan for its service areas.



- (ii) The Transmission Network Owner shall be responsible in forecasting the Demand in its service areas to be considered in preparing the Transmission Development Plan.
  - (iii) The Transmission Network Owner shall be responsible in analyzing the impact of the connection of new or modification to existing connection facilities such as generating plants, transmission substations and lines, and system of Large Load Customers that must be considered in preparing the Transmission Development Plan.
  - (iv) The Transmission Development Plan of the Regulated Retailer shall contain the expansion, reinforcements and rehabilitation of transmission substations and lines to ensure the adequacy and Reliability of the Transmission Network and the Security of the Grid in meeting the forecasted demand and the connection of Power Generation Projects. The Transmission Development Plan shall also include the expansion, rehabilitation and modernization of the SCADA and communications facilities to efficiently operate and control the Grid.
- (f) Planning Responsibilities of Users
- (i) Users shall submit updated data in a timely manner to the Transmission Network Owner who shall maintain a power system planning data bank.
  - (ii) All Users shall submit annually to the Transmission Network Owner the relevant planning data. These shall include the updated Standard Planning Data and the Detailed Planning Data.
  - (iii) Any User applying for connection or a modification of an existing connection to the Grid shall submit to the Transmission Network Owner the relevant Standard Planning Data and the Detailed Planning Data.

#### **4.3 Planning Criteria**

- (a) Technical Criteria
- (i) The Power Development Plan shall be prepared to meet the technical and performance standards specified in this Code.
  - (ii) The Power Supply Plan of Regulated Retailers and the National Generation Development Plan prepared by the Technical Regulator shall meet the following reliability criteria:
    - (A) Maximum 2 days per year Loss-of-Load Expectation for Grids with at least 10 MW demand; and
    - (B) Maximum 10 days per year Loss-of-Load Expectation for Grids with less than 10 MW demand.

- (iii) The Transmission Development Plan shall meet the following reliability criteria:
  - (A) For Grids with at least 10 MW demand, the Grid shall be developed with N-1 redundancy such that the power system will remain in Normal State during Single Outage Contingency provided that some parts of the Transmission Network may be permitted to be built as radial system in accordance with Section 2.3 (b) (i); and
  - (B) For Grids with less than 10 MW demand, the Grid shall be developed to meet the Average System Interruption Frequency Index (ASIFI) and Average System Interruption Duration Index (ASIDI) set by the Regulator.
- (iv) The Transmission Development Plan shall meet the following power quality criteria:
  - (A) Steady-state voltage between 0.95 to 1.05 per unit of nominal voltage for Grids with at least 10 MW demand
  - (B) Steady-state voltage between 0.9 to 1.1 per unit of nominal voltage for Grids with less than 10 MW demand
  - (C) Maximum Unbalance voltage set by the Regulator
- (v) The Transmission and Distribution Development Plan shall meet the following Short Circuit criteria:
  - (A) The three-phase short circuit and single line-to-ground fault current in the Transmission Network and any Connection Point at 132 kV will not exceed ninety percent (90%) of the 31.5 kA maximum fault standard.
  - (B) The three-phase short circuit and single line-to-ground fault current in the Transmission Network and any Connection Point at 66 kV will not exceed ninety percent (90%) of the 25 kA maximum fault standard.
  - (C) The three-phase short circuit and single line-to-ground fault current in the Transmission Network and any Connection Point at 11 kV to 33 kV will not exceed ninety percent (90%) of the 12.5 kA maximum fault standard.
- (vi) The Transmission and Distribution Development Plan shall meet the System Loss criteria set by the Regulator in the Electricity Regulatory Contract.
- (vii) The composite Generation and Transmission Development Plan shall meet the following transient stability criteria:
  - (A) The Grid shall return to a stable condition after an outage of any generating unit;

- (B) The Grid shall remain stable, i.e., Generating Units will remain in synchronism, during and after removal of three-phase and single line-to-ground faults;
  - (C) The voltage in the Transmission Network and any Connection Point will not collapse during and after removal of three-phase and single line-to-ground faults.
- (b) Economic Criteria
  - (i) The Power Development Plan shall be prepared based on least-cost criteria. It shall consider demand and supply sides energy efficiency potential and measures and integration of renewable energy resources in accordance with the national policies in PNG.
  - (ii) The capacity, type, and timing of new power plant projects in the Generation Development Plan shall be determined based on least-cost capacity and energy mix from available options.
  - (iii) The projects for the expansion and reinforcement of the Transmission Network and the Distribution Network shall be the least-cost among technically-feasible alternatives.
  - (iv) Projects that will improve the performance, such as higher reliability and lower system loss, of the Transmission Network and/or Distribution Network above the standards prescribed by this Code or set by the Regulator shall be approved based on benefit-cost analysis.
- (c) National Development Criteria
  - (i) The Power Development Plan shall meet other criteria and requirements pursuant to national development objectives and policies.
  - (ii) The economic criteria for power development planning shall be based on meeting the national development objectives and policies.
  - (iii) The development plans for power generation, transmission and distribution shall comply with existing policy and legal frameworks for obtaining access to land and mitigating environmental impacts.
- (d) Criteria for the Approval of Power Development Plan
  - (i) The Technical Regulator shall ensure that the standards and criteria prescribed in this Code are complied with by the Regulated Retailers and Transmission Network Owner in reviewing and recommending approval of their Power Supply Plan, Transmission Development Plan and Distribution Development Plan.
  - (ii) The standards and criteria prescribed in this Code shall be used in cases where the Technical Regulator will prepare or revise the Power Development Plan.

#### 4.4 Power Development Planning Procedures

- (a) Forecasting for Power Development Planning
  - (i) The Long-Term Demand Forecast shall consist of annual peak and energy demand of the Grid for at least the next ten (10) years.
  - (ii) The Medium-Term Demand Forecast shall consist of monthly peak and energy demand for the next 5 years.
  - (iii) The following factors shall be considered in preparing the demand forecasts for power development planning:
    - (A) Historical demand;
    - (B) Demographic and economic factors;
    - (C) National and local development plans;
    - (D) Plans of large industrial and commercial customers;
    - (E) Supply and demand sides energy efficiency potential and measures; and
    - (F) Other relevant plans and factors that influence the demand for electricity.
- (b) Preparation of Power Supply and Plan and National Generation Development Plan
  - (i) The Power Supply Plan and National Generation Development Plan shall be prepared to meet the Long-Term Demand Forecast;
  - (ii) The timing for new generating capacity and required reserve shall be determined based on reliability analysis and shall meet the reliability criteria prescribed by this Code.
  - (iii) The size and type of new generating capacity shall be determined based on economic analysis and shall meet the least-cost criteria.
  - (iv) The optimal locations of power plants shall be identified to meet the security and efficiency requirements of the Grid and to achieve least-cost development of generation, transmission and distribution systems.
  - (v) The economic analysis in preparing the least-cost Power Supply Plan and National Generation Development Plan shall consider the fixed investment, fixed and variable operation and maintenance, and fuel costs for the economic life of candidate power plants.
- (c) Preparation of Distribution Development Plan
  - (i) The Distribution Development Plan shall be prepared to meet the Long-Term and Medium-Term Demand Forecast;
  - (ii) The timing and size of new distribution substations shall be determined based on economic analysis of alternatives considering

- the fixed investment, and fixed and variable operation and maintenance costs for the economic life of candidate substations.
- (iii) The size of the medium voltage primary distribution feeders shall be determined based on Economic Load Reach criteria, that is, the least-cost life cycle cost to meet the expected demand and the power quality standards.
  - (iv) The routing of the medium voltage primary distribution feeders shall be determined based on least-cost among the technically feasible alternatives and available right-of-way.
- (d) Preparation of Transmission Development Plan
- (i) The Transmission Development Plan shall be prepared to meet the connection and transmission requirements of the Generation and Distribution Development Plans and the Large Customers with existing connection and planning to connect to the Transmission Network. It shall include the reinforcements due to connection;
  - (ii) The timing of new transmission substations shall consider the timing of new generating plants and distribution substations committed and indicated in the Generation Development Plan and the Distribution Development Plan, respectively.
  - (iii) The size of new and uprating of existing transmission substations shall be determined based on economic analysis of alternatives considering the fixed investment, fixed and variable operation and maintenance costs, and system losses for the economic life of candidate substations.
  - (iv) The size and voltage of the transmission lines shall be determined based on least-cost among the technically feasible alternatives and available right-of-way.

#### **4.5 Power Development Planning Data**

- (a) Planning Data
- (i) The data for power development planning shall be categorized into:
    - (A) Standard Planning Data
    - (B) Detailed Planning Data
  - (ii) The required Standard Planning Data shall consist of information necessary for the Transmission Network Owner to:
    - (A) Evaluate the impact of any User Development on the Grid or to the System of other Users; and
    - (B) Evaluate the technical performance of the Transmission Network prescribed by this Code in meeting the forecast demand of the Grid.

- (iii) The Detailed Planning Data shall include additional information necessary for the conduct a dynamic power system analysis.
  - (iv) The Standard Planning Data and Detailed Planning Data shall be categorized into:
    - (A) Estimated Equipment Data; and
    - (B) Registered Equipment Data.
  - (v) The Estimated Equipment Data shall contain the Transmission Network Owner's and User's best estimate of the values of parameters (such as typical values in nameplate) and information pertaining to their equipment.
  - (vi) The Registered Equipment Data shall contain validated actual values of parameters and information about the Transmission Network Owner's and User's equipment. For the User's Registered Equipment Data, it shall come from the Connected Project Data submitted to the Transmission Network Owner at the time of connection.
  - (vii) The Transmission Network Owner shall collate and process the planning data submitted by the Users into a cohesive forecast and use this in preparing the data for preparing the Transmission Development Plan.
  - (viii) The Regulated Retailer shall collate and process the planning data into a cohesive forecast and use this in preparing the data for preparing the Power Supply Plan and the Distribution Development Plan.
  - (ix) If a User believes that the cohesive forecast data prepared by the Transmission Network Owner does not accurately reflect its assumptions on the planning data, it shall promptly notify the Transmission Network Owner of its concern. The Transmission Network Owner and the User shall promptly meet to address the concern of the User.
- (b) Maintenance of Planning Data
- (i) The Transmission Network Owner shall consolidate and maintain the Transmission Network, power plant and distribution substation data required for the preparation of Transmission Development Plan.
  - (ii) The Regulated retailer shall consolidate and maintain the Distribution Network, power plant and customer data required for the preparation of Power Supply Plan and Distribution Development Plan.
  - (iii) The Standard Planning data and Detailed Planning Data for Generating Units in Annex 2 shall be submitted to the Transmission Network Owner by Power Producers, whether the power plant is

owned by the Regulated Retailer who is also the Transmission Network Owner or by a Third Party.

- (iv) Users shall submit the Standard Planning Data and Detailed Planning Data during connection of User System to the Transmission Network.
- (v) If there is any change to its planning data, the User shall notify the Transmission Network Owner of the change as soon as possible. The notification shall contain the time and date when the change took effect, or is expected to take effect, as the case may be. If the change is temporary, the time and date when the data is expected to revert to its previous registered value shall also be indicated in the notification.

#### **4.6 Power System Analysis**

- (a) Power System Analysis to be Conducted
  - (i) The Transmission Network Owner and the Technical Regulator shall conduct power system analysis to ensure the safety, reliability, security, and stability of the power system for the following:
    - (A) Preparation of the Power Supply Plan and the National Generation Development Plan and the Transmission Development to be integrated with the Power Development Plan;
    - (B) Evaluation of proposed generating plants and Transmission Network reinforcement projects; and
    - (C) Evaluation of any proposed User Development, which is submitted to Transmission Network Owner in accordance with an application for a Connection Agreement or an Amended Connection Agreement.
    - (D) Power system analysis shall be conducted periodically to assess the behaviour of the power system during normal and outage contingency conditions.
    - (E) Investigation of Significant Incident
  - (ii) The power system analysis shall be conducted to assess the security of power supply to meet the forecasted demand.
  - (iii) The power system analysis shall be conducted to assess the impact on the Transmission Network or to any User System of any proposed addition or change of equipment or facilities in the Transmission Network or the User System
- (b) Load Flow Analysis
  - (i) Load flow analysis shall be performed to evaluate the behaviour of the power system for the existing and planned generation and

- Transmission Network facilities under forecasted maximum and minimum load conditions
- (ii) Load flow analysis shall be performed to study the impact on the Grid of the connection of new generating plants, substations, transmission lines and User System.
  - (iii) The load flow analysis shall identify the load condition that produces the maximum power flows through the existing and proposed new lines and substations.
- (c) Short Circuit Analysis
- (i) Short circuit analysis shall be performed to evaluate the effect on Transmission Network equipment of the connection of new generating plants, substations, transmission lines, and other facilities that will result in increased fault duties for the equipment. These studies shall identify the equipment that could be permanently damaged when the current exceeds the design limit of the equipment. The studies shall identify the circuit breakers, which may fail when interrupting possible short circuit currents.
  - (ii) At least three-phase short-circuit and single line-to-ground fault studies shall be performed for all nodes of the Transmission Network for different feasible generation, load, and system circuit configurations. These studies shall identify the most severe conditions that the Transmission Network equipment may be exposed to.
- (d) Transient Stability Analysis
- (i) Transient stability analysis shall be performed to verify the impact of the connection of new generating plants, substations and transmission lines and changes in Transmission Network circuit configurations on the ability of the power system to seek a stable operating point following a transient disturbance. Transient Stability analysis shall simulate the outages of critical Transmission Network facilities such as 132 kV and 66 kV transmission lines, transformers and large Generating Units. The analysis shall demonstrate that the performance of the power system is satisfactory if the power system remains stable after any Single Outage Contingency for all forecasted load conditions.
  - (ii) Transient stability analysis shall be conducted to determine the possibility that Transient Instability problems may occur in the power system for all new 132 kV and 66 kV transmission lines or substations and generating plants connected at 132 kV. In other cases, the Transmission Network Owner shall determine the need of performing transient stability studies.
- (e) Reliability Analysis



- (i) Reliability analysis shall be performed to determine the adequacy of generation capacity of the power system using probabilistic methods such as Loss of Load Expectation (LOLE) and Expected Unserved Energy (EUE).
- (ii) Single Outage Contingency analysis shall be performed to determine the reliability and security of the Transmission Network.
- (iii) Reliability analysis shall be performed to determine the frequency and duration of customer interruptions in Distribution Network using probabilistic methods.

## **5. Power System Operation**

---

### **5.1 Operating States and Criteria**

- (a) Operating States
  - (i) The Grid shall be considered to be in the Normal State when all of the following conditions exist:
    - (A) The Operating Margin of the power system is sufficient;
    - (B) The Grid Frequency is within the limits of 49.5 and 50.5 Hz, as specified in Section 2.2;
    - (C) The voltages in the Transmission Network and all Connection Points are within the limits of 0.95 and 1.05 per unit of the nominal value per unit for Grids with demand of at least 10 MW or within the limits of 0.9 and 1.1 per unit for Grids with demand of less than 10 MW, as specified in Section 2.2; and
    - (D) The loading levels of all transmission lines and substation Equipment are below 90% of their continuous ratings.
  - (ii) The power system shall be considered to be in the Alert State when any one of the following conditions exists:
    - (A) The Contingency Reserve is less than the capability of the largest synchronized Generating Unit;
    - (B) The voltages at the Connection Points are outside the limits of 0.95 and 1.05 per unit but within the limits of 0.90 and 1.10 per unit of the nominal value per unit for Grids with demand of at least 10 MW or within the limits of 0.9 and 1.1 per unit but within the limits of 0.88 and 1.10 per unit of the nominal value per unit for Grids with demand of less than 10 MW;
    - (C) A weather disturbance has entered the PNG area of responsibility, which may affect Grid operations; or

- (D) Civil unrest or law and order problems exist, which may pose a threat to Grid operations.
- (iii) The power system shall be considered to be in the Emergency State when any one of the following conditions exists:
  - (A) There is generation deficiency;
  - (B) Multiple outage contingency;
  - (C) Voltages in the Transmission Network or Connection Point of Users are outside the limits of 0.90 and 1.10 per unit of the nominal value for Grids with demand of at least 10 MW or 0.88 and 1.10 per unit of the nominal value for Grids with demand of less than 10 MW; or
  - (D) The loading level of any transmission line or substation Equipment is above 110% of its continuous rating.
- (b) Operating Criteria
  - (i) The power system shall be operated so that it remains in the Normal State.
  - (ii) The power system shall be operated and maintained to meet the Power Quality standards specified in Section 2.2.
  - (iii) The Security of the power system shall be based on the Single Outage Contingency criterion. This criterion specifies that the Grid shall continue to operate in the Normal State following the loss of one Generating Unit, transmission line, or transformer.
  - (iv) Adequate Frequency Regulating Reserve and Contingency Reserve shall be available to stabilize the System and facilitate the restoration to the Normal State following a Multiple Outage Contingency.
  - (v) The Transmission Network voltage shall be operated at safe level to reduce the vulnerability of the power system to transient instability, dynamic instability, and voltage instability problems.
  - (vi) Following a Significant Incident that makes it impossible to avoid Island Grid operation, the Grid shall separate into several self-sufficient Island Grids, which shall be resynchronized to restore the Grid to a Normal State.
  - (vii) Sufficient Black Start and Fast Start capacity shall be available at strategic locations to facilitate the restoration of the Transmission Network to the Normal State following a Total System Blackout.

## 5.2 Operational Responsibilities

- (a) Operational Responsibilities of the System Operator
  - (i) The System Operator is responsible for preparing and implementing Operational Plan of the power system;

- (ii) The System Operator is responsible for performing all necessary studies to determine the safe operating limits that will protect the power system against any instability problems, including those due to multiple outage contingencies.
  - (iii) The System Operator is responsible for operating and maintaining Power Quality in the power system during normal conditions in accordance with the standards specified in Section 2.2;
  - (iv) The System Operator shall be responsible for scheduling and dispatching the Generating Units in accordance with the Economic Dispatch principles;
  - (v) The System Operator shall be responsible for determining, scheduling and dispatching the capacity needed to supply the required Operating Reserve of the power system.
  - (vi) The System Operator is responsible for ensuring that load-generation balance is maintained during emergency conditions and for directing system recovery efforts following these emergency conditions.
  - (vii) The System Operator is responsible for controlling the Transmission Network voltage variations during emergency conditions through a combination of direct control and timely instructions to Power Producers and other Users.
  - (viii) When separation into Island Grid occurs, the System Operator is responsible for maintaining normal system frequency in the resulting Island Grid and for ensuring that resynchronization can quickly commence and be safely and successfully accomplished.
  - (ix) The System Operator shall issue instructions to Users in order to maintain the reliability and security of the Grid which shall be followed by all Users. During emergencies, the instructions of the System Operator shall be followed by Users without question.
- (b) Operational Responsibilities of the Transmission Network Owner
- (i) The Transmission Network Owner is responsible for providing and maintaining all Equipment and facilities to enable the System Operator to control and maintain Power Quality according to standards.
  - (ii) The Transmission Network Owner is responsible for designing, installing, and maintaining the control and protection system that will ensure the timely disconnection of faulted facilities and Equipment.
  - (iii) The Transmission Network Owner is responsible for executing the instructions of the System Operator during normal and emergency conditions.
- (c) Operational Responsibilities of Power Producers

- (i) The Power Producer is responsible for maintaining its Generating Units to fully deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement.
- (ii) The Power Producer is responsible for providing accurate and timely planning and operations data to the Transmission Network Owner and System Operator.
- (iii) The Power Producer shall be responsible for ensuring that its Generating Units will not disconnect from the Transmission Network during disturbances except when the Frequency or Voltage Variation would damage Power Producer's Equipment.
- (iv) The Power Producers is responsible for executing the instructions of the System Operator during normal and emergency conditions.
- (d) Operational Responsibilities of Other Users
  - (i) The User, other than Power Producer, is responsible for assisting the System Operator in maintaining Power Quality in the Transmission Network by correcting any User facility that causes Power Quality problems.
  - (ii) The User, other than Power Producer, shall be responsible in ensuring that its System will not cause the Degradation of the Grid. It shall also be responsible in undertaking all necessary measures to remedy any Degradation of the Grid that its System has caused.
  - (iii) The User, other than Power Producer, is responsible for maintaining an Automatic Load Shedding scheme, as necessary, to meet the targets agreed to with the System Operator.
  - (iv) The User is responsible for executing the instructions of the System Operator during normal and emergency conditions.

### **5.3 System Operation Notices and Reports**

- (a) System Operation Notices
  - (i) The following System Security Alert Notices shall be issued, without delay, by the System Operator to notify all Transmission Network Users of an existing alert state:
    - (A) Yellow Alert when the Contingency Reserve is less than the capacity of the largest Synchronized Generating Unit;
    - (B) Red Alert when the Contingency Reserve is zero or a generation deficiency exists or if there is Critical Loading or Imminent Overloading of transmission lines or substation transformers;
    - (C) Blue Alert when a weather disturbance has entered the PNG area of responsibility which may affect the power system operation;

- (D) Security Red Alert when peace and order problems exist, which may affect the power system operation.
  - (i) A Significant Incident Notice shall be issued by the System Operator, the Transmission Network Owner or any User if a Significant Incident has transpired on the Transmission Network or the System of the User, as the case may be. The notice shall be issued within 15 minutes from the occurrence of the Significant Incident. The notice shall include the initial corrective measures that were undertaken by the System Operator, the Transmission Network Owner, or the User, as the case may be.
  - (ii) A Planned Outage Notice shall be issued by a User to the Transmission Network Owner through the System Operator for any planned outage to repair or maintain its equipment at least seven (7) days prior to the actual repair or maintenance. The System Operator shall notify the User of its approval or disapproval of the User's planned outage within two (2) days upon submission of the request.
  - (iii) A Load Shedding Notice shall be issued by the System Operator for any load reduction immediately when it determined that there is generation deficiency or transmission constraint.
- (b) System Operation Reports
- (i) The Transmission Network Owner shall submit to the Technical Regulator the following regular reports of the System Operator:
    - (A) Annual System Operation and Performance Report of the previous Operating Year not later than the end of January of the current year; and
    - (B) Monthly System Operation and Performance Report of the previous Operating Month not later than the end of Week 2 of the current month.
  - (ii) The Transmission Network Owner shall submit to the Technical Regulator the Significant Incident Report of the System Operator within a month after the occurrence of any Significant Incident in the Transmission Network or User System.
  - (iii) The Transmission Network Owner or User shall submit Special Reports upon instructions of the Technical Regulator or at the request of any party through the Technical Regulator. In the case of the request by a party other than by a government agency, the requesting party shall be responsible for the expenses incurred in preparing the Special Report.

## 5.4 Operational Planning

- (a) Operational Plans

- (i) The System Operator shall prepare the following Operational Plans based on Power System Security Assessment:
    - (A) Year-Ahead Operational Plan;
    - (B) Month-Ahead Operational Plan;
    - (C) Week-Ahead Operational Plan; and
    - (D) Day-Ahead Operational Plan.
  - (ii) The Year-Ahead Operational Plan shall specify the details of Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule (if any) for each month of the following Operating Year. The Year-Ahead Operational Plan shall be submitted to the Technical Regulator not later than the last Business Day of Week 1 of October each year.
  - (iii) The Month-Ahead Operational Plan shall specify the details of Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule (if any) for each week of the following Operating Month. The Month-Ahead Operational Plan shall be submitted to the Technical Regulator not later than the last Business Day of Week 3 of each month.
  - (iv) The Week-Ahead Operational Plan shall specify the details of Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule (if any) for each day of the following Operating Week. The Week-Ahead Operational Plan shall be submitted to the Technical Regulator not later than the last Business Day of each Week.
  - (v) The Day-Ahead Operational Plan shall specify the details of Demand Forecast, Outage Schedule of power plants, Generation Schedule, Ancillary Services Schedule, and Load Shedding Schedule (if any) for each hour of the following Operating Day. The Day-Ahead Operational Plan shall be prepared not later than 1500H of each day. Upon request of the Technical Regulator, the System Operator shall submit the Day-Ahead Operational Plan.
- (b) Demand Forecast for Operational Planning
- (i) The System Operator shall prepare the following Demand Forecasts for operational planning:
    - (A) Year-Ahead Demand Forecasts;
    - (B) Month-Ahead Demand Forecasts;
    - (C) Week-Ahead Demand Forecasts; and
    - (D) Day-Ahead Demand Forecasts.

- (ii) The Year-Ahead Demand Forecast shall include the Peak and Energy Demand of the Transmission Network, transmission substations and Connection Points for each month of the following Operating Year.
  - (iii) The Month-Ahead Demand Forecast shall include the Peak and Energy Demand for each week of the following Operating Month.
  - (iv) The Week-Ahead Demand Forecast shall include the Peak and Energy Demand for each day of the following Operating Week.
  - (v) The Day-Ahead Demand Forecast shall include the Hourly Demand for each day of the following Operating Week.
  - (vi) Users shall submit historical and forecast demand data to the System Operator for the preparation of the Demand Forecasts for Operational Planning not later than Week 1 of September of each year. The User shall immediately inform of any change and provide the updated forecast data to the System Operator. The System Operator may require submission of updated or additional forecast data which shall be complied with by the User.
- (c) Grid Outage Plan
- (i) The System Operator shall prepare the following Grid Outage Plans:
    - (A) Year-Ahead Outage Plan;
    - (B) Month-Ahead Outage Plan;
    - (C) Week-Ahead Outage Plan; and
    - (D) Day-Ahead Outage Plan.
  - (ii) The Grid Outage Plan shall be prepared taking into account the following:
    - (A) Forecasted Demand;
    - (B) Outage Plans actually implemented;
    - (C) The requests by Users for changes in their Outage Schedules;
    - (D) The requirements for the maintenance of the Transmission Network;
    - (E) The need to minimize the total cost of the required maintenance;
    - (F) The need to minimize the threat on security of the Grid; and
    - (G) Any other relevant factor.
  - (iii) The Power Producer shall provide the System Operator not later than the last Business Day of last week of June its request for Outage Schedule of each Generating Unit for the following

Operating Year. The following information shall be included in the Power Producer's request for Outage Schedule:

- (A) Identification of the Generating Unit and the MW capacity involved;
  - (B) Reasons for the outage;
  - (C) Expected duration of the outage;
  - (D) Preferred start and end dates for the outage; and
  - (E) If there is flexibility in dates, the earliest start date and the latest end date.
- (iv) The System Operator shall endeavour to accommodate the Power Producer's request for Outage Schedule at particular dates in preparing the Grid Outage Plan.
  - (v) The System Operator shall provide the Power Producer a written copy of the Power Producer's approved Outage Schedule.
  - (vi) If the Power Producer is not satisfied with the Outage Schedule allocated to its Generating Unit, it shall notify the System Operator to explain its concern and to propose changes in the Outage Plan. The System Operator and the Power Producer shall discuss and resolve the problem in scheduling. The Grid Outage Plan shall be revised by the System Operator based on the resolution of the Power Producer's concerns.
  - (vii) The Grid Outage Plan for the next Operating Year shall be finalized by the System Operator not later than the last Business Day of month of August of the current year.
- (d) Power System Security Assessment
    - (i) The System Operator shall conduct Power System Security Assessment in preparing the Operational Plan which include the following:
      - (A) Determination of Capacity Margin and Energy Margin for the Supply-Demand Outlook based on the Forecast Demand and Grid Outage Plan;
      - (B) Reliability analysis of the power system considering the Grid Outage Plan; and
      - (C) Dynamic analysis of the power system for normal, faulted and single outage contingency conditions.
    - (ii) The reliability analysis shall determine the Loss-of-Load Expectation of the generation system and the Expected Unserved Energy.
    - (iii) The dynamic analysis of the power system shall capture the dynamic response of Generating Units and their excitation and speed-



governing systems. These shall include steady-state, transient and voltage stability analyses of the power system.

- (iv) The System Operator shall determine the required Operating Reserves and other Ancillary Services to operate and control the power system in a secured and reliable manner.
- (v) Where there is generation capacity and/or energy deficiency, the System Operator shall prepare a Load Shedding Plan to maintain security of the Transmission Network.
- (vi) Where there is transmission congestion or constraint, the System Operator shall determine the required load reduction and prepare a Load Shedding Plan to maintain security of the Transmission Network.
- (vii) Where the System Operator determines that Outage Schedule of any Power Producer will affect the Security of the Grid, the System Operator shall propose alternative schedule for the affected Power Producer and revise the Grid Outage Plan, accordingly.

## **5.5 Frequency and Voltage Control**

- (a) Methods of Frequency and Voltage Control
  - (i) The system frequency shall be controlled by the timely use of Automatic Generation Control (AGC), Frequency Regulating Reserve, Contingency Reserve, and Demand Control.
  - (ii) Demand Control shall be implemented when the System Operator has issued a Red Alert Notice and shall include the following:
    - (A) Automatic Load Shedding;
    - (B) Manual Load Shedding;
    - (C) Voluntary Load Curtailment by customers; and
    - (D) Embedded Generator of customers.
  - (iii) The voltage of the Transmission Network can be controlled by managing the Reactive Power supply through the operation of the following equipment:
    - (A) Synchronous Generating Units;
    - (B) Synchronous condensers;
    - (C) Static VAR compensators;
    - (D) Shunt capacitors and reactors; and
    - (E) On-load tap changing transformers.
- (b) Automatic Generation Control and Operating Reserve
  - (i) The System Operator shall determine the Generating Units that shall be operated in Automatic Generation Control.

- (ii) The System Operator shall determine the level of Frequency Regulating Reserve which shall be provided by Generating Units operating in Primary Response mode.
  - (iii) The System Operator shall determine the level of Spinning Reserve which shall be provided by Generating Unit operating in Secondary Response mode.
  - (iv) The System Operator shall determine the level of Backup Reserve which shall be provided by Generating Unit operating in Tertiary Response mode.
  - (v) The level of Operating Reserve to be arranged by the System Operator shall be approved by the Technical Regulator.
- (c) Automatic Under Frequency Load Shedding (AUFLS)
  - (i) The System Operator shall establish the level of demand required for Automatic Under Frequency Load Shedding in order to limit the consequences of a major loss of generation in the Transmission Network. The User shall prepare its Automatic Under Frequency Load Shedding program in consultation with the System Operator.
  - (ii) The User demand that is subject to Automatic Under Frequency Load Shedding shall be split into rotating discrete MW blocks. The System Operator shall specify the number of blocks and the under frequency setting for each block.
  - (iii) To ensure that a subsequent fall in frequency will be contained by the operation of Automatic Under Frequency Load Shedding, additional Manual Load Shedding shall be implemented so that the loads that were dropped by Automatic Under Frequency Load Shedding can be reconnected.
  - (iv) If an AUFLS has taken place, the affected Users shall not reconnect their feeders without clearance from the System Operator. The System Operator shall issue the instruction to reconnect, once the Frequency of the Transmission Network has recovered. Subject to available generation, the first circuit to trip shall be the first to be energized.
- (d) Manual Load Shedding
  - (i) Whenever there is generation capacity deficiency for reasons including but not limited to delays in the commissioning of generation projects, unanticipated load growth or insufficient water levels) or transmission congestions that will require load reduction to maintain security of the Grid, the System Operator shall establish the schedule and level of demand reduction for Manual Load Shedding of each User.
  - (ii) The User shall not reconnect the feeders disconnected by Manual Load Shedding unless instructed by the System Operator to do so.

- (iii) Where a generation capacity deficiency is prolonged beyond one day, the System Operator may establish a longer-term schedule of rotating Manual Load Shedding by distribution feeder or on a similar basis. In such situation, the System Operator shall publish any such schedule in at least two daily newspapers circulating within the areas affected, on its website and by such other means as it considers best suited to bring this to the attention of affected Users.
- (e) Demand Control
  - (i) Voluntary Load Curtailment (VLC) or any similar scheme shall be implemented wherein the customers are divided into VLC groups (e.g. Monday Group, Tuesday Group, etc.).
  - (ii) Load customers participating in the VLC shall voluntarily reduce their respective Loads for a certain period of time depending on the extent of the generation deficiency.
  - (iii) Load customers with embedded generation shall also participate in Demand Control program arranged by the System Operator.
  - (iv) Customers who implemented a VLC and/or embedded generation shall provide the System Operator with the amount of Demand reduction actually achieved through the VLC and/or embedded generation scheme.

## 5.6 Ancillary Services

- (a) Operating Reserve Ancillary Services
  - (i) The System Operator shall plan, schedule and dispatch Operating Reserve Ancillary Services to control the system frequency of the power system within the standards specified in Section 2.2 of this Code.
  - (ii) The Operating Reserve shall include Frequency Regulating Reserve to maintain system frequency within the normal operating limits in response to incremental variations in demand and Contingency Reserve to restore and maintain system frequency to normal operating limits in response sudden increase in load, loss of any Generating Unit, or outage of any transmission equipment.
  - (iii) The Contingency Reserve shall include Spinning Reserve which are operating and synchronized with the Transmission Network and Backup Reserve which are ready to start and synchronize with the Transmission Network
- (b) Voltage Control and Reactive Power Support Ancillary Services
  - (i) If necessary to maintain the voltage in the Transmission Network and Connection Points within the normal limits specified in Section 2.2, the System Operator shall arrange the Voltage Control and Reactive Power Support Ancillary Services.

- (ii) The System Operator shall schedule and dispatch the Power Producer's voltage to be maintained at the Connection Point of the Power Producer.
  - (iii) The System Operator shall determine the equipment necessary for Voltage Control and Reactive Power Support to be installed in the Transmission Network.
- (c) Black Start Ancillary Services
  - (i) The System Operator shall establish the required power plants in strategic locations to provide Black Start and Dead Bus Access and restore power from Total System Blackout.
  - (ii) The System Operator shall ensure that at all times there are available Black Start power plants either in operation or on standby.
- (d) Power Producers to Provide Ancillary Services
  - (i) The Ancillary Services shall be provided by:
    - (A) Power plant(s) owned and controlled by the Power Producer who is also the licensed Transmission Network Owner and Regulated Retailer;
    - (B) Power plant(s) owned or controlled by Independent Power Producers (IPP) in accordance with:
      - i. The Power Purchase Agreement (PPA) if such Ancillary Services are to be provided by the IPP plant(s); and
      - ii. The Ancillary Services Agreement between the Transmission Network Owner and the IPP if not included in the PPA.
    - (C) Power plant(s) owned or controlled by Third Party Power Producer wheeling power through the Transmission Network in accordance with the Ancillary Services Agreement between the System Operator or Transmission Network Owner and the Third Party Power Producer.
  - (ii) The Regulator shall determine the compensation (if any) of Power Producers providing Ancillary Services.
- (e) Technical Requirements for Power Producers Providing Ancillary Services
  - (i) A Power Producer providing Frequency Regulating Reserve shall be capable of varying its output up or down in response to a frequency signal or other automatic signal arranged by the System Operator. A Power Producer providing Primary Response for frequency regulation shall operate in an automatic frequency-sensitive mode (also known as governor free mode) for automatic response of the Unit's power output to changes in frequency. It must be capable of varying its output by more than 4% within 5 seconds and be able to

sustain that variation for at least 10 minutes. The Power Producer shall not override the governor free mode of a Generating Unit which is providing Primary Response unless the role of the Generating Unit has been changed in accordance with the Power Purchase Agreement or Connection Agreement or modifications to any of these agreements.

- (ii) A Power Producer providing Spinning Reserve shall be capable of ramping up to its full output power within 25 seconds from its output operating output as instructed by the System Operator and sustain that output level for at least 30 minutes in response to frequency or other automatic signal arranged by the System Operator. Frequency Control using the Secondary Response of the Power Producer shall be accomplished through Automatic Generation Control or manual adjustment of generation with specific Dispatch Instructions from the System Operator. The Power Producer shall not override the free-governor mode or Automatic Generation Control mode of a Generating Unit which is providing Secondary Response.
- (iii) A Power Producer providing Backup Reserve shall be capable of starting, synchronize and ramp up to its full output power within 15 minutes and sustain that output level for at least 8 hours.
- (iv) A Power Producer providing Voltage Control and Reactive Power Support shall be capable of varying the reactive power output in accordance with the requirements of the System Operator.
- (v) A Power Producer providing Black Start shall be capable of starting without any external power supply and capable of connecting to the Transmission Network and supplying power once started. The control mode and reference setting of speed governor and automatic voltage regulator shall be set by the System Operator.

## **5.7 Scheduling and Dispatch**

- (a) Scheduling and Dispatch Responsibilities of System Operator
  - (i) The System Operator shall be responsible for the preparation of the Generation Schedule in accordance with Economic Dispatch principles following the procedures set in this Code.
  - (ii) The System Operator is responsible for ensuring that a number of strategically located Generating Units are scheduled to provide Ancillary Services including Frequency Regulating Reserve, Spinning Reserve and Backup Reserve.
  - (iii) The System Operator shall be responsible in issuing Dispatch Instructions for the Generating Units scheduled for power generation and the Generating Units providing Ancillary Services.
- (b) Scheduling and Dispatch Responsibilities of Power Producers

- (i) A Power Producer is responsible for submitting the Capability and Availability Declaration, Generation Scheduling and Dispatch Parameters, and other data for its Generating Units to the System Operator.
  - (ii) A Power Producer providing Ancillary Services shall be responsible in ensuring that its Generating Units can provide the necessary support when instructed by the System Operator to do so.
  - (iii) A Power Producer shall implement all Dispatch Instructions from the System Operator.
- (c) Scheduling and Dispatch Responsibilities of Large Load Customers and Regulated Retailers
  - (i) Large Load Customers and Regulated Retailers are responsible for submitting their demand data for Scheduling and Dispatch to the System Operator.
  - (ii) Large Load Customers and Regulated Retailers shall implement Demand Control during an emergency situation following the instructions of the System Operator.
- (d) Scheduling and Dispatch Criteria
  - (i) The System Operator shall prepare the Generation Schedule and Dispatch the scheduled Generating Units in accordance with the following criteria:
    - (A) The generating capacity for generation shall meet the system demand and transmission losses according to Economic Dispatch;
    - (B) The generating capacity for Operating Reserve including Frequency Regulating Reserve, Spinning Reserve and Backup Reserve shall ensure the security and reliability of the power system;
    - (C) The power system shall operate in Normal State even with the loss of the largest Generating Unit;
  - (ii) The System Operator shall take into account the following factors in preparing the Generation Schedule:
    - (A) The registered parameters of Generating Units;
    - (B) The technical and operational constraints of the Transmission Network and the Generating Units;
    - (C) The need to provide Reactive Power for voltage control;
    - (D) The need to provide Operating Reserve for Frequency Control; and

- (E) Nomination of Third Parties (i.e., Power Producers and Large Load Customers) according to their bilateral power supply contracts.
- (F) The generation from Variable Renewable Energy systems shall be priority dispatched.
- (e) Scheduling and Dispatch Data
  - (i) The following Capability and Availability Data of Power Producers shall be used by the System Operator in preparing the Generation Schedule:
    - (A) Generating Unit Availability (start time and date) and Capability (gross and net);
    - (B) Generating Unit loss of capability (day, start time, end time);
    - (C) Time required to start and synchronize to the Transmission Network;
    - (D) Initial Conditions (time last synchronized or shutdown); and
    - (E) Estimated generation from Variable Renewable Energy systems.
  - (ii) The following Scheduling and Dispatch Parameters of Power Producers shall be used by the System Operator in preparing the Generation Schedule:
    - (A) Generating Unit synchronizing intervals (hot interval, Shutdown time);
    - (B) Generating Unit Shutdown Intervals;
    - (C) Generating Unit Minimum Stable Loading;
    - (D) Generating Unit Minimum Downtime;
    - (E) Generating Unit Minimum Uptime;
    - (F) Generating Unit two shifting limitation;
    - (G) Generating Unit Synchronizing Generation (Hot Synchronizing Generation, Shutdown time);
    - (H) Generating Unit ramp-up rates;
    - (I) Generating Unit ramp-down rates
    - (J) Generating Unit loading rates
    - (K) Generating Unit Load Reduction rates
  - (iii) The System Operator shall prepare a Merit Order Table of scheduled Generating Units based on Economic Dispatch using the following parameters:

- (A) Variable fuel costs of the Generating Units owned and controlled by the Regulated Retailer who is also the Transmission Network Owner;
  - (B) Variable operation and maintenance costs of the Generating Units owned and controlled by the Regulated Retailer who is also the Transmission Network Owner;
  - (C) Price, price structure and key terms including penalties in the power supply contract of IPPs and the Regulated Retailer who is also the Transmission Network Owner; and
  - (D) Generation schedule of the Third Party Power Producers to supply Third Party Regulated Retailers and Large Load Customers wheeling power through the Transmission Network.
- (iv) Variable Renewable Energy generation shall have priority dispatch in preparing the Merit Order Table.
- (f) Unit Commitment and Generation Schedule
  - (i) The System Operator shall prepare the following Generation Schedules:
    - (A) Month-Ahead Unit Commitment Schedule not later than 1200H of the last Business Day of Week 3 prior to the next Operating Month;
    - (B) Week-Ahead Generation Schedule not later than 1200H of the last Business Day of the week prior to the next Operating Week; and
    - (C) Day-Ahead Generation Schedule not later than 1200H of the day prior to the next Operating Day.
  - (ii) The Month-Ahead Unit Commitment Schedule shall consist of committed Generating Units to be scheduled based on Economic Dispatch.
  - (iii) The Week-Ahead Generation Schedule shall be considered as provisional generation schedule. The Day-Ahead Generation Schedule shall be final and will be dispatched by the System Operator.
- (g) Generation Scheduling Procedure
  - (i) Power Producers shall submit to the System Operator the Capability and Availability Declaration of its Generating Units:
    - (A) For the Month-Ahead Unit Commitment Schedule not later than the last Business Day of Week 1 of the month prior to the next Operating Month;



- (B) For the Week-Ahead Generation Schedule not later than the first Business Day of the week prior to the next Operating Week;
- (C) For the Day-Ahead Generation Schedule not later than 0900H of day prior to the next Operating Day;
- (ii) If the Power Producer's Generating Unit Capability and Availability Declaration for the next Operating Day have not been submitted within the prescribed deadline, the Generating Unit shall be excluded in the next Operating Day. If this leads to inadequate Operating Margin, the System Operator shall make best efforts to obtain increased Capability from the available Power Producers. If necessary, the System Operator may treat the excluded Generating Unit as the last priority in the Merit Order Table.
- (iii) If a scheduled Generating Unit becomes available at a different capacity, the Power Producer shall provide the System Operator, within the prescribed deadline, a revised Capability and Availability Declaration.
- (iv) If the revised Capability and Availability Declaration is submitted within the prescribed deadline, the System Operator shall take the revised Capability and Availability Declaration into account in the preparation of the final Generation Schedule.
- (v) Using the data specified in Section 5.7(e), the System Operator shall prepare a Merit Order Table based on ascending prices. The Scheduled Generating Unit that has the lowest price per kWh shall be at the top of the Merit Order Table.
- (vi) Once prepared, the Merit Order Table shall be used in determining which Generating Unit will be committed for the Generation Schedule.
- (vii) The System Operator shall use the Merit Order Table in developing the Unconstrained Generation Schedule.
- (viii) The System Operator shall determine the feasibility of the Unconstrained Generation Schedule considering the constraints in the Transmission Network and following the security and reliability criteria.
- (ix) The Unconstrained Generation Schedule shall then be adjusted by the System Operator to develop the final Constrained Generation Schedule.
- (x) After the completion of the generation scheduling process, but before the issuance of the Generation Schedule, the System Operator may make necessary adjustments to the output of the scheduling process. Such adjustments may be due to the following factors:

- (A) Changes to Generation Scheduling and Dispatch Parameters of Scheduled Generating Units;
  - (B) Changes to Demand Forecast;
  - (C) Changes to transmission line and transformer constraints;
  - (D) Changes to power system conditions which may have a material effect on the Transmission Network; and
  - (E) Changes to the scheduled daily water usage of hydroelectric Generating Plants.
- (xi) The System Operator shall issue the following Generation Schedule:
- (A) The Month-Ahead Unit Commitment Schedule for the next Operating Month not later than the last Business Day of Week 3 of the current month.
  - (B) The Week-Ahead Generation Schedule for the next Operating Week shall be issued not later than the last Business Day of the current week.
  - (C) The Day-Ahead Generation Schedule for the next Operating Day shall be issued not later than 1500H of each day.
- (xii) The final Generation Schedule shall indicate the hourly output of each Scheduled Generating Unit for each Operating Day. It shall also indicate the Generating Units that are providing specific Ancillary Services.
- (h) Load Dispatching Procedure
- (i) The Dispatch Instruction of the System Operator shall contain the following:
    - (A) The specific Generating Unit to which the instruction applies;
    - (B) The MW and MVAR output required;
    - (C) Target time of scheduled Generating Units Ramp-up and Ramp-down rates;
    - (D) Start and synchronizing time of scheduled Generating Units; and
    - (E) The Dispatch Instruction issuance time.
  - (ii) In addition to instructions relating to the dispatch of Active Power, the Dispatch Instruction may also include:
    - (A) Details of the type of reserves to be carried out by each unit, including specifications of the duration in which that reserve may be dispatched;
    - (B) An instruction for Generating Units to provide operational requirements and Ancillary Services; and

- (C) Target voltage levels or the individual Reactive Power output at the terminal of Generating Unit or at the Connection Point;
- (iii) The Dispatch Instructions shall be recorded in a logbook or other means of recording.
- (iv) The System Operator shall issue the Dispatch Instructions to all Power Producers regarding their Month-Ahead Unit Commitment Schedule, Week-Ahead Generation Schedule, and Day-Ahead Generation Schedule through an appropriate means of communication.
- (i) Dispatch Instructions for Scheduled Generating Units
  - (i) The Dispatch Instruction to a scheduled Generating Unit shall contain the scheduled time and the Power output of the Generating Unit.
  - (ii) Ramp-up and Ramp-down rates and the target time to achieve the desired output shall be in accordance with the Generation Schedule
  - (iii) The Dispatch Instruction to synchronize shall be issued by the System Operator specifying the time and sequence of synchronization.
  - (iv) The Dispatch Instruction to shutdown a Generating Unit shall specify the shutdown time.
- (j) Dispatch Instructions for Ancillary Services
  - (i) The Dispatch Instructions for Frequency Regulating Reserve shall specify whether the Generating Unit will provide Primary Response.
  - (ii) The Dispatch Instructions for Spinning and Back-up Reserve shall contain the generating capacity to be provided by the specific Generating Unit.
  - (iii) The Dispatch Instructions for Black Start shall contain the specific instruction for the Generating Units to initiate a Black Start procedure.
  - (iv) The Dispatch Instructions for emergency load reduction shall contain the generating capacity to be dropped and the time the load reduction is to be implemented.
  - (v) The Dispatch Instructions for Voltage Control shall specify the target voltage level or the maximum generation of Reactive Power.

## 5.8 Emergency Procedures

- (a) Manual of Emergency Procedures
  - (i) The System Operator shall develop, maintain, and distribute a Manual of Emergency Procedures, which lists all parties to be notified, including their business and home phone numbers, in case of an emergency.

- (ii) The manual shall also designate the location(s) where critical personnel shall report for duty.
- (b) Emergency Drills
  - (i) Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergency and Transmission Network restoration activities with the emergency and restoration procedures. The drills shall simulate realistic emergency situations.
  - (ii) A drill evaluation shall be performed and deficiencies in procedures and responses shall be identified and corrected.
- (c) Significant Incident Procedure
  - (i) Immediately following a Significant Incident, the System Operator shall create and head a Significant Incident Investigation Group with members from the Transmission Network Owner, Power Producers, Regulated Retailers and Large Load Customer to investigate the Significant Incident.
  - (ii) The Significant Incident Investigation Group shall submit to the System Operator a written Significant Incident Investigation Report detailing all the information, findings, and recommendations regarding the Significant Incident. After its review and acceptance of the Significant Incident Investigation Report, the final report shall be submitted to the Technical Regulator.
  - (iii) The following information shall be included in the written report following the investigation of the Significant Incident:
    - (A) Date, time and duration of the Significant Incident;
    - (B) Location of the Significant Incident;
    - (C) Equipment directly involved and not merely affected by the Event;
    - (D) Demand (in MW) and generation (in MW) interrupted and the duration of the Interruption;
    - (E) Description of the Significant Incident including sequence of events;
    - (F) Findings on the causes and who are responsible for the Significant Incident; and
    - (G) Recommendations on how to eliminate or minimize the same incident to happen again or to minimize the consequences and damages due to the Significant Incident.
- (d) Black Start and Dead Bus Access Procedure

- (i) If a Significant Incident resulted in a Partial System Blackout or a Total System Blackout, the System Operator shall inform the Users that it intends to implement a Black Start.
- (ii) The System Operator shall issue instructions for the Generating Plants with Black Start and Dead Bus Access Capability to initiate the Start-Up.
- (iii) Upon receipt of the instruction from the System Operator, Generating Plants providing Black Start shall Start-Up immediately to energize a part of the Transmission Network and/or synchronize to the Transmission Network.
- (iv) The overall strategy in the restoration of the Transmission Network after a Total System Blackout shall, in general, include the following:
  - (A) Overlapping phases of Blackout restoration of Island Grid;
  - (B) Step-by-step integration of the Island Grid into larger subsystems; and
  - (C) Eventual restoration of the Transmission Network.
- (v) When parts of the Transmission Network are not synchronized with each other, the System Operator shall instruct Users to regulate generation and/or demand to enable the isolated Island Grid to be resynchronized.
- (vi) If a part of the Transmission Network is not connected to the rest of the Transmission Network, but there is no Blackout in that part of the Transmission Network, the System Operator shall undertake the resynchronization of that part to the Transmission Network.
- (vii) The System Operator shall inform the Transmission Network Users, after completing the Black Start procedure and the restoration of the Transmission Network, that the Blackout no longer exists and that the Transmission Network is back to the Normal State.

## 5.9 Safety Coordination

- (a) Safety Rules and Safety Precautions
  - (i) The Transmission Network Owner and Users shall adopt and use a set of Safety Rules for implementing Safety Precautions on HV Equipment which shall govern any work or testing on the Transmission Network or the User System.
  - (ii) Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the Transmission Network Owner and the User.
  - (iii) The User (or Transmission Network Owner) shall seek authority from the Transmission Network Owner (or the User) if it wishes to access any Transmission Network Owner (or User) Equipment.

- (iv) Where work or testing is to be carried out on the Transmission Network and the User becomes aware that Safety Precautions are also required on the System of other Users, the Transmission Network Owner shall be promptly informed of the required Safety Precautions on the System of the other Users. The Transmission Network Owner shall ensure that Safety Precautions are coordinated and implemented on the Transmission Network and all User Systems.
- (b) Safety Coordinator
  - (i) The Transmission Network Owner and the User shall assign a Safety Coordinator who shall be responsible for the coordination of Safety Precautions on the HV Equipment at their respective sides of the Connection Point.
  - (ii) The Safety Coordinator requesting that a Safety Precaution be applied on the system of the other party shall be referred to as the Requesting Safety Coordinator while the Safety Coordinator that will implement the requested Safety Precaution shall be referred to as the Implementing Safety Coordinator.
  - (iii) If work or testing is to be carried out on the Transmission Network (or the User System) that requires Safety Precautions on the HV and EHV Equipment of the User System (or the Transmission Network), the Requesting Safety Coordinator shall contact the Implementing Safety Coordinator to coordinate the necessary Safety Precautions.
  - (iv) When a Safety Precaution becomes ineffective, the concerned Safety Coordinator shall inform the other Safety Coordinator about it without delay stating the reason why the Safety Precaution has lost its integrity.
- (c) Safety Logs and Record of Inter-System Safety Precautions
  - (i) The Transmission Network Owner and the User shall maintain Safety Logs to record, in chronological order, all messages relating to Safety Coordination. The Safety Logs shall be retained for at least one (1) year.
  - (ii) The Transmission Network Owner shall establish a record of Inter-System Safety Precautions to be used by the Requesting Safety Coordinator and the Implementing Safety Coordinator in coordinating the Safety Precautions on HV Equipment. The record of Inter-System Safety Precautions shall contain the following information:
    - (A) Site and Equipment Identification of HV Equipment where Safety Precaution is to be established or has been established;

- (B) Location and the means of implementation of the Safety Precaution;
  - (C) Confirmation of the Safety Coordinator that the Safety Precaution has been established; and
  - (D) Confirmation of the Safety Coordinator that the Safety Precaution is no longer needed and has been cancelled.
- (d) Location of Safety Precautions
  - (i) When work or testing is to be carried out on the Transmission Network (or the User System) and Safety Precautions are required on the User System (or the Transmission Network), the Requesting Safety Coordinator shall contact the concerned Implementing Safety Coordinator to agree on the location(s) at which the Safety Precautions will be implemented or applied. The Requesting Safety Coordinator shall specify the proposed locations at which Isolation and/or Grounding are to be established.
  - (ii) In the case of Isolation, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:
    - (A) The Identification of each Point of Isolation; and
    - (B) The means of implementing Isolation.
  - (iii) In the case of Grounding, the Implementing Safety Coordinator shall promptly notify the Requesting Safety Coordinator of the following:
    - (A) The Identification of each Point of Grounding; and
    - (B) The means of implementing Grounding.
- (e) Implementation of Safety Precautions
  - (i) Once the location(s) of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.
  - (ii) Isolation shall be implemented by a disconnect switch that is secured in an open position by a lock and affixing a Safety Tag to it;
  - (iii) Grounding shall be implemented by a Grounding switch secured in a closed position by a lock and affixing a Safety Tag to it or by such other method in accordance with the Local Safety Instructions of the Transmission Network Owner or the User, as the case may be
  - (iv) The Implementing Safety Coordinator, after establishing the required Isolation and/or Grounding in all locations, shall notify the Requesting Safety Coordinator that the required Isolation and/or Grounding has been implemented.
  - (v) After receiving the confirmation of Isolation and/or Grounding, the Requesting Safety Coordinator shall inform the Implementing Safety

Coordinator of the establishment of Isolation and/or Grounding on his System

- (f) Authorization of Testing
  - (i) If the Requesting Safety Coordinator wishes to authorize a test on HV, he shall only do so after the following procedures have been implemented:
    - (A) Confirmation is obtained from the Implementing Safety Coordinator that no person is working on or testing, or has been authorized to work on or test, any part of his System within the Points of Isolation identified on the form;
    - (B) All Safety Precautions other than the current Safety Precautions have been cancelled; and
    - (C) The Implementing Safety Coordinator agrees with him on the conduct of testing in that part of the System.
- (g) Cancellation of Safety Precautions
  - (i) When the Requesting Safety Coordinator decides that Safety Precautions are no longer required, he shall contact the Implementing Safety Coordinator and inform him that the Safety Precautions are no longer required.
  - (ii) Both coordinators shall then cancel the Safety Precautions.

## 6. Implementation and Enforcement

### 6.1 Governance of the Grid Code

- (a) Governed by the Regulator
 

The Grid Code must be governed by the Regulator, who may make amendments and/or variations from time to time, but any such amendments and/or variations must not be inconsistent with the objectives set out in Section 1.4.
- (b) Process for amendments and/or variations
 

No variation may be made to this Code unless:

  - (i) At least 40 Business Days prior to any amendment and/or variation taking effect:
    - (A) The Regulator has published a notice describing the proposed amendment and/or variation in both the National Gazette and a daily newspapers circulating nationally and inviting the making of submissions in relation to the proposed amendment and/or variation not less than 20 Business Days after the date of publication of that notice.



- (B) The Regulator has provided a notice to the Minister responsible for the Electricity Industry Act describing the proposed amendment and/or variation.
  - (C) The Regulator has made available, for inspection or purchase by the public, copies of the precise form of the proposed amendment and/or variation.
- (ii) The Regulator has considered such submissions in relation to the proposed amendments and/or variations it receives under (i) above.
- (c) **Changes to Regulatory Contracts and Licences**  
 The Regulator must ensure that any material changes to the Regulatory Contracts and Licences of Transmission Network Operators and Regulated Retailers must be reflected in this Code, so long as they are consistent with the principles of the Electricity Industry Act, the ICCA Act, the Regulatory Contract, the TPA Code and this Code.
- (d) **Version that Applies**  
 If an amendment and/or a variation is made to this Code, the version of this Code that must apply is the version that was in place at the time the equipment in the Transmission Network and User System except for:
  - (A) The equipment that may endanger the safety of personnel and the public;
  - (B) The equipment that materially affects or degrade the security and reliability of the Grid; or
  - (C) The equipment that materially affects the economic operation of the Grid.
- (e) **Costs Recovery due to Amendment to the Grid Code**  
 If an amendment and/or a variation is made to this Code which will require the Transmission Network and/or User System to be modified in compliance with Section 6.1 (d), The Transmission Network Owners shall submit to the Regulator for approval the proposed modification of the Transmission Network and/or User System and its proposal for cost recovery.

## 6.2 Compliance to the Grid Code

- (a) **Statement of Compliance and Compliance Plan**
  - (i) The Transmission Network Owner, System Operator, Power Producers and Regulated Retailers shall assess the compliance of their respective equipment, operating procedures and management systems to the technical and performance standards and requirements of this Code.
  - (ii) The Transmission Network Owners, Power Producers and Regulated Retailers shall submit to the Regulator within six (6) months from the effectivity of this Code for approval of the

- Statement of Compliance and Compliance Plan for any equipment, operating procedures and management systems that is not compliant with this Code.
- (iii) The Technical Regulator shall prepare a Compliance Plan to establish its organization, management systems and tools needed to implement this Code.
  - (iv) The Compliance Plan of the Transmission Network Owner, Power Producers and Regulated Retailers shall be prepared in accordance with the planning criteria and procedures prescribed by this Code.
  - (v) The Compliance Plan of the Transmission Network Owner shall form part of the Transmission Development Plan. The Compliance Plan of the Regulated Retailer shall form part of the Power Supply Plan and/or Distribution Development Plan.
  - (vi) The Compliance Plan shall indicate the following phases of Grid Code Implementation:
    - (A) Phase 1: Compliance Projects and/or Activities to be implemented within One (1) year. This shall include all data to be gathered and operating procedures such as the Transmission Connection Service Procedure, planning procedures, and operation and control procedures;
    - (B) Phase 2: Compliance Projects and/or Activities to be implemented within five (5) years. This shall include the management systems and tools (for power system analysis, planning, forecasting, scheduling and dispatch, reliability and security assessment, and performance monitoring and reporting) to implement the Grid Code and the replacement, modification or upgrading of equipment (including protection system equipment such as circuit breakers, relays and instrument transformers, SCADA/EMS and communication system, and metering equipment such as meters, CTs, VTs, data loggers and communication system) to comply with the Grid Code. The Transmission
    - (C) Phase 3: Compliance Projects and/or Activities to be implemented within ten (10) years. This shall include the replacement or modification of capital-intensive equipment to comply with the Grid Code such as Generating Units and Transformers;
  - (vii) The Compliance Plan of Transmission Network Owners, Power Producers and Regulated Retailers shall be reviewed by the Technical Regulator for its recommendation to the Regulator.
- (b) Equipment for New Connection and Modification of Existing Connection

- (i) Equipment for new connection and modification of existing connection to the Transmission Network shall comply with the requirements of this Code.
- (ii) Where it is uneconomical to replace existing equipment for the modification of existing connection to the Transmission Network, the Third Party Users (Power Producers, Other Retailers, Large Load Customers) may submit a compliance schedule to be considered by the Transmission Network Owner who shall in turn submit to the Regulator its proposal for compliance of Third Party Users.
- (c) Exemption of Existing Equipment
  - (i) Existing equipment may be exempted by the Regulator from compliance if the continued operation of the equipment does not:
    - (A) Endanger the safety of personnel and the public;
    - (B) Materially affects or degrade the security and reliability of the Grid; and
    - (C) Materially affects the economic operation of the Grid.
- (d) Compliance Monitoring and Assessment by the Technical Regulator
  - (i) The Within six (6) months from effectivity of this Code, the Technical Regulator shall establish the procedures and requirements for submitting reports and physical inspection to monitor and assess the performance and compliance of the Transmission Network Owner.

### 6.3 Dispute Resolution

- (a) Notification of dispute
  - (i) A Transmission Network Owner, Power Producer, Regulated Retailer, or Large Load Customer ("disputing parties") may notify the Regulator that a dispute exists related to the implementation and enforcement of this Code and provide relevant information, including any commercial claims and agreements.
  - (ii) The Regulator must notify the other disputing parties that a dispute has been raised.
- (b) Confidential information
  - (i) A disputing party may request that information related to the dispute be kept confidential.
  - (ii) The Regulator will inform the other disputing party that such a request has been made, ask if there are any objections, will consider the request and comply with it considers the request to be in the interests of resolving the dispute and the principles set out in this Code.
- (c) Involvement of Technical Regulator

If the Regulator considers that there are technical aspects to the dispute that relate to the Grid Code or any other decision made by the Technical Regulator, the Regulator may request that the Technical Regulator be involved in arbitrating and making a determination on the dispute.

(d) Withdrawal of dispute

The party that notified the Regulator of the dispute may withdraw the notification at any time before the Regulator makes its final determination, with either the agreement of the other disputing party, or if the other disputing party does not agree, the Regulator.

(e) Negotiations

If the Regulator considers that a process of negotiation is likely to facilitate a resolution to the dispute, it must request the disputing parties to enter into the negotiations and set out a procedure for such negotiations and a date by which they must be concluded.

(f) Arbitration

(i) If the Regulator considers that a process of negotiation is unlikely to deliver a resolution to the dispute or negotiations have failed to reach a resolution by the date specified by the Regulator then it must move to a process of arbitration, conducted by the Regulator with, if required, the assistance of the Technical Regulator.

(ii) When conducting an arbitration, the Regulator may request any information from the disputing parties that it considers will assist it in making its determination.

(g) Arbitration hearing

(i) The Regulator may (but is not required) to hold one or more hearings in arbitrating any dispute. In an arbitration hearing, the Regulator:

- (A) Is not bound by technicalities, legal forms or rules of evidence; and
- (B) Must act as speedily as a proper consideration of the dispute allows, having regard to the need to carefully and quickly inquire into and investigate the dispute and all matters affecting the merits, and fair settlement, of the dispute.
- (C) May inform itself of any matter relevant to the dispute in any way it thinks appropriate.
- (D) May enable a party to attend by video-conference or audio-conference if that party is unable to attend in person; and
- (E) Must give a party at least 7 days' notice of any hearing.

- (ii) The Regulator may charge the disputing parties to arbitration for its reasonable costs in conducting the arbitration and apportion the charge between the parties.
- (h) Matters taken into account by the Regulator

The Regulator must take the following matters into account in making its determination following an arbitration process:

  - (A) The extent to which the determination is likely to further the achievement of the objectives of this Code.
  - (B) The general principles contained in this Code.
  - (C) The legitimate business interests of the Regulated Retailer/Transmission Network Operator, and their investment in facilities used to provide access.
  - (D) The interests of all persons who use services provided by the Regulated Retail/Transmission Network Operator and Third Party.
  - (E) The operational and technical requirements necessary to protect the safe and reliable operation of the electricity system.
  - (F) Any other matters that it thinks are relevant.
- (i) Interim determination
  - (i) The Regulator may make a written interim determination on the dispute while arbitration continues, where it considers that failure to do so may cause irreparable damage or costs that cannot be compensated to the Regulated Retail/Transmission Network Operator or the Third Party or any other affected party. The interim determination is in force until a notification of the dispute is withdrawn or the Regulator makes a final determination.
  - (ii) The interim determination may not be backdated but may be revoked or varied by the Regulator.
- (j) Final determination
  - (i) The Regulator must use reasonable endeavours to make a final determination within 18 months of the date on which it receives notification of an access dispute.
  - (ii) When the Regulator makes a final determination, it must give the disputing parties its reasons for making the final determination.
  - (iii) The final determination may deal with any matter relating to access by the Third Party including matters that were not the basis for notification of the dispute.
  - (iv) Before making a final determination, the Regulator shall give a draft of the final determination to the disputing parties, provide those

parties with at least 14 days to make written submissions, and must have regard to those written submissions.

(v) All parties to the arbitration must comply with the final determination

(k) Termination of arbitration

The Regulator may at any time terminate an arbitration (without making a determination) if it thinks that:

- (A) The notification of the dispute was vexatious.
- (B) The subject matter of the dispute is trivial, misconceived or lacking in substance.
- (C) A party to the arbitration of the dispute has not engaged in negotiations in good faith.
- (D) Access should continue to be governed by existing arrangements and agreements between the Regulated Retailer/Transmission Network Owner and the Third Party.
- (E) The arbitration is not likely to further the objectives of this Code.
- (F) The services provided by the Third Party are not considered to be of significant social and/or economic importance.
- (G) The Third Party lacks the financial and/or technical capacity to be able to make use of any access it may be granted.

(l) Appeal of decision by Regulator

Decisions made by the Regulator may be appealed to an Appeals Panel as per Section 43 of the *Independent Consumer and Competition Commission Act 2002*.

---

**ANNEXES**

---

---

## Annex 1: Protection Requirements

---

### A1.1 Generator Protection

- (m) Protective Relaying Requirements
  - (i) Generators shall have the following protective relaying
    - (A) Stator differential protection
    - (B) Overvoltage protection
    - (C) Undervoltage protection
    - (D) Reverse power protection
    - (E) Unbalanced loading protection
    - (F) Loss of Excitation Protection
    - (G) Underfrequency protection
  - (ii) Generator connected to the grid thorough step-up transformer shall, in addition to the protection above, be provided with overall (generator-transformer) differential protection and high voltage overcurrent (phase and earth-fault) protection and surge diversion.

### A1.2 Transmission Line Protection

- (a) Simple Transmission Circuits
  - (i) Overhead transmission lines and underground cables shall be protected against all types of faults: phase-to-phase, phase-to-ground, two phase-to-ground, and three phase.
  - (ii) The protection shall discriminate between short circuit and load current to permit loading of lines to maximum capacity while still ensuring that all faults will be detected.
  - (iii) High-speed primary relaying shall simultaneously trip all phases at all terminals of the line for all multi-phase internal faults.
  - (iv) Distance relaying with three (3) zones shall be used to protect the transmission lines and underground cables. Time-overcurrent relays may be employed as back-up protection in addition to the back-up provided by Zone 2 and Zone 3 of the distance relaying.
- (b) Complex Transmission Circuits
  - (i) Distance protection for parallel transmission lines (double circuits) shall consider the following problems:
    - (A) Current reversal in a healthy line when a fault is cleared sequentially on one circuit with generation sources at both ends of the circuit.



- (B) Under-reach for the zones set to reach into the affected line when a fault occurs on a line that lies beyond the remote terminal end of a parallel line circuit.
- (C) Distance relay behavior with earth faults on the protected line and on parallel line
- (D) Distance relay behavior with single-circuit operation
- (ii) Multi-ended circuits having three or more terminals shall use Unit Protection scheme distance relaying

### **A1.3 Transformer Protection**

- (a) High Speed Differential Protection
  - (i) Transformers in the transmission network shall be provided with high-speed differential protection.
  - (ii) Transformer protection shall be capable of distinguishing between fault current and magnetizing in-rush current. When in-rush or heavy external fault currents exist, means shall be provided to prevent misoperation of differential relays due to instrument transformer errors.
- (b) Time-Overcurrent Protection
  - (i) Transformers shall be protected against phase and earth faults by time-overcurrent relays
  - (ii) Time-overcurrent relays shall be coordinated with downstream and upstream protective devices
- (c) Other Protection of Transformer
  - (i) Gas analysis, pressure, and temperature relays may be used for tripping or alarming where it is practical and expedient.

### **A1.4 Bus Protection**

- (a) High-Speed Differential Protection
  - (i) All generating plant and bulk power station and Transmission Substation buses shall be provided with high-speed differential protection. This protection shall discriminate between faults on the bus from those which occurs external to the protected zone.
  - (ii) Bus fault clearing shall be faster than the connected line backup clearing times.
  - (iii) Means shall be provided to prevent misoperation of the relays due to instrument transformer errors.

### **A1.5 Distribution Feeder Protection**

- (a) Overcurrent Protection at Substation

- 
- (i) Distribution Feeder shall have the following protection at the substation:
    - (A) Phase-fault protection; and
    - (B) Earth-fault protection
  - (ii) Protection shall be provided by circuit breakers operated by relays.
- (b) Overcurrent Protection along Feeders
- (i) Distribution Feeder shall have overcurrent protection at the tapping point of lateral circuits using Automatic Circuit Reclosers and/or Distribution Fuse Cut-outs
  - (ii) Automatic Circuit Reclosers and Sectionalizers may be installed to sectionalize the main distribution feeder.
-

---

## Annex 2: Planning Data

---

### A2.1 Standard Planning Data

- (a) Historical Energy and Demand
  - (i) The User shall provide the Transmission Network Owner its actual monthly peak and energy demand at each Connection Point for the immediate past year.
  - (ii) The User shall also provide when required by the Transmission Network Owner the actual hourly load profiles for a typical weekday, weekend, and holiday.
- (b) Energy and Demand Forecast
  - (i) The User shall provide the Transmission Network Owner with its energy and demand forecasts at each Connection Point for the five (5) succeeding years.
  - (ii) The Forecast Data for the first year shall include monthly Energy and demand forecasts, while the remaining four years shall include only the annual energy and demand forecasts.
  - (iii) The User shall also provide when required by the Transmission Network Owner the forecasted hourly load profiles for a typical weekday, weekend, and holiday.
  - (iv) If the User System is connected to the Transmission Network at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the Energy and Demand forecasts for each bus section shall be separately stated.
- (c) User System Data
  - (i) The User shall provide the Electrical Diagrams and Connection Point Drawings of the User System and the Connection Point. The diagrams and drawings shall indicate the quantities, ratings, and operating parameters of the following:
    - (A) Equipment (e.g., Generating Units, power transformers, and circuit breakers);
    - (B) Electrical circuits (e.g., overhead lines and underground cables);
    - (C) Substation bus arrangements;
    - (D) Grounding arrangements;
    - (E) Phasing arrangements; and
    - (F) Switching facilities.

- (ii) The User shall provide the values of the following circuit parameters of the overhead lines and/or underground cables from the User System substation to the Connection Point in the Grid:
  - (A) Rated and operating voltage (kV);
  - (B) Positive sequence resistance and reactance (ohm);
  - (C) Positive sequence shunt susceptance (Siemens or ohm-1);
  - (D) Zero sequence resistance and reactance (ohm); and
  - (E) Zero sequence susceptance (Siemens or ohm-1).
- (iii) If the User System is connected to the Transmission Network through a step-up transformer, the following data for the power transformers shall be provided:
  - (A) Rated MVA;
  - (B) Rated voltages (kV);
  - (C) Winding arrangement;
  - (D) Positive sequence resistance and reactance (at max, min, and nominal tap);
  - (E) Zero sequence reactance for three-legged core type transformer;
  - (F) Tap changer range, step size and type (on-load or off-load); and
  - (G) Basic Lightning Impulse Insulation (BIL) Level (kV).
- (iv) The User shall provide the following information for the switchgear, including circuit breakers, load break switches, and disconnect switches at the Connection Point and at the substation of the User:
  - (A) Rated voltage (kV);
  - (B) Rated current (A);
  - (C) Rated symmetrical RMS short-circuit current (kA); and
  - (D) Basic Lightning Impulse Insulation Level (kV).
- (v) The User shall provide the details of its System Grounding. This shall include the rated capacity and impedances of the Grounding Equipment.
- (vi) The User shall provide the data on independently-switched Reactive Power compensation equipment at the Connection Point and/or at the substation of the User System. This shall include the following information:
  - (A) Rated Capacity (MVAR);
  - (B) Rated Voltage (kV);

- (C) Type (e.g., shunt inductor, shunt capacitor, Static VAR Compensator); and
  - (D) Operation and control details (e.g. fixed or variable, automatic, or manual).
- (d) Generating Unit Data
  - (i) The Power Producer shall provide the Transmission Network Owner with data relating to the Generating Units of its power plant.
  - (ii) The following information shall be provided for the Generating Units of each Generating Plant:
    - (A) Rated Capacity (MVA and MW);
    - (B) Rated Voltage (kV);
    - (C) Type of Generating Unit and expected running mode(s);
    - (D) Direct axis subtransient reactance (percent); and
    - (E) Rated capacity, voltage, and impedance of the Generating Unit's step-up transformer.
  - (iii) If the Generating Unit is connected to the Transmission Network at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the bus section to which each Generating Unit is connected shall be identified.

## A2.2 Detailed Planning Data

- (a) Generating Unit Data
  - (i) The following additional information shall be provided for the Generating Units of each Generating Plant:
    - (A) Derated Capacity (MW) on a monthly basis if applicable;
    - (B) Additional capacity (MW) obtainable from Generating Units in excess of Net Declared Capability;
    - (C) Minimum Stable Loading (MW);
    - (D) Reactive Power Capability Curve;
    - (E) Stator armature resistance;
    - (F) Direct axis synchronous, transient, and subtransient reactances;
    - (G) Quadrature axis synchronous, transient, and subtransient reactances;
    - (H) Direct axis transient and subtransient time constants;
    - (I) Quadrature axis transient and subtransient time constants;
    - (J) Turbine and Generating Unit inertia constant (MWsec/MVA);

- (K) Rated field current (amps) at rated MW and MVAR output and at rated terminal voltage; and
- (L) Short circuit and open circuit characteristic curves.
- (b) Excitation System Data
  - (i) The following information for Step-up Transformers shall be provided for each Generating Unit:
    - (A) Rated MVA;
    - (B) Rated Frequency (Hz);
    - (C) Rated voltage (kV);
    - (D) Voltage ratio;
    - (E) Positive sequence reactance (maximum, minimum, and nominal tap);
    - (F) Positive sequence resistance (maximum, minimum, and nominal tap);
    - (G) Zero sequence reactance;
    - (H) Tap changer range;
    - (I) Tap changer step size; and
    - (J) Tap changer type: on load (automatic or manual) or off-load.
  - (ii) The following excitation control system parameters shall be provided for each Generating Unit:
    - (A) DC gain of Excitation Loop;
    - (B) Rated field voltage;
    - (C) Maximum field voltage;
    - (D) Minimum field voltage;
    - (E) Maximum rate of change of field voltage (rising);
    - (F) Maximum rate of change of field voltage (falling);
    - (G) Details of Excitation Loop described in diagram form showing transfer functions of individual elements;
    - (H) Dynamic characteristics of over excitation limiter; and
    - (I) Dynamic characteristics of under excitation limiter.
- (c) Speed-Governing Data
  - (i) The following speed-governing system parameters shall be provided for each Generating Unit:
    - (A) Governor average gain;
    - (B) Speeder motor setting range;
    - (C) Speed droop characteristic curve;

- (D) Time constant of steam or fuel governor valve or water column inertia;
  - (E) Governor valve opening limits;
  - (F) Governor valve rate limits; and
  - (G) Time constant of turbine.
- (d) Flexibility Performance Data
  - (i) The following plant flexibility performance data shall be submitted for each Generating Plant:
    - (A) Rate of loading following shutdown (Generating Unit and Generating Plant);
    - (B) Block load following synchronizing;
    - (C) Rate of Load Reduction from normal rated MW;
    - (D) Regulating range; and
    - (E) Load rejection capability while still synchronized and able to supply load.
- (e) Auxillary Demand Data
  - (i) The following auxiliary Demand data shall be submitted:
    - (A) Normal unit-supplied auxiliary load for each Generating Unit at rated MW output; and
    - (B) Each Generating Plant auxiliary Load other than those in A.2.2 (e) (i) (A) above and where the station auxiliary Load is supplied from the Transmission Network.