THE ZAMBIAN GRID CODE

October 2006

Enquiries: Energy Regulation Board

CONTENTS

ACKNOWLEDGEMENTS

This Grid Code, although uniquely Zambian, has drawn on the following internationally available grid codes and documents:

a. The South African Grid code
b. The National Grid code of the United Kingdom
c. The Belgian Grid Code
d. The Australian Grid Code
e. The Philippine Grid Code
f. The Ugandan Grid Code
g. Performance of Generating Plant – A report by World Energy Council (October 2001).
h. SAPP documents
i. Relevant Zambian Standards

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PREFACE

1 Industry Reforms

In 1995 the Government of the Republic of Zambia (GRZ) liberalised the *Electricity Supply Industry (ESI)* in Zambia with the promulgation of the Electricity Act (1995), which removed Zesco's statutory monopoly in the industry, and the Energy Regulation Act (1995) which formed a regulator for the energy sector. As a result of this legislation, other entities are now permitted by law to participate in the *ESI*. In order to ensure that the goals of the liberalisation, primarily enhanced efficiency and more rapid electrification, are achieved, it is imperative that various arrangements are put in place that outline how the various parties in the *ESI* are expected to interact. The *ZGC* is one such arrangement and its main aim is to facilitate open and non-discriminatory access to the *Transmission System*.

The regulator of the Zambian *ESI*, the *Energy Regulation Board (ERB)* anchored the development of the *ZGC* through a consultative stakeholder process. This process has seen the creation of a *GCTC* that is effectively a body constituted of industry participants and *stakeholders* who have the function of reviewing proposed changes to the *ZGC* and making recommendations to the *ERB* on the *ZGC*.

2 Industry Structure

The Zambian *Electricity Supply Industry (ESI)* presently consists of three major market players namely Zesco Ltd, Copperbelt Energy Corporation plc and Lunsemfwa Hydro Power Company ltd.

By October 2005, the three entities were licensed by the *ERB* as follows:

a. ZESCO Limited

Licensed as a *generator*, national provider of *transmission* and system operation services, national provider of *distribution* services and national provider of electricity supply services.

b. Lunsemfwa Hydro Power Company (LHPC) Ltd

Licensed as a *generator* and provider of electricity *distribution* and supply services to some industries in Kabwe.

c. Copperbelt Energy Corporation (CEC) Plc

Licensed as a *generator*, provider of *transmission*, *distribution* and electricity supply services on the Copperbelt.

All the major *power stations* in Zambia are located in the southern part of the country**.** The major power stations are linked to Leopards Hill *substation* in Lusaka, which in turn is connected to the Copperbelt load via Kabwe step-down *substation*.

System operation is coordinated by the Zesco National Control Center in conjunction with the various control centers. The National Control Center uses a SCADA (Supervisory, Control and Data Acquisition) system, which covers 24 stations, which include four (4) *Power Stations* and twenty (20) *Substations*.

CEC operates a *Regional Control Center* for its system on the Copperbelt. Zesco and Lunsemfwa Hydro Power Company operate control rooms at their *power stations*.

3 *ZGC* Scope

The *ZGC* is applicable to the current structure of the Zambian *ESI,* but will be updated as the industry evolves.

The elements of the industry structure for which the *ZGC* therefore makes provision are the following:

a. An *SO* and the national *Transmission Network Service-Provider (TNSP)*.

b. A *Regional Operator* and independent *TNSP,* roles that are currently with CEC.

c. A generation sector consisting of Zesco-owned *generators* and *independent generators*.

d. A distribution sector.

e. *End-use customers*, buying directly from a generator or being supplied via a supplier;

f. International trading via the interconnectors with other countries, and in line with the *SAPP* rules.

4 *ZGC* objectives

The *ZGC* is intended to establish the reciprocal obligations of industry *participants* around the use of the *TS* and operation of the *IPS*.

The *Grid code* shall ensure the following:

a. That, accountabilities of all *parties* are defined for the provision of *open access* to the *TS*.

b. That, minimum technical requirements are defined for *customers* connecting to the *TS*.

c. That, minimum technical requirements are defined for *service-providers*.

d. That, the *SO* obligations are defined to ensure the integrity of the *IPS*.

e. That, obligations of *participants* are defined for the safe and efficient operation of the *TS*.

f. That the relevant information is made available to and by the industry *participants*.

g. That the major technical cost drivers and pricing principles of the *service-providers* are transparent.

h. The responsibility of the *service-providers* under this *Grid Code* shall be -

i. to show no interest in whose product is being transported;

j. to ensure that investments are made within the requirements of the *Grid Code*;

k. to provide access on agreed standard terms, to all parties wishing to connect to or use the *TS.*

The *ZGC* defines what is understood by non-discrimination through the definition of consistent and transparent principles, criteria and procedures.

5 *ZGC* overview

In order to achieve the above objectives, the *ZGC* has the following sections:

a. A *Governance Code*, detailing all aspects of *Grid Code* administration and review.

b. A *Network Code*, focusing on *TNSPs* and *customer* technical network requirements. It is broken down into sections defining connection conditions (for *generators*, *distributors* and *end-use customers*), defining technical design requirements applicable to the *service-providers* and finally defining the *transmission* investment process and methodology.

c. A *System Operation Code*, defining the responsibilities of the *SO* and its *customers.*

d. A *Metering Code*, specifying the requirements for tariff *metering* at the *TS* interface level.

e. A *Transmission Tariff Code*, specifying the objectives and structure of the *transmission* tariff and the methodologies employed.

f. An *Information Exchange Code*, specifying the information requirements of all parties.

6 Notices

Communication with the *Secretariat* in respect of the normal operations of this *Grid Code* shall be sent to the following chosen address:

Grid Code Secretariat
…………………………
…………………………
…………………………

Communication with other *participants* shall be sent to the following addresses:

Participant 1:
……………………………………
……………………………………
……………………………………

Participant 2:
……………………………………
………………………………………
………………………………………

Participant n-1:
……………………………………
……………………………………
………………………………………

Participant n:
……………………………………
………………………………………
………………………………………

Any notice given in terms of this *Grid Code* shall be in writing and shall -

a. if delivered by hand, be deemed to have been duly received by the addressee on the date of delivery and a receipt will have to be produced as proof of delivery;

b. if posted by pre-paid registered post, be deemed to have been received by the addressee 14 *days* after the date of such posting;

c. if successfully transmitted by facsimile, be deemed to have been received by the addressee one *day* after dispatch.

7 Contracting

The *ZGC* shall comprise one of the standard documents that form part of the contract between *service-providers* and each of their *customers*.

PART 1 – ACRONYMS AND DEFINITIONS

1 ACRONYMS / ABBREVIATIONS

Note: Standard SI symbols and abbreviations are used throughout the *ZGC* without re-definition here.

AAICG	Annual Average Incremental Cost of Generation
AC:	Alternating Current
ACE:	Area Control Error
AGC:	Automatic Generation Control
ARC:	Auto Re-close
AVR:	Automatic Voltage Regulator
A-U/F-LS:	Automatic Under-Frequency Load Shedding
B/U:	Back-Up
BSA:	Bulk Supply Agreement
CAPEX:	Capital Expenditure
CBM:	Condition Based Maintenance
CT:	Current Transformer
DC:	Direct Current
DCF:	Discounted Cash Flow
DCS:	Distributed Control System
EENS:	Expected Energy Not Served
E/F:	Earth Fault
ERB:	Energy Regulation Board
ERLF:	External Reliability Loss Factor
FACTS:	Flexible AC *Transmission System*
F/L:	Fault Level
GAV:	Gross Asset Value
GCR:	Grid Code Requirement
GPS	Global Positioning System
HV:	High Voltage
HVDC:	High Voltage Direct Current
Hz:	Hertz
IDMT:	Inverse Definite Minimum Time
IEC:	International Electro-technical Commission
IEEE:	Institute of Electrical and Electronic Engineers
IPS:	Interconnected Power System

LV:	Low Voltage
MCR:	Maximum Continuous Rating
MV:	Medium Voltage
MVA:	Mega-Volt-Ampere
MVAr:	Mega-Volt-ampere reactive
MW:	Mega-Watt
MEWD:	Ministry of Energy and Water Development
NAV	Net Asset Value
NCR:	Non-Conformance Report
NERC:	North American Electricity Reliability Council
NPV:	Net Present Value
OEM:	Original Equipment Manufacturer
O&M:	Operation and Maintenance
OST:	Out-of-Step Tripping
O/C:	Over-Current
PCC:	Point of Common Coupling
PCLF:	Planned Capability Loss Factor
PCS:	Process Control System
Protection	Grid Protection
PSA:	Power Supply Agreement
PSB:	Power Swing Blocking
p.u.:	per unit
QOS:	Quality of Supply
RTU:	Remote Terminal Unit
REA:	Rural Electrification Authority
RO:	Regional Operator
SAPP:	Southern African Power Pool
SCADA:	Supervisory Control And Data Acquisition
SCS:	Substation Control System
SFR:	Start-Up Failure Rate
SO:	System Operator
SSR:	Sub-synchronous Resonance
STATCON:	Static Condenser
SVC:	Static VAR Compensator
TCSC:	Thyristor Controlled Series Capacitor
TNSP:	Transmission Network Service-Provider
TS:	Transmission System
Tx:	Transformer

UCF:	Unit Capability Factor
UCLF:	Unplanned Capability Loss Factor
Um, Umax:	Maximum rated voltage
Un:	Nominal voltage
UPC:	Unified Power Controller
VT:	Voltage Transformer
ZGC:	Zambian Grid Code
ZS:	Zambian Standard

2 DEFINITIONS

All italicized words and expressions in the *ZGC* shall bear the following meaning:

Academia
Research and teaching staff of Institutions of learning offering post-secondary education.

Ancillary services
Services supplied to the *TS* by *generators*, *distributors* or *end-use customers* necessary for the reliable and secure transport of power from *generators* to *distributors* and *customers* in order to maintain the short-term reliability of the *IPS*. *Ancillary services* shall include but will not be limited to the following*:*

a. Operating reserves

b. *Black start*

c. Reactive power supply

d. *Regulation* and *load following*

Area Control Error
The mismatch between the instantaneous demand and supply of a *control area*. It combines the *frequency* error and the tie line schedule error.

Automatic Generation Control
The Regulation of the power output of electric *generators* within a prescribed area in response to change in *system frequency*, tie-line loading, or the relation of these to each other, so as to maintain the scheduled *system frequency* or the established interchange with other areas within predetermined limits or both

Black start
The provision of generating equipment that, following a total system collapse (black out), is able to:

a. start without an outside electrical supply and
b. energise a defined portion of the *TS* so that it can act as a start-up supply for other capacity to be synchronised as part of a process of re-energising the *TS*.

Budget quotes
A provisional invoice stating connection conditions, inclusive of financial terms.

Busbar
An electrical conduit at a *substation* where lines, transformers and other equipment are connected.

Connection (connected) to the TS
Physical connection of *customer* equipment to the *TS* either directly or through a dedicated transformer provided by the *TNSP*.

Constrained generation
The difference between the energy scheduled under normal operating conditions and the energy scheduled under constrained conditions at a *point of connection*.

Control area
An electrical system with borders defined by points of interconnection and capable of maintaining continuous balance between the generation under its control, the consumption of electricity in the area and the scheduled interchanges with other control areas.

Control centre
An entity responsible for the operational control of the entire or specified electricity network assets.

Customer
Any entity that contracts directly with the *service-provider* for the provision of *transmission* services. These include *generators*, *distributors*, *end-use customers* and *suppliers*.

Day
A period of 24 consecutive hours commencing at 00:00.

Demand side managed load
Load that may be reduced (or increased) in response to a signal from the *System Operator*. It includes *interruptible load*, ripple controlled residential boilers and dual fuel boilers, but excludes *under-frequency customer* load shedding.

Demarcation point
The point at which there is a change over in ownership from *service-provider* to *customer*.

a. *TNSP - Power Stations*

The *HV* bushing stems of the *unit* step-up transformers. The protection circuits of the *units* and step-up transformers shall belong to the *generator*; all other protection circuits and equipment in the *HV* yard shall belong to the *TNSP*.

b. *TNSP – Distributors*, international tie lines and *end-use customers*.

The *demarcation point* shall be at the point where ownership changes hands.

Dependability
The probability of not failing to operate under given conditions for a given time interval [IEC 50 – 448]

Distribution system
An electricity network consisting of assets operated exclusively at a nominal voltage as defined in ZS387 – 1: Power Quality and Reliability Standard.

Distributor
A person/entity that owns or operates/distributes electricity through a distribution system.

Electricity Supply Industry
Electricity industry in Zambia involved in generation, transmission, distribution and supply of electrical energy.

Emergency
A situation where there is unplanned loss of generation, *transmission* or demand facilities that jeopardizes the ability to meet system requirements.

Emergency level generation
Extra capacity from generating *units* over and above their *MCR*ss that can be supplied up to one hour without risk of damage to the plant. This level is achieved without significant additional cost.

Emergency outage
An outage when plant has to be taken out of service immediately so that repairs can immediately be effected to prevent further damage or loss.

End-use customer
Consumers of electricity *connected to the TS.*

Energy Regulation Board
A statutory body established by the Energy Regulation Act Cap. 436 of the Laws of Zambia, to regulate the energy sector in Zambia.

Expert team
A team of experts as established by the *GCTC*

Firm quote
A form of contract negotiated and signed with the *customer* stating final connection conditions, inclusive of financial terms.

Firm supply
A supply that enjoys a level of reliability as specified in the *Network Code*.

Flicker
A cyclic voltage fluctuation, normally between 0.1Hz and 10Hz, that causes optical stress to humans.

Force majeure
Any of the following that prevents any *participant* from executing its obligations as laid down in the *ZGC*:

a. Any overwhelming occurrence of nature that could not reasonably have been foreseen or guarded against;

b. Any of the following occurrences initiated by human agency: war, blockade, foreign hostile acts, civil war, rebellion, revolution, insurrection or sabotage; strikes or other similar stoppages of work by employees that are not caused by unreasonable actions on the part of the *participants*;

c. Any other cause beyond the control of the *participants*, and if all affected *participants* agree by mutual negotiation or otherwise, that such cause should be regarded as *force majeure.*

Forced outage
An outage that is not a *planned outage*.

Frequency
The number of oscillations per second on the *AC* waveform.

Generator
An entity operating a generating unit or *power station*.

Governing
A mode of operation where any change in system *frequency* beyond the allowable *frequency* dead band will have an immediate effect on the unit output according to the *governor droop characteristic*.

Grid Code Secretariat
The entity responsible for the administrative functions as defined in the Governance Code.

Grid Code Technical Committee
A panel of stakeholder representatives charged with strategic review of the *ZGC*.

Grid Service charge
These are the operating costs of the *SO* to ensure safe and reliable operation of the *IPS*. This includes funding of the *Secretariat.*

Gross Asset Value
The GAV represents the total cost of an asset to the *TNSP.* It represents the capital cost, including cost of purchase, freight and insurance, and installation.

Individual *Customer* Charge
These are connection costs that are peculiar to a particular *customer*.

Information
A type of knowledge represented by some data, which can be exchanged, stored or processed electronically or otherwise.

Information owner
The *party* to whose system or installation the *information* pertains

Interconnected Power System
The electrical network that has a measurable influence at *transmission* level, consisting of:

a. *TS*

b. Assets connected to the *TS* and belonging to a *TNSP*

c. *Power stations* with a capacity of more than 100 *KVA* and networks linking such *power stations* to the *TS*.

d. International inter-connectors

e. *Control area* for which the *SO* is responsible

Interruptible load
Consumer load or a combination of consumer loads that can be contractually interrupted or reduced, without notice, on instruction by the *System Operator*.

Islanding
The capability of generating *units* to settle down at nominal speed, supplying own auxiliary load after separation from the grid, at up to full load pre-trip conditions.

Load curtailment
Load reduction by *customers* who are willing and able to reduce there use of power within 1hr on an instructions from *SO*.

Load following
The provision of generation and load response capability, including capacity, energy, and manoeuvrability, that is dispatched by *System Operator* to match power generation and load demand within a scheduling period.

Load reduction
The ability to reduce *customer* demand by *load curtailment* and load shedding.

Losses
The technical or resistive energy losses incurred on the *TS.*

Maximum continuous rating
The capacity that a generating *unit* is rated to produce continuously under normal conditions.

Metering
Equipment used in measuring supply parameters installed at supply points

Metering installation
An installation that comprises an energy meter that is interrogated and has a communication link.

Month
A calendar *month* comprising a period commencing at 00:00 hours on the first *day* of that *month*.

NERC A1 and A2 criteria
The criteria of the NERC that an *ACE* must pass through zero within 10 minutes of its previous zero (A1) and that the average *ACE* in each 10-minute period must be within a specified limit (A2).

Net Asset Value
NAV is defined as the value after deducting all the accumulated depreciation for that asset.

Open access
The availability of *transmission* services to any qualifying *participant* on non-discriminatory terms and conditions

Outage
An interruption of the flow of power to a *point of supply*

Outage Request
An outage request is a written notice from either a *distributor*, *generator*, *end-use customer* or *TNSP* for plant to be taken out of service for planned maintenance, repairs, auditing, *emergency* repairs, construction, refurbishment, inspection, testing or to provide safety clearance for other activities such as servitude clearance, line crossings and underpasses.

Participant

Participants are:

a. *Generators*

b. *end-use customers*

c. *Distributors*

d. *suppliers*

e. *transmission network service-providers*

f. *embedded generators*

g. *System Operator*

h. *Regional Operator*

Party

Any current or future *participant*.

Planned outage
A scheduled outage of equipment that is on a Yearly Maintenance Schedule for any given year.

Point of Common Coupling
The electrical node, normally a busbar, in a *transmission substation* where different feeds to *customers* are connected together for the first time.

Point of connection
The electrical node in a *transmission substation* where a *customer's* assets are physically connected to the *TNSP's* assets.

Point of supply
A *transmission substation* where energy can be supplied to *distributors* and *end-use customers*.

Postage stamp
Pricing method which charges a fixed price per energy unit consumed, independent of distance or voltage level

Power station
One or more *units* at the same physical location

Primary substation equipment
High voltage equipment installed at *substations*

Prudent Utility Practice
Those standards, practices, methods and procedures that conform to safety and legal requirements which are attained by exercising that degree of skill, diligence, and foresight which would be reasonably and ordinarily be expected from skilled and experienced operatives engaged in the same type of undertaking under the same or similar circumstances.

Quote
An invoice stating connection conditions, inclusive of financial terms.

Regional Operator
An entity subordinate to the *SO* and independent from other market *participants* responsible for short-term reliability of the *IPS*, which is in charge of controlling and operating part of the *TS* in real time.

Regulating reserve
Generation capacity or *demand side managed load* available to respond within 10 minutes. This reserve category reserves capacity as part of the *regulation ancillary service*. The purpose of this is to allow for enough capacity to control the *frequency* and *control area* tie-lines power within acceptable limits in real time.

Regulation
The provision of generation and load response capability, including capacity, energy and manoeuvrability, that responds to automatic control signals issued by the *System Operator*.

Rural Electrification Authority
Statutory body established by Act No 20 of parliament to plan and implement the electrification of rural areas in Zambia.

Scheduling
A process to determine which *unit* or equipment will be in operation and at what loading

Secretariat
See *Grid Code secretariat*

Security

The probability of not having an unwanted operation.

Sensitivity Analysis
An exercise to determine the effect of changes in given parameters on an outcome

Service-provider
Any *TNSP* or the *System Operator*.

Stakeholders
Entities having an interest in the *ESI*

Substation
A site at which switching and/or transformation equipment is installed.

System *frequency*
The *frequency* of the fundamental *AC* voltage as measured at selected points by the *System Operator*.

System minutes
A performance indicator for interruptions, defined in the following equation:

$$S_t = \frac{EI_t * 60}{PD_t}$$

where;

- S = *system minutes* interrupted
- EI = energy interrupted (MWh)
- PD = peak demand
- t = period under review

System Operator
An entity responsible for short-term reliability of the *IPS*, which is in charge of controlling and operating the *TS* and dispatching generation (or balancing the supply and demand) in real time.

Transmission
The conveyance of electricity through the *TS*.

Transmission equipment
Any cable, overhead line, transformers, switchgear and equipment for *ancillary services* used for *transmission* purposes

Transmission Network Service-Provider (TNSP)
An entity that is licensed to own and maintain *transmission equipment*.

Transmission System
The *TS* consists of that part of the *IPS* which supplies power in bulk from *power stations* to *distributors* and other *customers* and includes:

a. all *transmission* lines and *substation* equipment on the *IPS* where the nominal voltage is as defined in the ZS387 – 1: Power Quality and Reliability Standard;

b. all associated equipment at TNSP *substations* belonging to the TNSP.

Unit
A device used to produce electrical energy.

Unplanned outage
See *Forced outage*.

Use of system charge
This is a charge applied by a *TNSP* to enable him recover its cost of installation and maintaining its network.

Zambian Grid Code
A code that outlines the responsibilities of participants of the Zambian *ESI*. It consists of the following documents:

a. Acronyms and Definitions (this document)

b. Governance Code

c. Network Code

d. System Operation Code

e. *Metering* Code

f. Transmission Tariff Code

g. *Information* Exchange Code

PART 2 - GOVERNANCE CODE

1 Objective

The objective of this Governance Code is to describe the provisions necessary for the overall administration and review of the various aspects of the *ZGC*.

2 Scope

This Governance Code shall apply to all the various aspects of the *ZGC.* In the event of any conflict with existing PPAs, BSAs and such other similar agreements, the *ZGC* shall take precedence, save where the affected parties have been granted exemptions as provided for under this Code.

3 Responsibility

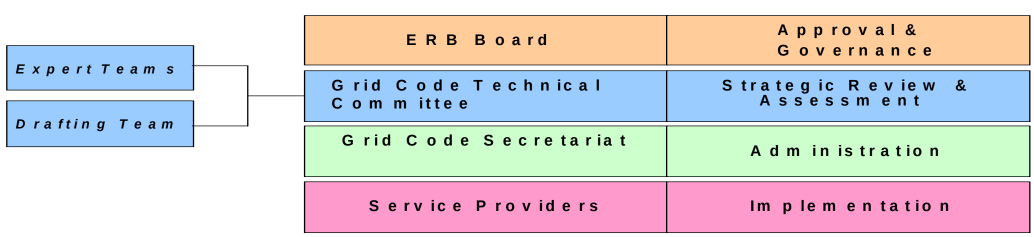
The *Energy Regulation Board (ERB)* has the responsibility to ensure, compliance to the *ZGC* for the benefit of the electricity industry and consumers.

The *Grid Code Secretariat* shall be responsible for implementation, maintenance and revision control, and shall ensure that all recipients of the *ZGC* have the latest revision of the Code, which they shall acknowledge, receipt for.

The *Grid Code Secretariat* shall also ensure that they have in their custody the latest copies of relevant Standards that have been quoted in the *ZGC*.

4 Governance Structure

Figure 1: Grid Code: Assigned Accountabilities



The roles of the various entities in the governance of the *ZGC* are as shown in Figure 1.

4.1 *Energy Regulation Board (ERB)*

The *ERB*, established by the Energy Regulation Act of 1995, shall ensure the implementation of the *ZGC*.

4.2 *Grid Code Technical Committee*

There shall be *a Grid Code Technical Committee* constituted every two years by the *ERB*.

4.2.1 Functions of the *GCTC*

The *GCTC* shall have the following functions:

a. To review and make recommendations regarding proposals to amend the *ZGC*;

b. To make recommendations regarding exemptions to specific provisions of the *ZGC*;

c. To appoint technical experts on specific matters related to the *ZGC*;

d. Attend to the resolution of Non Conformance Report incidences.

4.2.2 Composition of *GCTC*

The *GCTC* shall be composed of representatives of all *stakeholders* of the *Electricity Supply industry (ESI)* in Zambia as follows:

a. One member representing the *System Operator*

b. One member representing the *Regional Operator/s*.

c. Two members representing *Transmission Network Service Providers*.

d. Two members representing *Generators*.

e. One member representing *Distributors*.

f. One member representing the Electrical Engineering *Academia*

g. One member representing the *Engineering Institution of Zambia* council.

h. One member representing the *MEWD*

i. Two members representing *End-use customers*.

j. One member representing *Rural Electrification Authority* (REA).

The *ERB* shall make available publicly the latest list of *GCTC* members within 14 *days* of any change.

4.3 Operations of the *GCTC*

4.3.1 Schedule of Meetings

The *GCTC* shall meet at least once every three *months*. The calendar of meetings shall be set at the first meeting, and the *Secretariat* shall be responsible for sending notices of such meetings.

4.3.2 Chair

The *GCTC* shall elect a Chairperson and a vice Chairperson from amongst the members at the beginning of every year. This position shall be elective on an annual basis. In the event that both the Chairperson and the vice chairperson are unable to attend a meeting, the members present at the meeting shall elect, from among the members, an alternative chairperson for the duration of that meeting.

ERB, *SO* and *MEWD* shall not qualify to the position of Chairperson.

4.3.3 Procedures and Code of Conduct

The *GCTC* shall determine its own meeting procedures and code of conduct.

4.3.4 Alternate Representation

All members of the *GCTC* will nominate alternative representatives from among their representative groups, to attend meetings at which they are unable to be present. A register of alternate members shall be maintained by the *secretariat*.

Alternate members will have voting rights.

4.3.5 Quorum

A quorum shall consist of seven (7) members of the *GCTC*. Decisions by the *GCTC* shall be taken by means of a majority vote of the duly constituted *GCTC*.

4.3.6 Record Keeping

Proceedings of the *GCTC* meetings shall be recorded during all meetings, and shall be kept by the *Secretariat*. The SO shall appoint the secretary for the GCTC meetings.

4.3.7 Funding

The *Secretariat* shall fund the administrative activities of the *GCTC*, on a cost-recovery basis. At the beginning of every year, the *GCTC* shall prepare an operating budget proposal for the following year and submit to the *secretariat* for implementation. The *secretariat* shall fund the operations of the GCTC and its associated committees up to the *ERB* approved budget and recover the costs from *Grid Service Charges*.

4.4 The *Grid Code Secretariat*

The *System Operator* shall serve as the *Grid Code Secretariat*.

The *Secretariat* shall perform the following functions:

a. Co-ordinate the activities of the *GCTC*.

b. Keep a register of licensed undertakings

c. Submit amendments and exemptions to the *ERB* following review by the *GCTC*.

d. Manage the *ZGC* documentation and disseminate *information* to *participants*.

5 Registration of *Grid Code participants*

5.1 Registration and De-registration

The *Secretariat* shall be responsible for making entries in the register of *participants* upon receipt of notification from the *ERB* of licensed entities. *Participants* shall be registered in different categories: *Generator, Embedded generator, Distributor*, *End-use customer* and *Transmission Network Service Providers.*

No entity shall have access to the *TS* before obtaining a license from the *ERB*.

Service-providers shall ensure that *distributors* and *end-use customers* are registered as code *participants* before entering into a contract for services with such *customers*.

A *participant* whose license has been withdrawn by the *ERB* ceases to be a *Grid Code participant.*

5.2 Licensee obligation

Licensees shall be required to comply with the provisions of the *ZGC*.

6 *ZGC* amendment procedure

Any *participant*, member of the *GCTC* or the *ERB* may request amendments to the *ZGC* in the prescribed form

Any *participant* or member of the *GCTC* offering suggestion(s) for amendment on the existing ZGC shall record the proposed change(s) on the prescribed form.

All approved amendments shall be logged on the *ZGC* Request Log as shown in Appendix 3.
The *Secretariat* shall forward the draft proposal to the *GCTC* for the review process.

The *GCTC* shall review the draft proposal for assessment, clarification and reformulation.

If the submission requires expert opinion, the *GCTC* shall determine the necessity for constituting a team of experts. The *GCTC* shall constitute a team of experts for the purpose of allowing expert opinion to be obtained regarding a particular submission, which shall report back to the *GCTC* within a specific period.

The applicant shall attend the *GCTC* sessions and may attend the *expert team* sessions and shall be allowed to make presentations if necessary.

Once the *GCTC* has reviewed submissions, it shall make a formal submission to the *ERB* through the *Secretariat* on all proposed amendments to the *ZGC*. The *GCTC* shall give the decision it reached on each proposal and also provide the *ERB* Board with divergent views on such proposals.

The *GCTC* may convene a Drafting Team if the documentation of the draft amendment so demands.

The *ERB* shall inform the *Secretariat* of the decisions reached and its decision shall be final. The *Secretariat* is responsible for communication of these decisions to all *participants*.

The *Secretariat* shall update the *ZGC* with the approved amendments.

The procedure for amendment could be summarised as shown in Figure 2 below.

7 *ZGC* exemption procedure

Applications for exemption from complying with any provision of the *ZGC* may be made on a prescribed form for any of the following reasons:

a. To provide for existing equipment that has not been designed with consideration of the provisions of the *ZGC*.

b. To facilitate transition through interim arrangements.

c. To facilitate temporary conditions necessitating exemption.

d. Contractual obligations entered into prior to effectiveness of the *ZGC* e.g. Power Purchase Agreements.

All approved exempts shall be logged on the *ZGC* Request Log as shown in Appendix 3.

If a request requires expert opinion, the *GCTC* shall determine the necessity for constituting a team of experts. The *GCTC* shall constitute a team of experts for the purpose of allowing expert opinion to be obtained regarding a particular submission, which shall report back to the *GCTC* within a specific period.

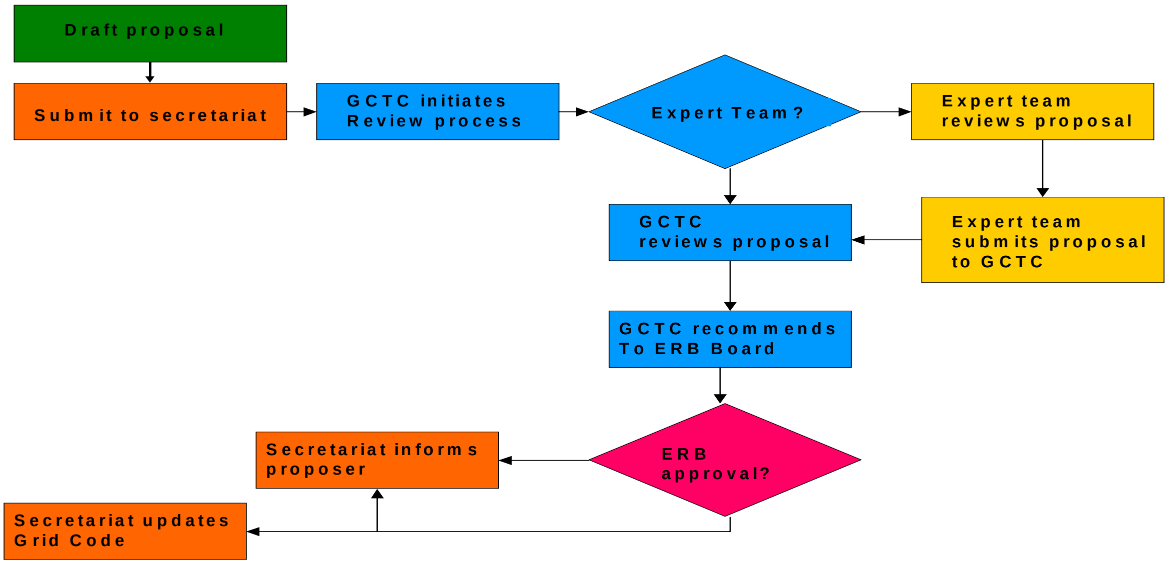
An applicant may attend the *GCTC* sessions as well as the *expert team* sessions and may be allowed to make presentations if necessary.

Once the *GCTC* has reviewed submissions, it shall make a formal submission to the *ERB* through the *Secretariat* on all proposed exemptions to the *ZGC*. The *GCTC* shall give the decision it reached on each request and also provide the *ERB* Board with divergent views on such requests.
The *ERB* shall inform the *Secretariat* of the decisions reached and its decision shall be final. The *Secretariat* is responsible for communication of these decisions to all *participants*.

Full or partial exemption from complying with certain provisions of the *ZGC* may be granted to the *participant* that has applied for that exemption.

The procedure for exemption could be summarised as shown in Figure 2.

Figure 2: Grid Code Amendment/Exemption Approval Process



Appendix 4 shall contain a list of exemptions that have been approved, with the relevant expiry date. The reference number refers to the applicable paragraph in the *ZGC*.

8 Complaint Reporting, Dispute resolution and appeal mechanism

The procedure for handling disputes arising from the implementation of the *ZGC* shall be as follows.

8.1 Complaint Reporting

8.1.1 Complaints about the operations of the *Secretariat* or *GCTC*

Any complaint regarding the operations of the *Secretariat* or the *GCTC* shall firstly be addressed in writing to the *Secretariat*. The *GCTC* shall attend to such complaints at or before the next scheduled meeting. If the complaint is not resolved, the matter shall be referred to the *ERB* as a dispute and shall follow the procedure described in Section 8.2.

8.1.2 Complaints between *customers* and *service providers*

Complaints arising between *Customers* and *Service Providers* shall be handled in accordance with section 8.1.3 and section 8.1.4.

8.1.3 Incident report (IR)

An incident report is a formal communication of an occurrence that results in disagreements.

A *customer* may issue an incident report to a *service-provider* on becoming aware of an occurrence. The *service-provider* shall provide a reason for the incident, what has been done to address it, and, if appropriate, indicate what action it shall take to avoid such an incident(s) in the future.

A *service-provider* may also issue an incident report to a *customer*, where the *customer* does not comply with necessary requirements. The *customer* shall provide the *service-provider* with reasons for the incident and, where appropriate, indicate the measures that will be taken to address the problem.

Service-providers shall keep a log of all incident reports received and a log of all incident reports sent to *customers*.

Incident reports are operational in nature and generally require action only by technical and *customer*-relations staff.

8.1.4 Non-conformance report

NCRs are generated to indicate problems that require *GCTC* intervention.

A *customer* under any of the following conditions may issue an NCR after an Incident Report (IR):

a. the *service-provider* fails to provide the appropriate feedback to the IR;

b. the *service-provider* willfully misrepresents the facts concerning the incident;

c. the *service-provider* fails to implement the agreed preventative actions within the agreed timeframe;

d. the number of incident reports becomes excessive in relation to historical performance;

e. the actions arising from an *ERB* mediation / arbitration process are not adhered to.

A *service provider* under any of the following conditions may issue an NCR after an Incident Report (IR)

i. the *customer* fails to provide the appropriate feedback;

ii. the *customer* willfully misrepresents the facts concerning an incident;

iii. the *customer* fails to implement the agreed preventative actions within the agreed timeframe;

iv. the number of incident reports becomes excessive in relation to historical performance;

v. the actions arising from an *ERB* mediation/arbitration process are not adhered to.

In the case where the *parties* agree and assign responsibilities outlined in the NCR, both participants, within an agreed time frame, shall implement remedial action.

Service-providers shall report annually to the *ERB* on the following aspects of the procedure:

(a) The number of NCRs for each *customer* category

(b) The number of closed-out NCRs for each *customer* category

Upon a report or suspicion of non-compliance the *ERB* may seek to:

(i) resolve the issue through negotiation;

(ii) take action in terms of the procedures for handling licensing contraventions;

(iii) advise the *parties* to consider an application for amendment;

(iv) advise the *parties* to consider an application for exemption.

8.2 Disputes

Disputes are unresolved complaints between *parties* that require intervention. A dispute may be declared when an NCR cannot be closed out in the agreed timeframe. At this stage the complaint shall be referred to the *ERB*.

8.2.1 Submission of a Dispute to *ERB*

Any *party* may submit a dispute to the *ERB* provided the required process of section 8.1 has been followed.

When a dispute is raised with the *ERB*, *participants* shall provide the following *information*:

a. The full history of relevant incident reports
b. The detailed *NCR* and accompanying *information* that gave rise to the dispute
c. A written report from each *participant* detailing the reason for not being able to close out the *NCR*

Disputes received by the *ERB* shall be recorded in accordance with Appendix 5. The following shall be considered by the *ERB* in dealing with the dispute:

i. The effectiveness of the incident resolution management system (how the problem was addressed at each stage before a dispute was declared)
ii. How thoroughly the problem has been studied by both *participants*
iii. What action has already been taken
iv. The actual cost impact/environmental impact/other impact on the *parties*
v. Whether the complaint is reasonable
vi. Whether a timeframe cannot be agreed for closing out an *NCR*

The *ERB* may choose initially to act as a mediator, but shall ultimately act as an arbitrator. When considering a ruling in its role as arbitrator, the *ERB* may choose to consult any recognized person/body.

The *ERB* shall continue to develop a database of precedents based on disputes it has resolved. These precedents shall be used in rulings on a complaint/dispute. However, Precedents set by any other *parties* in attempting to resolve an *NCR* shall not necessarily be upheld by the *ERB*.

The *ERB* shall consider the following, amongst other things, during the arbitration process:

i) Existing and historical performance trends

ii) Reference standards

iii) The appropriate network design / operation standards

iv) A developing database of precedents with similar events

v) Historical agreements between the *participants*

vi) The total cost impact

Where the outcome of any dispute resolution proceedings would require or imply an amendment to the *ZGC*, the *ERB* shall first consult with the *GCTC*.

Any *party* objecting to decisions or recommendations made by the *GCTC* or the *ERB* over a particular dispute shall submit the objection in writing to the *ERB*.

9 Grid Code Compliance audits

Any *participant* may request the *GCTC* to conduct an audit of another *participant* relating to compliance with part of or the entire *ZGC*. The requesting *participant* may not request such *information* in relation to a particular section of the *ZGC* within six *months* of a previous request made under this clause in relation to the relevant section.

A request under this clause shall include the following *information*:

a. The nature of the request;

b. The name of the representative appointed by the requesting *participant* to conduct the investigation; and

c. The date and time or times at which the *information* is required.

A *participant* may not unreasonably withhold any relevant *information* requested. It shall be provided to the *GCTC* with such access to all relevant documentation, *data* and records (including computer records or systems) as is reasonably requested.

The cost of such audits will be borne by the complainant if the audit reveals compliance and by the *participant* being audited if the audit reveals non-compliance.

Appendix 1: GRID CODE AMENDMENT REQUEST FORM

GC A No:……………………………

Text to be amended: Section(s)……………………. Page(s)………………...
Change from (if additional space is required, please use attachments)
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Change to (if additional space is required, please use attachments)
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Reason for change(s)
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Change Initiated by……………………. Date ……………………………………

Checked by:
(*Secretariat*) ……………………………………. Date ……………………………..

Approved/Not approved:
(*GCTC* CHAIRPERSON) ………………………Date …………………………..

Appendix 2: GRID CODE EXEMPTION REQUEST FORM

GC E No:……………………………

Text to be exempted from: Section(s)…………………. Page(s)………………...

Reason for exemption (if additional space is required, please use attachments)
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Additional *Information* (if additional space is required, please use attachments)
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…………………………………………………………………………Duration:
From:……………………………To:……………………………………..

Exemption Applicant's Name:……………………. Date …………………………

Checked by:
(*Secretariat*) ……………………. Date ……………………………..

Recommended by:
(*GCTC* Chairperson) ……………………. Date ……………………………..

Approved/Not approved:
(*ERB* BOARD CHAIRPERSON)……………………Date ………………………..

APPENDIX 3: *ZGC* AMENDMENT/EXEMPTION REQUEST LOG

GC A/E No.	APPLICANT	DATE SUBMITTED	DATE APPROVED/NOT APPROVED	EFFECTIVE DATE

APPENDIX 4: LIST OF APPROVED EXEMPTIONS

CODE:			
REFERENCE NO.	REASON FOR EXEMPTION	REQUESTED BY	EXPIRY DATE

APPENDIX 5: LOG OF DISPUTES BETWEEN *PARTICIPANTS*

DISPUTE No.	COMPLAINANT	DEFENDANT	COMPLAINT		RESOLUTION	
			DESCRIPTION	DATE	DESCRIPTION	DATE

PART 3 - NETWORK CODE

1 Objective

This code specifies the minimum technical design and operational criteria for connection to the *TS*.

2 Scope

The Network Code shall apply to all *participants.*

3 Applications for *transmission* connections

All *customers* seeking connection or modification to the existing *TS* shall apply in writing to the *TNSP*.

The *TNSP* shall provide quotes for new connections or for upgrading existing connections, according to the approved tariff methodology as per Tariff Code and within the following time frames:

	Budget Quote	**Firm Quote**
Connection service (*days*)	≤30	≤60
Use of network service (*days*)	≤15	≤30

The *customers* may request provisional quote *information* from the *TNSP* that shall be provided without commitment and without detailed studies.

The agreed time period for connecting *end-use-customers* or upgrading connections shall be negotiated between the *TNSP* and the *end-use-customers* in every instance.

The *TNSP* shall use the standard application form as shown in Appendix 3 for the processing of applications which should be read in conjunction with *information* provision requirements as specified in the *Information Exchange Code*.

End-use-customers shall enter into a connection contract and a *Supply Agreement* with the *TNSP* in advance of construction of the connection facilities.

End-use-customers shall enter into a *use-of-system contract* with the *TNSP* before the commencement of energy transactions over the *TS*.

4 Connection conditions

This section specifies the minimum technical and design requirements that *participants* connected to or seeking connection to the *TS* shall adhere to.

4.1 *Generator* connection conditions

This section defines minimum requirements for *generators* connected to the *TS,* which are required to comply with the *Grid code*.

Generators with capacity ratings as specified in Tables 4.1 (a) and 4.1 (b) below shall be subject to *GCRs*.
The *SO* shall evaluate and specify the need for optional *IPS* requirements which may not have been indicated in Tables 4.1 (a) and (b). The *SO* shall, on request, make available the requirements pertaining to the decision.

Table 4.1(a) Summary of the requirements applicable to specific ratings of non-Hydro *Units*

Grid Code **Requirement**		***Unit*s other than Hydro (MVA rating)**		
		<20	**20 to 100**	**101 to 500**
***GCR*1**	**Grid Protection**			
	Backup Impedance	No	No	
	Loss of Field	Yes	Yes	
	Generator transformer backup earth fault	Yes	Yes	
	HV Breaker Fail	Yes	Yes	
	HV Breaker Pole Discrepancy	Yes	Yes	
	Unit Switch-on-to-standstill Grid Protection (achieved with controls)		Yes	
	Main Grid Protection only			
	Main Grid Protection (with self-monitoring system) or main and backup			
	Main and Backup Protection (with self monitoring or monitoring systems)	Yes	Yes	
	Reverse Power	Yes	Yes	
*GCR*2	Excitation system requirements	Yes	Yes	
	Power System Stabilizer (To comment later)	-	-	
	Limiters (pressure, temp, speed available)	Yes	Yes	
*GCR*3	Reactive Capabilities		Yes	
*GCR*4	*Governing*	Yes	Yes	
*GCR*5	Black Starting	Yes	Yes	
*GRC*6	*Emergency unit* capabilities	Yes	Yes	
*GCR*7	Independent action for control in system island	Yes	Yes	

Table 4.1(b) Summary of the requirements applicable to specific classes of Hydro *units*

***Grid Code* Requirement**		Hydro *Units* (MVA rating)		
		<20	20 to 100	101 to 500
*GCR*1	**Protection**			
	Backup Impedance	Yes	Yes	Yes
	Loss of Excitation	Depends on System Requirements	Yes	Yes
	Gen transformer HV (backup) earth fault	Yes	Yes	Yes
	Gen Tx HV REF protection	Yes	Yes	Yes
	HV Breaker Fail	-	Yes	Yes
	Breaker Pole Discrepancy	Yes	Yes	Yes
	Unit Switch-onto-standstill Protection		Depends on System Configuration	Depends on System Configuration
	Main Protection	Yes	Yes	Depends on System Configuration
	Reverse Power	Depends on System Configuration	Yes	Yes
*GCR*2	Excitation system requirements	Yes	Yes	Yes
*GCR*3	Reactive Capabilities	Depends on System Configuration	Yes	Yes
*GCR*4	*Governing*	Depends on System Requirements	Yes	Yes
*GCR*5	Black Starting	-	Yes	Yes
*GCR*6	*Emergency unit* capabilities	Depends on System Requirements	Depends on System Requirements	Yes
*GCR*7	Independent action for control in system island	-	-	Depends on System Requirements

The *TNSP* shall offer to connect and, subject to the signing of the necessary agreements, make available a *point of connection* to any requesting *generator* licensed to generate electricity.

4.1.1 Protection (GCR 1)

A generating *unit*, *unit* step-up transformer, *unit* auxiliary transformer, associated busbar ducts and switchgear shall be equipped with protection functions, maintained in line with international best practices, to rapidly disconnect appropriate plant sections should a fault occur within the relevant Protection zones which fault may reflect into the *TS*.

Protection supplies for Main protection and other protection types shall be separately fused.

The *IPS* shall be protected with the following functions:

a. Main protection

This protection shall be installed in the *HV* yard *substation* or in the *unit* protection panels. If this protection is installed in the *unit* protection panels then the *DC* supply for this protection and that used for control circuits shall be at least separately fused.

b. Backup Impedance

An impedance facility with a large reach shall be used. This shall operate for phase faults in the *unit*, in the *HV* yard or in the adjacent *transmission* lines, with a suitable delay, for cases when the corresponding main protection fails to operate. The impedance facility shall have fuse fail interlocking.

c. Loss of Field

All generating *units* shall be fitted with loss of field facility that matches the system requirements. The type of facility to be implemented shall be agreed with the *TNSP*.

d. Generator Transformer HV back-up E/F Protection

This is shall be an *IDMT* facility that shall monitor the current in the *unit* transformer neutral.

e. HV Breaker Fail Protection

The “breaker fail” protection shall monitor the *HV* circuit breaker's operation for protection trip signals, i.e. fault conditions.

f. *HV* Pole discrepancy protection

The pole discrepancy protection shall cover the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal.

g. *Unit* Switch onto Standstill protection

This protection shall be installed in the *HV* yard *substation* or in the *unit* protection panels. If this protection is installed in the *unit* protection panels then the *DC* supply for this protection and that used for the circuit-breaker closing circuit shall be the same.

In addition, should system conditions dictate, other protection requirements shall be determined by the *SO* in consultation with the *generator* and these should be provided and maintained by the relevant *generator* at its own cost.

Required *HV* breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the *TS*.

All protection interfaces with the *TNSP* shall be co-ordinated between the *participants*.

The settings of all the protection tripping functions on the *unit* protection system of a *unit*, relevant to *IPS* performance and as agreed with each *generator* in writing, shall be co-ordinated with the *transmission* protection settings. These settings shall be agreed between the *TNSP* and each *generator*, and shall be documented and maintained by the *generator*, with the reference copy, which reflects the actual plant status at all time, held by the *TNSP*.

Protection setting documents shall illustrate plant capabilities and the relevant protection operations.

Prototype and routine testing shall be carried out as defined Appendix 2, section A.5.1

Any work on the protection circuits interfacing with *transmission* protection systems (e.g. bus zone) shall be sanctioned by the *SO*.

h. Reverse Power

This protection shall be installed in the *HV* yard *substation* or in the *unit* protection panels. If this protection is installed in the *unit* protection panels then the *DC* supply for this protection and that used for the circuit-breaker closing circuit shall be the same.

4.1.2 Excitation system requirements (GCR2)

A continuously acting automatic excitation control system (*AVR*) shall be installed to provide constant terminal voltage control of the *unit*, without instability, over the entire operating range of the *unit*. (Note that this does not include the possible influence of a power system stabilizer.) Excitation systems shall comply with the requirements specified in IEC 60034.

The excitation control system shall be equipped with an under-excitation limiter, load angle limiter and flux limiter as described in IEC60034-16-1.

The excitation system shall have a minimum excitation ceiling limit of 1.6 pu rotor current, where 1 pu is the rotor current required to operate the *unit* at rated load and at rated power factor.

The settings of the excitation system shall be agreed between the *SO* and each *generator*, and shall be documented, with the master copy held by the *SO*. The *generators* shall control all other copies. The procedure for this is shown Appendix 2, Section A.5.2.

In addition, the *unit* shall be capable of operating in the full range as indicated in the capability chart supplied as part of Appendix 3 of the *Information* Exchange Code. Test procedures are shown in Appendix 2, Section A.5.5.

Power system stabilizers as described in IEC60034-16-1 are a requirement for all new *units*, and for existing *units* retrofitting may be required depending on *IPS* requirements. The requirements for other excitation control facilities and *AVR* refurbishment shall be determined in conjunction with the *SO*.

Routine and prototype response tests shall be carried out on excitation systems as indicated in Appendix 2, Section A.5.2 and in accordance with IEC60034-16-3.

4.1.3 Reactive capabilities (GCR3)

All new *units* shall be capable of supplying rated power output (*MW*) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the *unit* terminals.

Reactive output shall be fully variable between these limits under *AVR*, manual or other control.

Routine and prototype response tests shall be carried out to demonstrate reactive capabilities as indicated in Appendix 2, Section A.5.3.

4.1.4 *Governing* (GCR4)

4.1.4.1 Design Requirements

The *SAPP* Operating Sub-committee approved relaxed *frequency* bands in the power pool from 0.05Hz to +0.15Hz during normal operations[1]. All *units* above 50 *MVA* shall have an operational governor that shall be capable of responding according to the minimum requirements set out in this document.

4.1.4.2 System *Frequency* Variations

The nominal *frequency* of the *TS* is 50*Hz* and is normally controlled within the limits of ±0.15Hz unless exceptional circumstances prevail. The system *frequency* could rise or fall in exceptional circumstances and generating *units* must be capable of continuous normal operation for the high and low *frequency* conditions set out in section 4.1.5 when the *TS* comes out of synchronism with the *SAPP* network.

Design of turbo-alternator *units* must enable continuous operation, at up to 100% active power output, within this range.

Hydro-alternator *units* must be capable of continuous normal operation for high *frequency* conditions described in section 4.1.5.4 and low *frequency* conditions as described in 4.1.5.6.

4.1.4.3 High *Frequency* Requirements for Turbo-alternators

All synchronized *units* shall respond by reducing active power to *frequencies* above 50 *Hz* plus allowable limits described in section 4.1.5.2. Speed governors shall be set to a predetermined droop characteristic. The response shall be fully achieved within the time set in the dynamic study of the system and must be sustained for the duration of the *frequency* excursion. The *unit* shall respond to the full designed minimum operational capability of the *unit* at the time of the occurrence.

Over-*frequency* Conditions above 50.15Hz

The *frequency* requirements and behaviour of turbo generators will be set out in the dynamics study, which will be commissioned by the *GCTC*.

[1] *SAPP* Operating Guidelines

Turbo generators will be equipped with over *frequency* protection at a set value, but this value shall not be set at a level likely to compromise the system *security* and safety.

4.1.4.4 High *Frequency* Requirements for Hydro Alternators

All synchronised hydro *units* shall respond by reducing active power to *frequencies* above 50 *Hz* plus allowable limits described in section 4.1.5.7. Speed governors shall be set to give a predetermined droop characteristic. The response shall be fully achieved within the stipulated time and must be sustained for the duration of the *frequency* excursion. The *unit* shall respond to the full load capability range of the *unit*.

Hydro generators will be equipped with over *frequency* protection at a set value, but this value shall not be set at a level likely to compromise the system *security* and safety.

4.1.4.5 Low *Frequency* Requirements for Turbo-alternator *Units*

Low *frequency* response is defined as an *ancillary service* in the form of *operating reserve*. However all *units* shall be designed to be capable of having a droop characteristic with a preset minimum response within a certain time of a *frequency* incident within which it must be sustained.

Under *frequency* protection shall be equipped at preset levels, which shall be coordinated with automatic load shedding.

Low *frequency* below 49.85Hz

The behaviour of generating *units* will be determined by a dynamics study to be commissioned by the *GCTC*.

4.1.4.6 Low *Frequency* Requirements for Hydro-alternator *Units*

All reasonable efforts shall be made by the *generator* to avoid tripping of the hydro-alternator for under *frequency* conditions provided that the system *frequency* is above 47.5Hz. At this frequency, the *IPS* has been set to separate with all the interconnectors at a preset time delay. This value is meant to preserve system integrity.

If the system *frequency* falls below 47.5Hz for more than 1 second, independent action may be taken by a *generator* to protect the *unit*. Such action includes ability to *islanding* and independent action in island position.

4.1.4.7 Dead band

The maximum allowable dead band shall be ±0.15 Hz for *governing*. That is, no response is required from the *unit* while the *frequency* is greater than 49.85 and less than 50.15 Hz.

Routine and prototype response tests shall be carried out on the *governing* systems as indicated in Appendix 2, Section A.5.4

4.1.5 Black starting (GCR5)

Power stations that have declared that they have a station *black start* capability shall demonstrate this facility by test as described in Appendix 2, Section A.5.5.

Black start capable *power stations* may be called from time to time to carry out a *black start* as described in Appendix 2, Section A.5.5.

4.1.6 *Emergency unit* capabilities (*GCR*6)

All *generators* shall specify their *units'* capabilities for providing *emergency* support under abnormal *power system* conditions, as detailed in the System Operation Code.

4.1.7 Facility for independent *generator* action. (*GCR*7)

Frequency control under system island conditions shall revert to the *power stations* as the last resort, and *units* and associated plant shall be equipped to handle such situations. The required control range is from 49.85Hz to 50.15Hz.

4.1.8 Testing and compliance monitoring

A *generator* shall keep records relating to the compliance by each of its *units* with each section of this code applicable to that *unit*, setting out such *information* that the *SO* reasonably requires for assessing power system performance (including actual *unit* performance during abnormal conditions).
A *generator* shall review, and confirm to the *SO*, compliance by each of that *generator's units* with every *GCR* as specified in Appendix 2.
A *generator* shall conduct tests or studies to demonstrate that each *power station* and each generating *unit* complies with each of the requirements of this code. Tests shall be carried out on new *units*, after every *outage* where the integrity of any *GCR* may have been compromised, to demonstrate the compliance of the *unit* with the

relevant *GCR*(s). The *generator* shall continuously monitor its compliance in all material respects with all the connection conditions of the *ZGC*.

Each *generator* shall submit to the *SO* a detailed test procedure, emphasizing system impact, for each relevant part of this code prior to every test.

If a *generator* determines, from tests or otherwise, that one of its *units* or *power stations* is not complying with any material respect of one or more sections of this code, then the *generator* shall:

a. promptly notify the *SO* of that fact;

b. promptly advise the *SO* of the remedial steps it proposes to take to ensure that the relevant *unit* or *power station* (as applicable) can comply with this code and the proposed timetable for implementing those steps;

c. diligently take such remedial action as will ensure that the relevant *unit* or *power station* (as applicable) can comply with this code. The *generator* shall regularly report in writing to the *SO* on its progress in implementing the remedial action;

d. and after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *SO* that the relevant *unit* or *power station* (as applicable) is then complying with this code.

4.1.9 Non-compliance suspected by the *SO*

If at any time the *SO* believes that a *unit* or *power station* is not complying with this code, then:

a. The *SO* may notify the relevant *generator* of such non-compliance specifying the code section concerned and the basis for the *SO's* belief.

b. The *SO* may issue an instruction requiring a *generator* to carry out a test to demonstrate that the relevant *power station* complies with the GCRs. A *generator* may not refuse such an instruction provided it is issued timeously and there are reasonable grounds for suspecting non-compliance

However, if the relevant *generator* believes that the *unit* or *power station* (as applicable) is complying with the code, then the *SO* and the *generator* must promptly meet to resolve their difference.

4.1.10 *Unit* modifications

a. Modification proposals

If a *generator* proposes to change or modify any of its *units* in a manner that could reasonably be expected to either adversely affect that *unit's* ability to comply with this code, or changes the performance, *information* supplied, settings, etc, then that *generator* shall submit a proposal notice to the *SO* which shall:

i. contain detailed plans of the proposed change or modification;

ii. state when the *generator* intends to make the proposed change or modification; and

iii. set out the proposed tests to confirm that the relevant *unit* as changed or modified operates in the manner contemplated in the proposal, can comply with this code.

If the *SO* and the generator disagree on the proposal submitted, the two shall refer the matter to the *ERB* for resolution.

b. Implementing and Testing modifications

The *generator* shall ensure that an approved change or modification to a *unit* or to a subsystem of a *unit* is implemented in accordance with the relevant proposal approved by the *SO*.

The *generator* shall notify the *SO* promptly after an approved change or modifications to a unit has been implemented, and confirm that it conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions.

4.1.11 Equipment requirements

Where the *generator* needs to install equipment that connects directly with *TNSP* equipment, for example in the *HV* yard of the *TNSP*, such equipment shall adhere to the *TNSP* design requirements as set out in this code.

The *TNSP* may require *end-use customers* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

4.2 *Distributors* and *end-use customers*

This section describes connection conditions for *distributors* and *end-use customers*. The *TNSP* shall offer to connect and, subsequent to the signing of the relevant agreements as stated in Section 3, make available a *point of connection* to any requesting *distributor* or *end-use customer*.

4.2.1 Power factor

Distributors and *end-use customers* shall take all reasonable steps to ensure that the power factors at the *point of supply* is at all times 0.92 lagging or better, unless otherwise agreed to in existing contracts between the *participants*. This requirement also applies to each *point of supply* individually for *end-use customers* with more than one *point of supply*. A leading power factor shall not be acceptable, unless specifically agreed to in writing.

A penalty and incentive scheme shall be agreed between the *TNSP* and the *Distributor* and end-use *customer*. Should the power factor be out of the agreed limits the penalty/incentive scheme will come into play. The *participants* shall co-operate in determining the plans of action to rectify the situation on a permanent basis. Overall lowest cost solutions shall be sought.

4.2.2 Protection

Each *participant* shall take all reasonable steps to protect its own plant as per *prudent utility practice*.

The *SO* protection requirements, with which the *end-use customers* shall interface, are described in Section 6. The relevant *participants*, in-so-far as the equipment of one *participant* may have an impact on the other, shall agree to the detailed protection applications, in writing. *End-use customers* connected directly to the *transmission substations* shall ensure that they comply with the protection standards of the relevant *TNSP*.

The *participants* shall co-ordinate protection to ensure proper grading and protection coordination.

Protection *dependability* (IEC50-448) shall not be less than 99%.

4.2.3 Fault levels

The *End-use customer* shall ensure that his equipment is capable of operating at specified fault levels as published by the *SO* from time to time.

In the event that works are carried out that will result into fault level ratings exceeding that of *end-use customer* equipment, the *TNSP* shall seek overall lowest cost solutions to address the problem. Corrective action shall be for the cost of the relevant asset owner that has caused the increase in fault levels.

4.2.4 Network Performance

If the *distributor* or *end-use customer* network performance falls below the specifications of ZS387 Electricity Supply – Power Quality and Reliability standard, or affects the QOS to other *end-use customers,* or causes damage (direct or indirect) to the *TNSP* equipment, the process for dispute resolution, as described in the Governance Code, shall be followed.

If *distributors* or *end-use customers* are aware that their network performance could be unacceptable as described above, they shall take reasonable steps at their own cost to overcome the shortcomings. These changes should be effected in consultation with the *TNSP* on both the technical scope and the time frame.

4.2.5 Equipment requirements

Where the *distributor* or *end-use customer* needs to install equipment that connects directly with *TNSP* equipment in *transmission substations*, such equipment shall adhere to the *TNSP* design requirements as set out in Section 5.

The *TNSP* may require *end-use customers* to provide documentary proof that their connection equipment complies with all relevant design requirements, both by design and by testing.

4.2.6 Additional Reinforcement

An *end-use customer* may request additional reinforcements to the *TS* over and above that which could be economically justified as described in the section on *TS* Planning and Development. The relevant *TNSP* shall provide such reinforcements if the *end-use customer* agrees to bear the costs, which shall be priced according to the *Transmission* Tariff Code provisions or negotiated contract.

5 *TNSP* technical design requirements

The purpose of this section is to document the design and other technical standards that the *TNSP* shall adhere to.

5.1 Equipment design standards

Primary substation equipment shall comply with the relevant *IEC* specifications. The *TNSP* shall ensure that the agreed design standards at the *end-use customer* interface are documented. This documentation shall address the interface for the primary equipment and secondary circuits. Consideration shall also be given to possible common *DC* supplies, *AC* supplies, compressed air systems and fencing.

The *TNSP* shall ensure that switching devices at or near a *power station* are adequately rated and capable of switching loads and fault currents without generating undue switching surges. Switching surge protection provided to the generating *unit* should be as provided by IEC60099.

End-use customers may require the *TNSP* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

5.2 Clearances

Safety clearances from *TS* equipment shall at least comply with ZS418 Electrical Safety Code – Code of Practice.

5.3 *CT* and *VT* ratios and cores

The asset owner in consultation with the other relevant participants shall determine *CT* and *VT* ratios and cores.

A *TNSP* or an *end-use customer* connected to the *TS* shall ensure that measurement equipment complies with the accuracy classes specified in Electricity *metering* – Code of Practice: ZS 647 for the purpose of operation and control of the *IPS*.

5.4 Standard *busbar* arrangements and *security* criteria

The standard *substation* arrangement shall be based on providing one *busbar* zone for every main transformer/line normally supplying that *busbar*. System reliability criteria as described in the *TS* Planning and Development Section should also be adhered to.

5.5 Motorised Isolators

In the interest of safety, all new *substations* with voltage levels of above 132*kV* shall be provided with motorized isolators. *Substations* with voltages equal to or lower than 132*kV* may be fitted with motorized isolators depending on the merits of cost and operations.

5.6 Earthing and Surge Protection

The *TNSP* shall ensure adequacy of all earthing installations to provide for:

a. Safety of personnel and the environment

b. Correct operation of all protection systems

c. Agreed design and performance levels

5.6.1 Earthing isolators

Earthing isolators shall be provided at new *substations* where the fault level is designed for 20 *kA* and above.

The *TNSP* shall provide adequate protection to limit lightening surges at the connection point as specified in IEC 60071 and IEC 60099.

5.7 Tele-control

A *participant* may be permitted to have tele-control equipment in the *substations* / *yards* / buildings of the other *party*, to perform agreed monitoring of own equipment and other mutually agreed equipment. Access shall be provided to such equipment.

5.8 *Substation* drawings

The following minimum set of drawings shall be made available by the respective asset owners for all *points of supply*, if required by the other *party* for the purposes of connection:

a. Station Electric Diagram
b. Key Plan
c. Bay Layout Schedules
d. Foundation, Earth-mat/ Earth-pit and Trench Layout
e. Steelwork Marking Plan
f. Security Fence Layout
g. Terrace, Road and Drainage Layout
h. Transformer Plinth
i. General Arrangement
j. Drawings with Sectional details
k. Slack Span Schedule
l. Barrier Fence Layout
m. Security Lighting
n. Floodlighting Parameter Sketch
o. Protection details
p. Contour Plan

All drawings shall use the standard electrical symbol set defined in Appendix 1.

5.9 Recorders

The *TNSP* shall install *QOS* recorders as stipulated by ZS387 Electricity Supply-Power Quality and Reliability standard at *points of supply* or *points of connection*.

The *TNSP* shall install disturbance recorders at locations in the network that shall enable the *SO* to adequately analyze system disturbances.

Access to the records shall be as specified in the *Information* Exchange Code.

5.10 Fault Levels

The *TNSP* shall maintain contracted minimum fault levels at each *point of supply*.

Where mitigating actions have been put in place to reduce fault levels, the *SO* shall document maximum fault levels, before and after such actions.

The *TNSP* and *SO* shall liaise with *end-use customers* on how fault levels are planned to change and on the best overall solution when equipment ratings become inadequate. The *TNSP* shall communicate the potential impact on the safety of people when equipment ratings are exceeded.

5.11 The *TNSP's* delivered *QOS*

The *TNSP* shall comply with ZS387 Electricity Supply – Power Quality and Reliability standard at every *point of supply*.

Where the *TNSP* fails to meet the standard parameters, it shall take reasonable steps at own cost to overcome the shortcomings. These changes should be effected in consultation with the *end-use customer* on both the technical scope and the time frame.

6 Service Provider Protection requirements

This section specifies the minimum protection requirements for *TNSP*'s as well as typical settings, to ensure adequate performance of the *TS* as experienced by the *end-use customers*.

The *TNSP* shall conduct periodic or CBM testing of equipment and systems to ensure and demonstrate that these are performing to the design specifications.
The *TNSP* shall make available to *end-use customers* results of tests performed on equipment.

6.1 Equipment protection requirements

6.1.1 Feeder protection: above 132*kV*

6.1.1.1 Protection Design Standards

New feeders shall be protected by two main protection systems – Main 1 and Main 2 of which one of them shall be line differential and the other distance protection. The Main 1 and Main 2 protection systems shall be fully segregated in secondary circuits.

An additional Directional Earth Fault function (DEF) shall be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in detection of high resistance faults.

Non-directional over-current and earth-fault protection functions shall be installed either separate or as integral part of the main protection relay to provide optional backup. This could use definite time and Inverse Definite Minimum Time (*IDMT*) over-current.

6.1.1.2 Protection Settings

The protection relays shall provide reliable protection against all possible short circuits; provide remote and/or local back up for *busbar* faults that are not cleared and those that are not set to provide overload tripping. Where specifically required, the feeder protection may be set to provide remote back up for other faults as agreed upon with other *participants*.

6.1.1.3 Automatic Re-closing (*ARC*)

Automatic re-closing (*ARC*) facilities shall be provided on all feeders.

The *SO* shall decide on *ARC* selection based on real time system, environmental constraints and consultation with *end-use customers*, with regard to equipment capabilities and in accordance with the *ARC* philosophy in this section. All *ARC* settings and methodology shall be implemented by the *TNSP* and be made available to *end-use customers* on request.

6.1.1.4 Power Swing Blocking

New distance relays on the *TS* shall be equipped with PSB facility. Unwanted operations of distance relays during power swing conditions shall be blocked on the *TS*. On *Control Area* tie lines, the philosophy implemented under *SAPP* shall prevail.

6.1.2 Feeder protection: 66*kV* and below, at *TNSP substations*

6.1.2.1 Design Standard

These feeders shall be protected by a single protection system, incorporating either distance or differential protection relays, unless otherwise agreed. Definite time and Inverse Definite Minimum Time (IDMT) over-current shall provide back up.

The protection shall be equipped with automatic re-closing. Synchronising relays shall be provided on feeders that operate in “ring supplies” and are equipped with line voltage transformers.

6.1.2.2 Protection Settings

Protection relays shall provide reliable protection against all possible short circuits, provide remote and/or local back up for uncleared *busbar* faults and should not be set to provide time delayed overload tripping where measurements and alarms are provided on the *SCADA* system.

6.1.2.3 Automatic Re-closing

The *end-use customer* shall determine *ARC* requirements. The *SO* may specify additional *ARC* requirements for system *security* reasons, which could extend beyond the *TNSP substations*.

6.1.3 Tele-protection requirements

New distance protection systems shall be equipped with tele-protection facilities to enhance the speed of operation.

6.1.4 Transformer and reactor protection

The standard schemes for transformer protection shall be designed to provide the requisite degree of protection for the following fault conditions:

a. Faults within the tank

b. Faults on transformer connections

c. Overheating

d. Faults external to the transformer

The *TNSP* shall consider the application of the following schemes in the design of the protection system:

i. Transformer *IDMT* Earth Fault (E/F):

ii. Transformer *HV/MV IDMT* Over-current (*O/C*)

iii. Transformer *HV/MV* Instantaneous *O/C*

iv. Transformer *LV* (Tertiary) *IDMT*/Instantaneous *O/C*

v. Transformer Current Differential Protection

vi. Transformer High Impedance Restricted *E/F*

vii. Transformer Thermal Overload

6.1.5 *Transmission busbar* protection

Bus-bars shall be protected by bus-zone current differential protection set to be as sensitive as possible for the “in-zone faults” and maintain stability for any faults outside the protected zone, even with fully saturated *CT*.

6.1.6 *Transmission* bus coupler and bus section protection

Bus-coupler and bus-section panels are equipped with *O/C* protection.

6.1.7 *Transmission* shunt capacitor protection

All the new high voltage capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors shall also be employed to limit inrush current.

The following protection functions shall be provided for all types of protection schemes:

a. Unbalanced protection with alarm and trip stages

b. Over-current protection with instantaneous and definite time elements

c. Earth fault protection with instantaneous and definite time sensitive function

d. Overload protection with *IDMT* characteristic.

e. Over voltage with definite time

f. Circuit breaker close inhibit for 300 seconds after de-energisation

g. Ancillary functions as indicated below.

6.1.8 Over-voltage protection

Primary protection against high transient over-voltages of magnitudes above 140% (e.g. induced by lightning) shall be provided by means of surge arrestors. To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage protection shall be installed on shunt capacitors and feeders.

Over-voltage protection on shunt capacitors is set to disconnect capacitor at 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients.

Over-voltage protection on the feeders is set to trip the local breaker at voltage level of 120% with a delay of 1 to 2 seconds.

6.1.9 Ancillary protection functions

Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between protection devices and with bay equipment. The *TNSP* shall consider the following functions for all new protection system designs:

a. Breaker Fail / Bus trip

b. Breaker Pole Discrepancy

c. Breaker Anti-pumping

d. Pantograph Isolator Discrepancy (Pole discrepancy applied to Isolators)

e. Master trip/lockout

6.2 System protection requirements

6.2.1 Under-*frequency* load shedding

The actions taken on the power system during an under-*frequency* condition is defined in the System Operation Code.

Under-*frequency* load shedding relays shall be installed in the *IPS* as determined by the *SO* in consultation with *distributors* and *end-use customers*. The respective asset owners shall pay for the installation and maintenance of these relays.
Under-*frequency* relays shall be tested periodically. *Distributors* and *end-use customers* shall submit to the *SO* a written report of each such test, within a *month* of the test being done, in the format specified in the *Information* Exchange Code.
The provisions of the *SAPP* operating guidelines shall prevail over the provisions of this section in the event of conflict.

6.2.2 Out-of-step tripping

The purpose for the out-of-step tripping protection is to separate power system in a situation where a loss of synchronous operation takes place between a *unit* or *units* and the main power system. In such a situation system separation is desirable to remedy the situation. Once the islanded system is stabilized it can be reconnected to the main system.

The *SO* shall determine and specify the out-of-step tripping (*OST*) functionality to be installed at selected locations by the *TNSP*.

6.2.3 Under-voltage load shedding

Under-voltage load shedding protection schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads is carried out to arrest the slide.

The *SO* shall determine and specify the under voltage load shedding functionality to be installed at selected locations by the *TNSP*.

6.3 Protection system performance monitoring

TNSP shall monitor protection performance.

Each protection operation shall be investigated for its correctness based on available *information*. The *TNSP* shall provide a report to *end-use customers* affected by a protection operation when requested to do so.

7 Nomenclature

All safety terminology shall comply with the ZS418 Electrical Safety – Code of Practice.

Engineering drawings relating to connecting equipment shall use the symbol set and layout conventions as defined in Appendix 1.

8 *TS* planning and development

This section specifies the technical, design and economic criteria and procedures to be applied by the *TNSP* in the planning and development of the *TS* and to be taken into account by *end-use customers* in the planning and development of their own systems. It specifies *information* to be supplied by *end-use customers* to the *TNSP*, and *information* to be supplied by the *TNSP* to *end-use customers*.

8.1 Planning process

The *TNSP* shall follow a planning process divided into major activities as follows:

a. Identification of network requirements.

b. Formulation of alternative options to meet this need.

c. Studying these options to ensure compliance with agreed technical limits, and justifiable reliability and QOS standards.

d. Costing these options on the basis of present-*day* capital costs and using appropriate net discount rates, establish the net present cost of each option.

e. Determining the preferred option.

f. Building a business case for the preferred option using the approved justification criteria.

g. Requesting approval of preferred option and initiating execution.

8.2 Forecasting the demand

The *SO* is responsible for producing the *TS* demand forecast for the next fifteen years and updating it annually.

The *TS* demand forecast shall be determined for each *point of supply*.

The *SO* shall forecast the maximum demand in *MW* for each *transmission substation* and the result shall be reconciled with data from *participants*.

All *distributors* and *end-use customers* shall annually, by end of October, supply their 15-year-ahead load forecast data as detailed in the *Information* Exchange Code.

8.3 Technical limits and targets for planning purposes

The limits and targets against which proposed options are checked by the *TNSPs* shall include technical and statutory limits, which must be observed.

8.3.1 Voltage limits and targets

Technical limits are stated in table 8.3.1:

<table>
<tr><th>Voltage level
V</th><th>Compatibility level
%</th></tr>
<tr><td>< 11000</td><td>± 10</td></tr>
<tr><td>≥ 11000</td><td>± 5</td></tr>
<tr><td colspan="2">NOTE — In the absence of any agreement to the contrary, the supply voltage shall not deviate from the compatibility level for any period longer than 10 consecutive minutes.</td></tr>
</table>

TABLE 8.3.1 TECHNICAL VOLTAGE LIMITS

8.3.2 Other targets for planning purposes

8.3.2.1 *Transmission* Lines

Thermal ratings of standard *transmission* lines shall be determined and updated from time to time. The thermal ratings shall be used as an initial check of line overloading. If the limits are exceeded the situation shall be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

8.3.2.2 Transformers

Standard transformer ratings shall be determined and updated from time to time using *IEC* specifications. If target loads are exceeded the specific situation shall be assessed as it may be possible to defer adding extra transformers.

8.3.2.3 Series Capacitors

With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.

Cyclic overload capabilities shall follow the provisions of *IEC* 143
The particular rating to be used must match the duration of the contingency with the required overload capability. Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

Any *TNSP* wishing to install a new series capacitor or modify the size of an existing series capacitor, shall arrange for sub synchronous resonance, harmonic and protection coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any *generator*.

8.3.2.4 Shunt Reactive Compensation

Shunt capacitors shall be able to operate at 30% above their nominal rated current at nominal voltage to allow for harmonics and also for voltages up to the maximum level allowable.

Any *participant* wishing to install or modify such equipment shall at his expense arrange for harmonic resonance studies to be conducted. If such studies indicate possible harmonic resonance conditions, which could impact on the *TS*, such *party* shall inform the *SO* before proceeding with the installation or modification.

8.3.2.5 Circuit Breakers

These ratings, and the following limits specified for circuit breakers, shall not be exceeded:

a. Single-phase breaking current: 1.15 times 3 phase fault current

b. Peak making current: 2.55 times 3 phase rms fault current

8.3.2.6 Secondary arc current during single-phase reclosing

The secondary arc current shall not exceed:

a. 20 amps rms with recovery voltage of 0.4 pu

b. 40 amps rms with recovery voltage of 0.25 pu

8.3.3 Reliability criteria for planning purposes

The *TNSPs* shall formulate long-term plans for expanding or strengthening the *TS* on the basis of the justifiable redundancy.

8.3.4 Contingency criteria for planning purposes

A system meeting the n-1 (or n-2) contingency criterion must comply with all relevant limits outlined in 8.3.1 (voltage limits) and the applicable current limits, under all credible system conditions.

For contingencies under various loading conditions it shall be assumed that appropriate, normally used, generating plant is in service to meet the load and provide spinning reserve. For the more probable n-1 network contingency the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable n-2 network contingency an average pattern shall be used. More details of load and generation assumptions for load flow studies are given in section 8.3.5.

8.3.5 Integration of *Power Stations*

When planning the integration of *Power Stations* the following criteria shall apply:

8.3.5.1 *Power stations* of less than 1000 *MW*

a. With all connecting lines healthy it shall be possible to transmit the total output of the *power station* to the system for any system load condition. If the local area depends on the *power station* for voltage support, connection shall be done with a minimum of two lines.

b. Transient stability shall be maintained following a successfully cleared single phase fault

c. If only a single line is used it shall be able to be selected to alternative busbars and be able to go on to bypass at each end of the line

8.3.5.2 Transient stability

Transient stability shall be retained for the following conditions:

a. a three-phase, line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous *power station* loading condition, or

b. a single phase fault cleared in "bus strip" times, with the system healthy and the most onerous *power station* loading condition, or

c. a single-phase fault, cleared in normal protection times, with any one line out of service and the *power station* loaded to average availability.

8.3.5.4 *Busbar* arrangements

Bus-bar layouts shall allow for selection to alternative *bus-bars* and the ability to go on to by-pass.

8.3.6 Least economic cost criteria.

When investments are made in terms of improved supply reliability and/or quality, this would be the preferred method to use. This methodology should also be used to determine and/or verify the desired level of network or equipment redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the cost of interruptions, load shedding, network constraints, poor quality of supply, etc. Statistical analysis of network *outages* is also required.

The least-cost investment criterion equation to be satisfied can be expressed as follows:

Value of improved *QOS* to *end use customers*	**>**	**Cost to the service provider to provide improved *QOS***

From the equation above it is evident that if the value of the improved *QOS* to the *end-use customer* is less than the cost to the service provider, then the service provider should not invest in the proposed project(s).

Equation above can be stated differently as:

Annual value (US$/kWh) x Reduction in *EENS* to Consumers (kWh)	**>**	**Annual cost to the service provider to reduce *EENS* (R)**

The reduction in *EENS* is calculated on a probabilistic basis based on the improvements derived from the investments

The cost of unserved energy is a function of the type of load, the duration and *frequency* of the interruptions, the time of the *day* they occur, whether notice is given of the impending interruption, the indirect damage caused, the start-up costs incurred by the consumers, the availability of *end-use customer* back-up generation and many other factors.

Figure 7.5.2 (a) indicates the concept of a load profile, while figure 7.5.2 (b) indicates the energy not served. This is in the event of a load growing to 125 *MVA* whereas the firm transformer rating is 100 *MVA*.

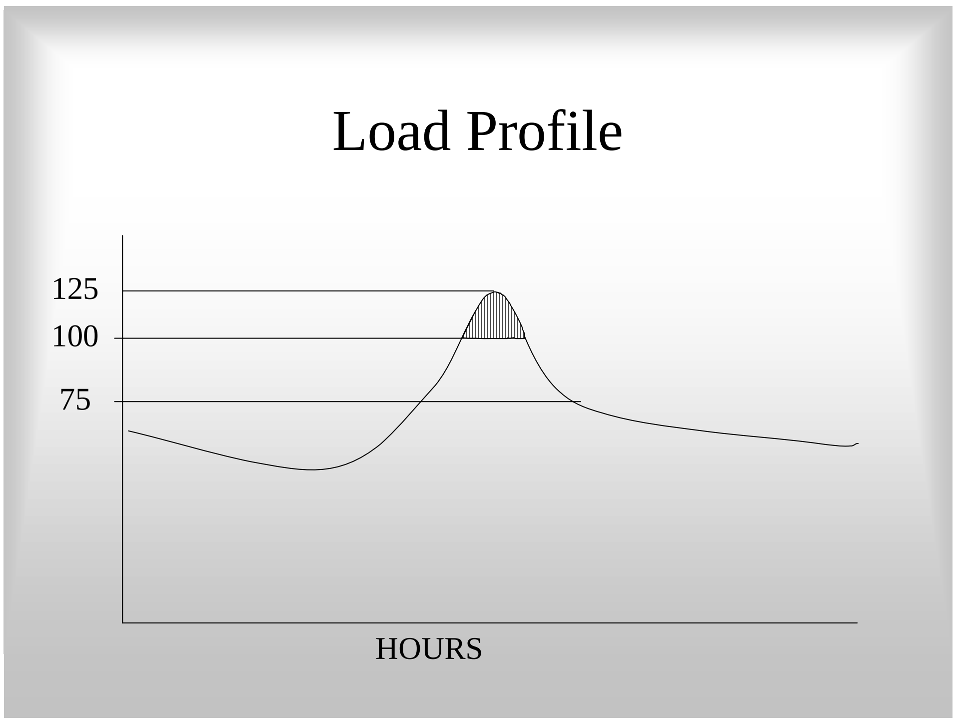


Figure 7.5.2 (a): Typical load profile

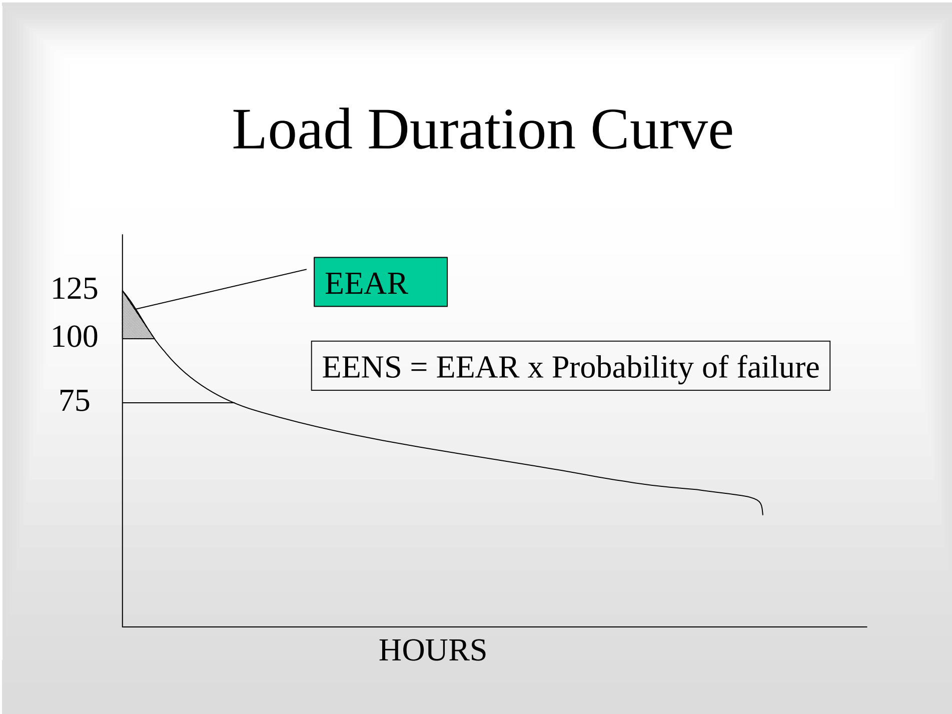


Figure 7.5.2 (b): Load duration curve

8.3.7 Cost reduction investments

Proposed expenditure which is intended to reduce *service providers'* costs (for example, shunt capacitor installations, telecommunication projects and equipment replacement which reduce costs, external telephone service expenses and maintenance costs respectively) or the cost of *losses* or other *ancillary services*, should be evaluated in the following manner:

Firstly, it is necessary to calculate the *NPV* of the proposed investment using the *DCF* methods. This should be done by considering all cost reductions (e.g. savings in system *losses*) as positive cash flows, off-setting the required CAPEX. Once again, *sensitivity analysis* with respect to the amount of CAPEX (estimated contingency amount), the *Annual Average Incremental Cost Of Generation (AAICOG)* (when appropriate) and, future load growth scenarios is required. As before, a resulting positive *NPV* indicates that the investment is justified over the expected life of the proposed new asset.

However, a positive *NPV* does not always indicate the optimal timing for the investment. For this reason, the second portion of the cost reduction analysis is necessary. It remains necessary to ascertain if the annual extra costs incurred by the service provider for owning and operating the proposed asset is less than all cost reductions resulting from the new asset in the first year that it is in service.

8.3.8 Statutory or strategic investments

This category of projects includes the following:

a. Investments formally requested by the Government of the Republic of Zambia.
b. Projects necessary to meet environmental legislation.

c. Possible compulsory contractual commitments.

d. Servitude acquisition

This category shall not be used for justifying projects that are merely not of economic benefit.

8.4 Development investigation reports

The *TNSPs* shall compile, before any development of the *TS* is approved, a detailed development investigation report. The report shall be used as the basis for making the investment decision and shall as a minimum contain the following elements:

a. A description of the problem/request

b. Alternatives considered (including non-*transmission* or capital) and an evaluation of the long-term costs/benefits of each alternative.

c. Detailed techno-economic justification of the selected alternative according to the approved investment criteria.

8.5 *Transmission* investment plan

The *TNSPs* shall annually publish a five-year ahead network investment plan, indicating the major capital investments planned (but not yet necessarily approved).

This plan shall be based on all *end use customer* requests received at that time, as well as *TNSPs* initiated projects.

8.6 Mitigation of network constraints

The *TNSPs* has the obligation to resolve network constraints.

Network constraints ("congestion") shall be regularly reviewed by the *TNSPs*. Economically optimal plans shall be put in place around each constraint, which can involve investment, the purchase of the *constrained generation ancillary service* or other solutions.

8.7 Interfacing between *participants*

The *TNSPs* shall ensure regular interfacing with *end-use customers* regarding network development. One objective shall be to achieve overall optimal plans, ensuring economically efficient investment.

8.8 Special *end use customer* requirements for increased reliability

Should an *end-use customer* require a more reliable connection than the one provided by the *TNSPs*, and if the *end-use customer* is willing to pay the total cost of providing the increased reliability, the *TNSP* shall meet the requirements at the lowest overall cost.

9 Network maintenance

Participants shall monitor the performance of their plant and take appropriate action where deteriorating trends are detected.

Maintenance *scheduling* shall be done in accordance with the System Operation Code.

The *TNSP* shall agree in writing with its *end-use customers*, details of any special maintenance requirements as well as maintenance coordination requirements per *transmission* substation. The *TNSP* shall provide *end-use customers* with details of its maintenance plans and practices upon request.

Appendix 1 ***Transmission* drawings symbol set and layout conventions**

IEC 60617 “Graphical symbols for diagrams” or an appropriate Zambian standard shall be used as the standard for electrical drawings, unless otherwise agreed between a service provider and a *customer*.

Appendix 2 Surveying, monitoring and testing for generators

A.1 Introduction

This section specifies the procedures to be followed in carrying out the surveying, monitoring or testing to confirm the:

a. compliance by *power stations* with the *ZGC*

b. provision by *power stations* of *ancillary services* which they are required or have agreed to provide.

A.2 Scope

This code applies to *generators*.

A.3 Request for surveying, monitoring or testing

The *SO* may issue an instruction requiring a *power station* to carry out a test, at a time no sooner than 48 hours from the time of the instruction, to demonstrate that the relevant power station complies with the *GCRS*.

A.4 Ongoing Monitoring of a *Unit's* Performance

A *generator* shall monitor each of its *units* during normal service to confirm ongoing compliance with the applicable parts of this code. Any confirmed deviations detected must be reported to the *SO* within 2 working *days*.

A *generator* shall keep records relating to the compliance by each of its *units* with each section of this code applicable to that *unit*, setting out such *information* that the *SO* or *TNSP* reasonably requires for assessing power system performance under normal and abnormal conditions.

A *generator* shall provide to the *SO* a report, in January of each year, detailing the compliance by each of that *generator's units* with every section of the code during the past 12 *month* period. The template for this report is attached as an Appendix 3 in the *Information* Exchange Code.

A.5 Procedures

A.5.1 *Unit* Protection System - GCR 1

APPLICABILITY AND FREQUENCY

Prototype study: All new *power stations* coming on line or *power stations* where major refurbishment or upgrade of protection systems have taken place.

Routine review: All *power stations* every 5 to 6 years.

PURPOSE

To ensure that the relevant protection requirement in the *power station* is co-ordinated and aligned with the system requirements.

PROCEDURE

***Prototype*:**

1. Establish the System protection function and associated trip level requirements from *TNSP* and the records with the SO.
2. Derive protection functions and settings that match the *power station* plant, *transmission* plant and system requirements.
3. Confirm the stability of each protection function for all relevant system conditions.
4. Document the details of the trip levels, stability calculations for each protection function.
5. Convert protection-tripping levels for each protection function into per *unit* base.
6. Consolidate all settings in per *unit* base for all protection functions in one document
7. Derive actual relay dial setting details and document the relay setting sheet for all protection functions.
8. Document the position of each protection function on one single line diagram of the generating *unit* and associated connections.
9. Document the tripping functions for each tripping function on one tripping logic diagram.
10. Consolidate detail setting calculations, per *unit* setting sheets, relay setting sheets, plant base *information* the settings are based on, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers *information* into one document.
11. Submit to *TNSP* and *SO* for their acceptance and update.
12. Provide *TNSP* and *SO* with one original reference copy and one working copy.

***Review*:**
1. Review Items 1 to 10 above.
2. Submit to *TNSP* and *SO* for their acceptance and update.
3. Provide *TNSP* and *SO* with one original reference copy and one working copy.

ACCEPTANCE CRITERIA
All protection functions are set to meet the necessary protection requirements of the *transmission network* and *power station* plant with minimal margin. Optimal fault clearing times, and maximum plant availability.

Submit a report to *TNSP* and *SO* one *month* after commissioning for prototype study or 5 to 6 yearly for routine tests.

Parameter	Reference
Protection Integrity Tests	**APPLICABILITY** ***Prototype test***: All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. ***Routine test:*** All *Power Stations* 5 to 6 yearly or after major overhaul of plant. **PURPOSE** To confirm that the protection has been wired and function according to the specified. **PROCEDURE** 1. Apply final settings as per agreed documentation to all protection functions. 2. With the generator *unit* off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. *HV* Breaker). Document all trip test responses. 4. Apply short circuits at all relevant protection zones and with generator at nominal speed excite generator slowly, record currents at all relevant protection functions, and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short circuits. With the generator at nominal speed, excite generator slowly recording voltages on all relevant protection functions. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses. **ACCEPTANCE CRITERIA** All protection functions fully operational and operate to required levels within the relay OEM allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to traceable standard. 5. Submit a report to *TNSP* and *SO* one *month* after test.

A.5.2 Excitation System Grid Code Requirement GCR 2	
Parameter	**APPLICABILITY AND FREQUENCY**
Excitation and Setting Integrity Study	***Prototype study:*** All new *power stations* coming on line or *power stations* where major refurbishment or upgrade of protection systems have taken place. ***Routine review:*** All *power stations* every 5 to 6 years. **PURPOSE** To ensure that the Excitation systems in the *power stations* is co-ordinated and aligned with the system requirements. **PROCEDURE** ***Prototype:*** 1. Establish the System excitation system performance requirements from *TNSP* and *SO*. 2. Derive a suitable model for the excitation system according to *IEEE*421.5 or IEC 60034.16.2. Where necessary, non standard models (non *IEC* or *IEEE*) shall be created. This may require *frequency* response and bode plot tests on the excitation system as described in *IEEE* 421.2.1990. 3. Submit the model to *TNSP* and *SO* for their acceptance. 4. Derive excitation system settings that match the *power station* plant, *transmission* plant and system requirements. This includes the settings of all parts of the excitation system such as the chop-over limits and levels, limiters, protection devices, alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions system conditions. 6. Document the details of the trip levels, stability calculations for each setting and function. 7. Convert settings for each function into per *unit* base and produce a high-level dynamic performance model with actual settings in p.u. values. 8. Derive actual card setting details and document the relay setting sheet for all setting functions.

	9. Produce a single line diagram / block diagram of all the functions in the excitation system and indicate signal source. 10. Document the tripping functions for each tripping on one tripping logic diagram. 11. Consolidate detail setting calculations, model, per *unit* setting sheets, relay setting sheets, plant base *information* the settings are based on, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers *information* into one document. 12. Submit to *TNSP* and *SO* for their acceptance and update by providing them with one original master copy and one working copy. ***Review:*** Review Items 1 to 10 above. Submit to *Transmission* for their acceptance and update. Provide *Transmission* with one original master copy and one working copy update if applicable. **ACCEPTANCE CRITERIA** Excitation system is set to meet the necessary control requirements in an optimized manner for the performance of the *transmission* and *power station* plant. Excitation system operates stable both internally and on the network. Submit a report to *TNSP* and *SO* one *month* after commissioning for prototype study or 5 to 6 yearly for routine tests, within one *month* after due date expiry.

Parameter	
Excitation Response Tests	**APPLICABILITY** ***Prototype test:*** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. ***Routine test:*** All *Power Stations* 5 to 6 yearly or after major overhaul of plant. ***Prototype test***: All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. ***Routine test:*** All *Power Stations* 5 to 6 yearly or after major overhaul of plant. **PURPOSE** To confirm that the excitation system performs as per designed and installed. **PROCEDURE** With the generator off line, carry out *frequency* scans / bode plot tests on all circuits in the excitation system critical to the performance of the excitation system. With the generator in the open circuit mode, carry out the Large signal performance testing as described in *IEEE* 421.2 of 1990. Determine Time response, Ceiling voltage, voltage response, • With the *generator* connected to the network and loaded, carry out the small signal performance tests according to *IEEE* 421.2.1990. Also carry out power system stabiliser tests and determine damping with and without Power System stabiliser. Document all responses. **ACCEPTANCE CRITERIA** Excitation system meets the necessary control requirements in an optimised manner for the performance of the *transmission* and *power station* plant as specified. Excitation system operates stable both internally and on the network. Power System stabilisers set for optimised damping.

A.5.3 *Unit* Reactive Power Capability *GCR* 3	
Parameter	**APPLICABILITY**
Reactive Power Capability	***Prototype test***: All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. **PURPOSE** To confirm that the reactive Power Capability specified are met. **PROCEDURE** The duration of the test will be for a period of up to 60 minutes during which period the System voltage at the Grid Entry Point for the relevant Generating *Unit* will be maintained by the *Generator* at the voltage specified by adjustment of Reactive Power on the remaining Generating *Units* , if necessary. **ACCEPTANCE CRITERIA** Generating *Unit* will pass the test if it is within ±5% of the capability registered with *TNSP* and *SO* Submit a report to *TNSP* and *SO* one *month* after test.

A.5.4 *Governing* System *GCR* 4.	
Parameter	**APPLICABILITY**
Governing Response Tests	***Prototype test***: All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. ***Routine test:*** All *Units* to be monitored continuously, additional tests may be requested by the *SO* **PURPOSE** Prove the *unit* is capable of the minimum requirements required for *Governing* **PROCEDURE** 1. *Frequency* or speed deviation to be injected on the *Unit* for 10 minutes. 2. Real Power Output of the *Unit* is to be measured and recorded. **ACCEPTANCE CRITERIA** Minimum requirements of the *ZGC* are met

A.5.5 Black Start Capability *GCR* 5	
Parameter	**APPLICABILITY** ***Routine Test:*** *Power stations* that have contracted under the ancillary services to supply station *Black start* services. When called for by *SO* but not more than once every 2 years **PURPOSE** Demonstrate that a *power station* has *Black Start* Capability **PROCEDURE** • The relevant Generating *Unit* shall be Synchronised and Loaded; • All the Auxiliary generators in the station in which that Generating *Unit* is situated, shall be Shutdown. • The Generating *Unit* shall be De-Loaded and De-Synchronised and all AC electrical supplies to its Auxiliaries shall be disconnected. • The station shall then execute its *Blackstart* Procedure and restart the relevant Generating *Unit*, Synchronise it to the System and wait for loading instructions to be given by *SO*. All *Black Start* Tests shall be carried out at the time agreed with the *SO* and shall be undertaken in the presence of TNSP and SO representatives, who shall be given access to all *information* relevant to the *Black Start* Test. **ACCEPTANCE CRITERIA** A *Black Start* Station shall fail a *Black Start* Test if the *Black Start* Test shows That it does not have a *Black Start* Capability (i.e. if the relevant Generating *Unit* Fails to be Synchronised to the System within thirty (30) minutes of the commencement of the Blackstart procedure. A written report shall be submitted to the SO and *TNSP* one *month* after test.
Black Starting	

APPENDIX 3: STANDARD APPLICATION FORM FOR *TRANSMISSION* CONNECTION

1.0 GENERAL

Company Name:
Company Registration No.:

Issued by Registrar of companies

Customer's Physical address

Customer's Physical Location

Postal Address

Customer's Preferred Postal address

***Customer* Contact Person**	
Job Title:	
Name: (Initials & Surname)	
Telephone 1:	
Telephone 2/ Cell:	
Fax:	
Email address:	

Physical connection to the *Transmission* system required? (Y/N):
IF NOT INDICATE NATURE OF BUSINESS :

Application Date:	**/ /**

Customer's initial application date: dd – mm – yyyy

Requested Completion Date	/ /

When *customer* wants supply available: dd – mm – yyyy

Phasing if plant development is proposed in phases

Phase 1	
Phase 2	
Phase 3	

dd – mm – yyyy

2. PLANT – ELECTRICAL

Desired Connection Voltage (kV):	MVA:

Capacity of Connection required (MVA)

Estimated Monthly Consumption:	MWh	Declared Peak Load: MW

Highest average no. of MW to be supplied in any consecutive 30 minutes

Overall Plant Power Factor:		Limitations on Harmonics:

Emergency loading requirements if any:	MW

(For man winders, pumping and ventilation in case of total loss of supply)

Short Circuit Levels: MVA	MVA
	State if there are any requirements for the minimum fault level desired at *Point-Of-Supply*

Standard or Enhanced Reliability Connection:	

Temporary Connection:	**Owner or Tenant:**
If short term: period (*months*) for which connection required	*Customer* owns/ rents property for this application

3. ADDITIONAL *INFORMATION*

***Point of Supply*/Physical Connection Address:**

Full description of the property/title deed where supply is required: Street address, lot no. etc No Postal addresses

Usage category (please tick):

Industrial:	**Commercial:**	**Distribution:**
Generation:	**International:**	
Other (please specify):		

Nearest Existing *Transmission System* Connection:	

Transmission substation closest to requested Point of supply

Other *Transmission* System Connections:	

Does *customer* have other *Transmission* Connection Points of Supply

Special Instructions:

Customer's additional *information* regarding application

Note that further *information* may be required before a quote can be provided, as described in the Grid Code

Cancel Date and Reason:

dd – mm – yyyy

4. TO BE FILLED IN BY SERVICE PROVIDER

Customer ID:	Existing *Customer*:
Transmission-generated unique *customer* number	
Parent *Customer* ID:	*Customer* Type:
Indicates if *customer* is subsidiary to existing *customer*	Indicate Individual/ Company/Partnership/ Other
Application ID:	POS ID:

Unique No. for current application	Unique No. applicable to Point-of-Supply

Application Type ID					
NEW	**INCR.**	**DECR.**	**CHANGE**	**LINES**	
New POS/ Connection	Increase of Connection to:	Decrease of Connection to:	Change of *Customer* only	Existing Lines to be moved	
MVA	MVA	MVA	MVA	MVA	MVA
Size supply req.	Size supply req.	Size supply req.	Current supply	Current supply	Size supply req.

Note: Only 1(one) Application Type ID per Application

Priority Request Indicator:	Priority Request Reason:
High/ Medium/ Low	Motivation required for 'High' or 'Low" indicators
Project ID:	Ref No/s
	Details of any other *transmission* POS's linked to this *customer*
Quotation Date: / /	Agreement Date: / /
Date on which application completed dd-mm-yyyy	Date agreement completed dd-mm-yyyy
Connection Fee Amount:	Connection Fee Payment Date: / /
	Date agreement completed dd-mm-yyyy
Connection Fee Receipt No.	
Unique No.	

PART 4 - METERING CODE

1 Objective

The *Metering* Code specifies tariff and statistical *metering* requirements for the *ZGC*.

2 Scope

This code shall apply to *metering* points at the boundary of the *TNSPs* and their *customers* and it shall be applicable to:

a. main *metering installations* and check *metering installations* used for the measurement of active and reactive energy;

b. the collection and storage requirements for *metering* data;

c. the provision, installation, maintenance and testing of metering equipment;

d. the standards and accuracy of all *metering* equipment used in the process of electricity *metering*;

e. the relationship of entities involved in the electricity *metering* industry.

3 General Provisions

The *metering* point shall be located at the point agreed between the *participants.*

Customers may request an independent audit of *metering installations*. The requesting *participant* shall be responsible for any costs relating to the audit unless the *metering installation* is proved to be outside the defined standard.

Parties shall provide all the necessary *information* reasonably required to perform their respective *metering* duties.

The type, installation, operation and testing of *metering installation* at each *metering* point shall comply with ZS 647 *metering* specifications.

4 Responsibility for *metering installations*

The *Service Provider* shall ensure that all points identified as *metering* points in accordance with Section 3 have *metering installations* in accordance with the provisions of this code.

The *TNSP participants* shall be responsible for managing and collecting *metering information*.

Participants connected to or intending to *connect to the TS* shall provide the relevant *service provider* with all *information* deemed necessary to enable performance of its *metering* duties.

The *participants* shall ensure that commissioning, maintenance, auditing and testing of *metering installations* are carried out in accordance with ZS 647.

5 Metering installation **requirements**

a. Each *metering* point shall be installed with main and check *metering*.

b. Both active and reactive energy shall be measurable without compromising any requirements of this code.

c. Full four quadrant *metering* shall be installed where active and reactive energy flow is in both directions.

d. The meters shall be configured to store/record *metering data* in half hourly integration periods.

e. The meter(s) or recorder(s) shall be able to store *data* in memory for at least 40 *days*.

f. The *service provider* shall provide historical *metering data* to the *customers* on request.

g. The *service provider* shall provide real time *metering data* when requested to do so by the *customer* provided that this is practicably possible. The *customer* shall bear the cost of this installation.

h. A *customer* may install own *metering* in a *service provider*'s installation

6 *Data* validation

The *participants* shall carry out *data* validation in accordance with ZS 647

In the event of:

a. Electronic access to the meters not being possible;

b. An *emergency* bypass or other scheme having no *metering* system; or

c. *Metering data* not being available

The participant's officer responsible for *metering* may resort to any of the following:

i. Manual meter *data* downloading

ii. Estimation or substitution subject to mutual agreement between the affected *parties*

iii. Profiling

iv. Reading of the meter at scheduled intervals

When the need for *metering* estimations arises, the estimates will be done in accordance with ZS 647.

7 Meter verification

In addition to the ZS 647 verification requirements, meter readings shall be compared with the *metering* database at least once a year.

8 *Metering* database

The *service provider* shall create, maintain and administer a *metering* database containing the following *information*:

a. Name and unique identifier of the *metering installation*

b. The date on which the *metering installation* was commissioned

c. The connecting parties at the *metering installation*

d. Maintenance history schedules for each *metering installation*

e. Telephone numbers used to retrieve *information* from the *metering installation*

f. Type and form of the meter at the *metering installation*

g. Fault history of a *metering installation*

h. Commissioning documents for all *metering installations*

The *service provider* shall retain *metering information* for at least five years for audit trail purposes.

9 *Metering* database inaccuracies

In the event of test results revealing that *data* in the *metering* database is inaccurate, the *service provider* shall inform all affected *participants* and corrections shall be made to the official *metering data* and the associated billing by mutual agreement.

10 Access to *metering data*

The service provider shall make *metering* data available to affected *participants* in the format agreed upon.

Service providers shall publish all *data* in the formats agreed upon to all *participants*. All new formats shall be negotiated between the *service provider* and the affected *participants*. The *service provider* shall store all *customer information* in a database and shall ensure that the database is maintained and updated continuously.

The *service provider*, at the expense of the requesting *party* shall provide non-standard *data* provision methods.

All security requirements for *metering data* shall be as specified in ZS 647.

11 Confidentiality

Metering data for use in energy trading and billing are confidential *information* and shall be treated in accordance with the *Information* Exchange Code.

PART 5 - SYSTEM OPERATION CODE

1 Objective

The objective of the System Operation Code is to ensure co-ordinated operation of the *IPS* in order to achieve a high level of system reliability, safety and *security*.

2 Scope

This Code specifies the responsibilities of *participants* in relation to *IPS* operational issues such as:

a. reliability, *security* and safety;

b. Co-ordination of planned equipment *outages* and maintenance.

c. operation of the *IPS* under normal and abnormal conditions;

d. a*ncillary services*;

e. independent actions required and allowed by *customers*;

f. Market operation actions required by the *SO*

4 Responsibility

The *SO* shall be responsible for the safe and efficient operation of the *IPS*.

All *participants* shall set up operational procedures for their respective networks to ensure safe and efficient operation of the *IPS*.

International tie-line operations shall be governed by SAPP and other agreements.

5 *SO* responsibilities

The *SO* shall be responsible for the following:

5.1 System reliability, safety and *security*

a. The *SO* shall operate the *IPS* to achieve the highest degree of reliability practicable. Where there is a fault, remedial action shall be taken promptly to address any abnormal condition that may jeopardise the reliability and safety of the system.

b. The *SO* shall dispatch generation on the *IPS* subject to constraints of *security*, reliability and the environment.

c. The *SO* shall endeavour to retain international interconnections unless it becomes evident that continued parallel operation would jeopardise the integrity of the *IPS*.

d. Where it is unsafe to operate *units* in parallel with the system when critical levels of *frequency* and voltage result on the *IPS* from a disturbance, the *SO* shall ensure that separation and/or safe shut down of *units* shall be accomplished in such a way as to minimize the time required to resynchronise and restore the system to normal.

e. During or after a system disturbance, high priority shall be given to keeping all synchronised *units* running and connected to the *IPS*, or *islanded* on their own auxiliaries, in order to facilitate system restoration

f. Where there is loss of all generation and interconnections with neighbouring countries, *blackstart* services shall be contracted with at least two suitable facilities.

g. In the event of severe contingency, the *SO* shall ensure that instability, uncontrolled separation or cascading *outages* do not occur.

h. The *SO* shall be responsible for restoration of the *TS* after supply *interruptions,* in accordance with the restoration procedures for the *IPS*.

i. In the event of system disturbances, the *SO* shall endeavour to minimise adverse effects on *customers.*

j. The *SO* shall operate and maintain primary and backup *control centers* and associated facilities to ensure continuous operation of the *IPS*.

5.2 *Operational measures*

The *SO* shall establish and implement operating instructions, procedures and guidelines to cover the operation of the *IPS* under all system conditions. The *SO* shall maintain a database with version control of all such documents.

a. The *SO* shall operate the *IPS* within its normal rating and defined technical standards.

b. The *SO* shall manage constraints on the *TS* through the determination of operational limits and the purchase of the *constrained generation ancillary services* where applicable.

c. The *SO* shall co-ordinate maintenance schedules of plant and equipment on the *IPS* and ensure that subsequent *planned outages* do not violate the reliability criteria of the *IPS*.

d. The *SO* shall ensure adequate and reliable communication between all *control centres*, *power stations* and *substations*. Communications facilities to be provided and maintained by the *customers* are specified in the *Information* Exchange Code.

e. The *SO* shall ensure the establishment of a common protection philosophy for the *TS* as required by the Network Code.

f. The *SO* shall review protection settings on the *IPS*, after system alterations, and shall maintain an updated database of these settings.

6 ***Scheduling* of Generation and Ancillary Services**

a. The *SO* shall develop daily twenty-four hours (24) *day*-ahead energy and *ancillary services* schedule before 14:00 each *day*.

b. The *SO* shall be responsible for executing and rescheduling of the energy and *ancillary services* schedule.

7 Ancillary services

a. The *SO* shall be responsible for the provision of all short-term reliability services for the *IPS*.

b. The *SO* shall determine reliability targets for the purpose of acquiring *ancillary services* in consultation with affected *participants*. The reliability targets shall be selected so as to minimise the sum of the cost of providing the reliability plus the cost to the *customer* of limited reliability. The cost of providing suitable ancillary service levels shall be calculated annually for budgetary purposes.

c. The *SO* shall be responsible for procuring the required *ancillary services* needed to provide the required reliability.

8 Operational authority

The *SO* shall have the authority to issue operational instructions over the *TS*. Operational authority for other networks on the *IPS* shall lie with the respective *Regional Operators*.

Network control at the interface between the *TNSP* and a *customer* shall be in accordance with the operating agreements between the *participants*.

Except where otherwise stated in this section, no *participant* shall be permitted to operate the equipment of another without the permission of such other *participant*. In such an event the asset owner shall have the right to test and authorise the relevant operating staff in accordance with his own standards before such permission is granted.

Not withstanding the provisions of Section 5, *participants* shall retain the right to safeguard the health of their equipment.

9 Operating procedures

The *SO* shall develop and maintain operating procedures for the safe operation of the *TS* and for assets *connected to the TS* .

All participants shall submit names of authorized personnel to *SO* and *Regional Operator.*

Each *customer* shall comply with ZS418 Electrical Safety – Code of Practice and other relevant safety legislation and in doing so may develop in-house safety regulations.

The *SAPP* operating agreements shall apply in the case of operational liaison with all international power systems connected to the *TS*.

10 Operational liaison

The *SO* shall sanction the shutting down and synchronising of *units.*

If any *participant* experiences an *emergency*, the other *participants* shall assist to the extent possible as may be necessary to ensure that it does not jeopardise the operation of the *IPS* or health of plant.

Whenever possible *end-use customers* may be required to transfer load from one *point of supply* to another by performing switching operations on the network.

The *TNSP,* in consultation with a specific *generator*, shall compile a comprehensive maintenance, test and inspection plan for all equipment, systems and schemes installed in the specific *HV* yards*.*
The *TNSP* shall provide notification to *generators* of any work to be carried out on any protection, control and instrumentation circuits in adjacent *HV* yards*.* The *TNSP* shall compile re-commissioning programs for such work in consultation with the *generator.*

The *TNSP* and *customers* shall agree on the bus-bar configuration(s) at each *point of supply* during normal and *emergency* conditions. Details of such configuration(s) shall be included in the operating agreement between the *participants.*

Generators shall inform the *SO* of any environmental limitations that would affect the dispatch of the plant.

11 *Emergency* and contingency planning

The *SO* in conjunction with all *participants* shall develop, implement, maintain and ensure compliance with all contingency and *emergency* plans that are relevant to the performance of the *IPS*. These plans shall be consistent with *Prudent Utility Practices*.

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

All *emergency* plans shall be periodically verified by actual tests to the greatest practical extent. In the event of such tests causing undue risk or undue cost to a *participant,* the *SO* shall take such risks or costs into consideration when deciding whether to conduct the tests. The cost of these tests shall be borne by the respective asset owners. The *SO* shall co-ordinate these tests with all affected *participants.*

The *SO* shall be responsible for determining all operational limits on the *TS,* updating them periodically and making them available to the *participants.*

The *SO,* in conjunction with all *Participants*, shall conduct load flow studies annually.

12 *System frequency* and *ACE* control under abnormal *frequency* or imbalance conditions

The *SO* shall be responsible for the balancing of supply and demand in real time through the implementation of the energy schedules and utilisation of *ancillary services*.

12.1 Description of normal *frequency* or balancing conditions

The *IPS* is considered to be under normal *frequency* conditions when:

a. the immediate demand can be met with the available scheduled resources, including any contingency resources;

b. the *frequency* is within the range 49.85 to 50.15*Hz*; and

c. there are no security and/or safety contraventions.

12.2 Operation during abnormal conditions

When abnormal conditions occur, all relevant *participants* shall take corrective actions as stipulated in section 11 of this code.

TABLE 12.2: OPERATION DURING ABNORMAL CONDITIONS

CONDITION FOR USAGE	RESOURCES IN DEFAULT ORDER OF USAGE
Warnings	
WHEN A SHORTFALL IN CAPACITY IS EXPECTED TO OCCUR, ISSUE WARNINGS UNTIL SUFFICIENT CAPACITY IS OBTAINED TO COVER THE SHORTFALL. When there is an appreciable loss of load leading to increased *frequency*, issue warnings until load has been restored.	• *Emergency level generation* warning • load shedding warning • *Emergency* generation reduction • Generation plant shut down
Gradual *frequency* decline	
IF THE *FREQUENCY* FALL BE-LOW 50HZ AND ABNORMAL VOLTAGE CONDITION EXISTS	• Run unscheduled generation *units* • *Interruptible load* shedding • Declare *emergency* to other SAPP *Control Areas*
Rapid *Frequency* Decline	
ENSURE OPERATION OF UNDER-*FREQUENCY* PROTECTION SCHEMES	• Under-*frequency* relay protection schemes

The corrective action includes both supply-side and demand-side options. Where possible, warnings shall be issued by the *SO* on expected utilisation of any contingency resources.

The order in which *emergency* resources are to be used may change from time to time based on contractual arrangement. The *SO* shall issue an updated list of *emergency* resources available annually.

Termination of the use of *emergency* resources shall occur as the plant shortage situation improves and after *frequency* has returned to normal in the order “last in - first out”.

During emergencies that require load shedding, the request to shed load shall be initiated in accordance with agreed procedures prepared and published by the *SO.* Automatic *under-frequency* systems shall be kept armed at all times, apart from gas turbines, which shall be armed by the *SO* when a shortage is expected.

13 Independent action by *participants*

Each *participant* shall have the right to reduce or disconnect a *point of connection* under *emergency* conditions if such action is necessary for the protection of life or equipment. Advance notice of such action shall be given where possible and no financial penalties shall apply for such action.

Following such *emergency* operations as may be necessary to protect the integrity of the *IPS* or the safety of equipment and human life, the *participants* shall work diligently towards removing the cause of the *emergency* and the supply shall be reconnected immediately after the emergency conditions have passed.

14 Voltage control

The *SO* shall be responsible for the voltage control of the *TS*, at *transmission* level voltages as well as at the interface between the *TNSPs* and their *customers*.

TS voltages shall be controlled during normal operation to be within statutory limits at the *points of supply* and otherwise as agreed with *customers*.

15 Fault reporting, analysis and incident investigation

Officers appointed by their respective organisations shall report all incidents that materially affect the QOS on the IPS to other participants.

15.1 *Generators, TNSPs,* Distributors and End-use *Customers*

These participants shall verbally report any loss of output, tripping of *units,* change of status of *AGC* and *governing, loss of transmission capacity or loss of major load* to the *SO* within 15 minutes of the event occurring. This report will be prepared and sent by the control room staff on duty at the time of the incident.

Within seven (7) *days* of a verbally reported incident, a t*hese participants* shall submit a detailed written report to the *SO* that shall take the form of Appendix 1.

Where a *participant* determines that a fault that had occurred on another *participant's system* requires further investigation, the *participant* shall issue an Incident report in accordance with the *Governance code*.

15.2 *SO*

The *SO* shall investigate all incidents that materially affect the QOS on the *IPS*.
Such an investigation shall commence immediately after receipt of a preliminary report and all affected *participants* shall provide required *information* and participate in the investigation.

All participants, within mutually agreed time frames, shall implement recommended actions.

15.3 Root Cause and Forensic Analysis

The *GCTC* will have the mandate to commission a team of Experts to carryout Root Cause Analysis and Forensic Analysis of major incidences and faults on the system.

16 Commissioning

The *SO* shall verify commissioning and maintenance programmes of the *IPS* to ensure co-ordination of activities.

Commissioning of new equipment associated with the *transmission* connection, or re-commissioning of such existing equipment, shall be agreed with the *SO* in writing.
The said aspects shall include, but not be limited to, the following:

a. Commissioning procedures and programmes

b. Documents and drawings required

c. Proof of compliance with standards

d. Documentary proof of the completion of all required tests

e. *SCADA information* to be available and tested before commissioning where such facilities are available

f. Site responsibilities and authorities, etc.

Participants shall give minimum notice period of one *month*, unless otherwise agreed, from the date of receipt of the request for all commissioning or re-commissioning. Where commissioning is likely to involve a requirement for dispatch and/or operating for test purposes, the *participant* shall notify the *SO* of this requirement, including reasonable details as to the duration and type of the testing required.

When commissioning equipment at the *point of connection*, the *TNSP* shall liaise with the affected *customers* on all aspects that could potentially affect the *customers*' operation.

The *TNSP* and *customers* shall perform commissioning tests in order to confirm that *TNSP* and the *customers*' plant and equipment meet the requirements of the *ZGC*.

17 Maintenance coordination / *outage* planning

17.1 *Outage* Management

17.1.1 *Yearly Planned Maintenance Schedule*

Once all submissions have been approved, they shall be consolidated into a yearly maintenance schedule, which shall be circulated to *customers*

The *service providers* shall review all the submissions taking into consideration system *security*, reliability, safety and commercial contracts, before making approval.

If the submissions have not been approved, the *service providers* shall request the *customers* affected to revise their plans and resubmit.

Once all the submissions have been approved, they shall be consolidated into a *Yearly Maintenance Schedule*. Copies of the *Yearly Maintenance Schedule* shall be circulated to all *customers*.

Each *TNSP* shall submit their Yearly Maintenance Schedule to the *SO* for coordination and approval.

17.1.2 Yearly *Unplanned Outages*

If an *unplanned outage* allows time to give notice to the *SO*, this shall be done at least 2 weeks before the *outage*.

When the need for an *unplanned outage* is first identified it shall be communicated to the *service providers* as an *unplanned outage* indicating *outage* dates, times, reason, type of maintenance and urgency assigned to it.

At this point the *Service Provider* shall confirm the *outage* if it satisfies all the necessary requirements.

17.1.3 Effecting of *Outages*

The *SO* shall make available to *customers* an *outage* schedule of all *planned outages* on the *TS*. The *outage* schedule shall cover a period of one calendar year and shall indicate the status of the *outage*, i.e. whether confirmed or not. The schedule shall be updated and republished monthly.

When an *outage* is cancelled or refused it is the responsibility of the person cancelling or refusing the *outage* to furnish reasons for cancellation or refusal, in writing. The person receiving the cancellation or refusal shall then enter this *information* into the system when changing the status to cancelled. This shall also apply to *outages* that are postponed.

17.2 *Emergency Outage*

In the case of *emergency outages* of *customer* equipment, *customers* shall inform *service providers* verbally of the need for the *outage*. However, within 24 hours after the *outage* has been effected, the *outage request* will need to be formalized in formal writing.

S*ervice providers* shall also inform customers in the case of *emergency outages* on their installations.

17.3 Long Term Maintenance Planning for Generators

Generators shall compile an indicative 15-year-ahead maintenance plan in consultation with the *SO* and *TNSP*. The *generator* shall then provide the *SO* with the following documents in the pro-forma format specified in the *Information* Exchange Code.

a. A 52-week-ahead *outage* plan per *power station*, showing *planned outage* and return dates and other known generation constraints, updated weekly by 15:00 every Thursday.

b. An annual maintenance / *outage* plan per *power station*, looking 15-years ahead, showing the same *information* as above and issued by 31 December of each year.

c. A monthly variance report, explaining the differences between the above two reports.

Each *generator* shall ensure the absolute minimum deviation from its annual *outage* plan. Each deviation shall be negotiated with the *SO* and shall be accommodated as far as reasonably practical.

The *SO* shall coordinate network *outages* affecting *unit* output with related *unit outages* to the maximum possible extent.

The objectives to be used by the *SO* in this maintenance coordination are:

i. firstly maintaining adequate reserve levels at all times

ii. secondly ensuring reliability where *TS* constraints exist

iii. thirdly maintaining acceptable and consistent real-time technical risk levels.

The *SO* shall provide forecasting of demand for the next *day*, the next seven *days* (daily) and the next 12 *months* (weekly) to the *generators*.

17.4 Refusal/cancellation of *outages*

No *participant* may unreasonably refuse or cancel a confirmed *outage*. The direct costs related to the cancellation/postponement of an *outage* shall be borne by the participant cancelling/postponing the *outage*.

18 Communication of system conditions, operational *information* and *IPS* performance

The *SO* shall communicate system conditions to all *participants* periodically.

The *SO* shall be responsible for providing *participants* with operational *information* as may be agreed from time-to-time and as specified in the *Information* Exchange Code. This shall include *information* regarding *planned and forced outages* on the *IPS*.

The *SO* shall annually publish expected fault levels, including the rupturing of relevant *TS* equipment, for each *point of supply.*

19 Tele-control

Where telecontrol facilities are shared between the *SO* and other *participants*, the *SO* shall ensure that operating procedures are established in consultation with the *participants*.

APPENDIX 1: Format for Preliminary Incident Report

a. Time of the incident

b. Location

c. Plant and/or apparatus directly involved (and not merely affected by the incident)

d. Description of the incident

e. Demand (MW) and/or generation (MW) interrupted and duration of interruption

f. Generating *unit* – *frequency* response (MW and Hz correction achieved subsequent to the incident)

g. Generating *Unit* – MVAr performance (change in output subsequent to the incident)

h. Change in tie-line flow, where applicable

i. Estimated time and date of return to service

j. Measures taken to prevent/ mitigate recurrence

PART 6 - TRANSMISSION TARIFF CODE

1 Objective

The objective of this code is to promote *Open access* to the *transmission* services at equitable, non-discriminatory prices to all *customers.*

2 Scope

This Code shall apply to *transmission* service pricing for owning, maintaining and operating the *TS*

3 Five-year Pricing Plan

The *TNSP* shall annually publish a five-year rolling forward pricing curve for *transmission* tariffs based on the *TS* development plan as described in the Network Code.

4 Pricing Methodology

The *transmission* tariff shall be *postage stamp*, which shall be based on full cost recovery, fair return on investment, and optimal use of the grid. The *transmission* tariff shall comprise:

a. Individual *Customer* Charges (ICC).

b. *Use of System Charge*s (UoSC) and

4.1 Individual *Customer* Charges

Costs that are attributable to a particular new *customer* such as connection, *metering* and reactive power requirements for *outliers* shall be charged to that *customer*. For existing customers who affect the system stability and reliability in their operation, the cost of procuring ancillary services shall be passed on to them.

The reactive power provision assumes a normal operating system, with *generators* and *consumers* following *GCRs* specified in the Network Code. Where the *customers* do not meet these requirements, then the *TNSP* shall invest in assets and these costs shall be charged to that *customer*.

4.1.1 Connection Charge

The connection charge shall be applicable to both *generators* and *end-use customers* connecting to the *TS* and shall include the following components:

a. Capital charge

b. Return on assets charge

i. **Capital Charge**

The capital charge shall be a percentage of the *GAV,* as may be approved by the *ERB*. The percentage chosen reflects the expected life of the asset and shall ensure that the total cost of the asset value is recovered over time through the capital charge. Examples of assets used at connection points that would feature in a connection charge include, but are not limited to:

- Switchgear used to isolate the supply;
- Transformers used exclusively for the *customer* supply;
- *Transmission* lines;
- *Metering* and protection equipment and associated auxiliaries; and
- Land and buildings for the electrical equipment.

ii. **Return on Assets Charge**

The return on asset charge shall be the finance charge on the asset and shall be a percentage of the *NAV* of the asset*,* as may be approved by the *ERB*.

iii. **Other Charges**

Other charges, which may be incurred at a new or modified connection point, shall be recovered either as a one-off payment or on an annual basis by mutual agreement. Examples of other charges include:

- **One-off works.** This includes the cost of diverting or relocating existing *transmission* assets or removing existing assets.

- **Consents.** This includes the cost of any surveys, legal work, landscaping, appeals, planning inquiries and other related costs.

- **Modifications.** This covers the cost of any modifications at the *customer*'s request.

- **Land.** This covers the cost of any additional land the *TNSP* has to obtain to facilitate the connection.

4.1.2 Shared Connections

Where more than one *customer* is connected at a connection site, then the use of certain connection assets and the corresponding connection charges shall be shared between the *customers* that benefit from those assets. The cost of the shared assets shall be allocated in proportion to the maximum demand of each *customer*.

In the event that more *customers* connect at the same point and the assets were previously determined to be *customer* specific and were paid for through a connection agreement, the new *customer* shall be charged for the use of such assets on a pro rata basis compared with the original *customer*, who shall then receive a rebate based on the payment of the new *customer(s)*.

4.1.3 Termination of Connection

A *customer* wholly or partially disconnecting from the grid shall pay a Termination Charge. The Termination Charge shall take into account the following:

a. The *NAV* of the redundant assets.

b. The reasonable cost of removing such assets, including the cost of any remedial work at the site.

c. In case of shared assets, an amount that protects any remaining *customers* at the site from an increase in capital costs on shared assets not rendered redundant by the termination of the connection.

d. The cost of any previous capital contributions not already recovered.

The above methodology protects remaining *customers* at the site from an increase in capital charges on previously shared assets. If the *TNSP* can reuse a connection asset elsewhere in the system, then the cost of termination would be reduced accordingly.

The methodology for calculating the termination charge shall be specified in the connection contract.

4.2 *Use of System Charge*

Use of System Charges shall be applied for the use of the *transmission* network. They shall reflect the cost of installing, operating and maintaining the *transmission system* for the purposes of accommodating the transfer of bulk power securely and for maintaining prescribed *frequency* and voltage limits. *Use of System Charges* shall incorporate a fixed annual component in the form of a capacity charge and a variable component in the form of an energy charge.

4.2.1 Capacity Charge

The capacity charge shall apply to each *customer* based on their contribution to the overall peak demand on the *transmission system*. Because most of the costs of providing, reinforcing, maintaining and operating the *transmission systems* can not be directly attributable to any particular user, the allocation of these costs shall be based on the maximum demand a *customer* puts on the system. The justification for peak-based charging or cost allocation methods is that *transmission systems* are designed generally to meet peak demand conditions.

Fixed *transmission* and fixed system operation costs shall be charged per *kVA* peak demand. Fixed *transmission* costs shall include costs such as depreciation, interest paid on *transmission* network investments, maintenance and general improvement, wages and salaries, meter reading, meter maintenance, system development,, administration and other fixed costs incurred by *TNSP* plus a fair return on investment for *TNSP.* Fixed system operation costs shall include costs such as depreciation, wages and salaries, administration and other fixed costs The *TNSP* shall apply to the *ERB* for a rate of return to be included as a cost element in the *transmission* tariff calculation. The *SO* shall be reimbursed costs on a cost recovery basis paid by participants through a Grid charge and there shall not be any rate of return for *SO.*

4.2.2 Energy Charge

The energy charge per kWh shall include variable costs relating to:

a. Physical *losses* of electricity incurred in the process of *transmission*.

b. Costs associated with the procurement of ancillary services, such as *regulation* of *frequency* and power – primary, secondary and tertiary, *regulation* of voltage, black start service,

4.3 Formula

The three charges, namely ICC charge, fixed charge (demand component) and variable charge (energy component), shall lead to a basic *postage stamp* for *transmission* services, expressed as follows:

Transmission tariff (TT) = Individual Cost Component (ICC) + *Use of System Charge* (UoSC),

Where;

UoSC = Capacity Charge (CC) + Energy Charge (EN)

Then;

$$TT_t = ICC_t + CC_t + EN_t \qquad (1)$$

Where; capacity charge is

$$CC_t = \frac{PD_t}{\sum PD_t} * (TFC_t + GSC_t)$$

And energy charge is

$$EN_t = \frac{EC_t}{\sum EC_t} * TVC_t$$

If;

$$TT_t = ICC_t + CC_t + EN_t$$

Then;

$$TT_t = ICC_t + \frac{PD_t}{\sum PD_t} * (TFC_t + GSC_t) + \frac{EC_t}{\sum EC_t} * TVC_t \qquad (2)$$

With:

- TT_t: *Transmission* Tariff in period t. This is the *transmission* tariff to be paid by a *customer* of the *TNSP* in the current *month*;

- ICC_t: Individual Cost Component. These are costs incurred by *TNSP* in the current *month* specific to a *customer* or *customer* specific costs to be paid over a certain period of time on a monthly basis as may be determined;

- TFC_t: Total Fixed Costs in period t for *TNSP*. This is the Revenue Requirement for the *TNSP* as approved by the *ERB*. These total costs to be incurred by the *TNSP* in the *test year* shall be paid by the *customers* in equal monthly installments;

- GSC_t: Total Fixed Costs in period t for *SO*. This is the Revenue Requirement for the *SO* as approved by the *ERB*. These total costs to be incurred by the *SO* in the *test year* shall be paid by the *customers* in equal monthly installments;

- PD_t: Peak demand in period t, expressed in *kVA*. The maximum demand of a *customer's* installed capacity for the test year;

- $\sum PD_t$: Sum of Peak Demands in period t. This is the summation of all peak *customer* demands for the test year*.*

- TVC_t: Total Variable Cost in period t. This is the total cost of all variable costs like *losses*, congestion costs and other variable costs incurred by the *TNSP* in the current *month.*
- EC_t: Energy Component in period t, expressed in *kWh* or *kVAh* for *transmission*. The energy component is the energy a *customer* transmitted in the current period;

- $\sum EC_t$: Sum of Energy Components in period t. This is the total energy transmitted by all *customers* in the current *month*;

The *transmission* tariff as defined up to this stage does not give incentives for efficient use of the grid, siting of new generation or avoiding congestion.

4.4 Incentive for efficient dispatch and siting new generation or demand

The *SO* shall provide incentives for both dispatch of new investments in generation and for new demand nodes to be located at the places where they best support the overall system regarding congestion, *losses* (including those under peak conditions), voltage stability, reliability and safety. A certain *generator* may be at a point in the grid where its presence is essential to maintain voltage stability. Therefore, the value of that *generator* should be higher than that of a *generator* at a very stable node.

This incentive could start from a number of critical load flow analyses over a previous year, identifying e.g. congested lines or other problems in the grid. Using data from typical and critical load flows, the generation and demand nodes would be separately ordered by their function in reducing congestion, loss, stability and reliability for a defined level of quality. In nodes causing extra congestion or other problems, a surplus (a premium) charge could be added to the overall *postage stamp*, relative to the deviation from the average. In nodes where extra generation or demand leads to fewer problems in the grid, the *postage stamp* rate could be reduced (a discount). The premium and discount would be calculated in such a way that their combined effect for the *SO* is zero. The *transmission* tariff becomes:

$$TT_t = ICC_{t-1} + \frac{PD_t}{\sum PD_t} * (TFC_t + GSC_t) + \frac{EC_t}{\sum EC_t} * TVC_t + GQC_t \qquad (3)$$

with

- GQC_t: Grid Quality Charge, either positive or negative, where $\sum GQC_{t-1} = 0$.

This node dependent Grid Quality Charge would be calculated and published for each node of the grid. The load flow study should be repeated after each major modification of the grid, and at least once a year. Because the basis for the surplus is time dependent (on and off peak, general load situation due to *day* of the week and/or season), this charge should also be time dependent.

For particular investments, the parties involved may require the *SO* to make a confidential study of the precise effect for their intended investment at the potential nodes.

The node-dependent premium or discount leads to preferential dispatching of those plants to reduce congestion and *losses* and improve network stability. In this way, they encourage efficient use of the existing network. They are also a long-term incentive for citing new generation or demand.

5 International wheeling charges

SAPP wheeling charges for transit electricity shall apply.

PART 7 - INFORMATION EXCHANGE CODE

1 Objective

The objective of the *information* exchange code is to define the obligations of *parties* with regard to the provision of *information* for the implementation of the *ZGC* in order to ensure the non-discriminatory access to the *Transmission System (TS)* and the safe, reliable provision of *transmission* services.

2 Scope

Information requirements shall cover planning *information*, operational *information* and post-dispatch *information*.

The *service-providers*, the *Energy Regulation Board* (*ERB*) and *customers* shall define the *information* requirements.

3 Precedence

In the event of inconsistencies between any part of the *ZGC* and the *Information* Exchange Code, with respect to *information* exchange, the provisions of the *Information* Exchange Code shall prevail.

4 ***Information*** exchange interface

For each type of *information* exchange, *parties* shall provide at the least the following *information*:

a. The name and contact details of the person(s) designated by the *information owner* to be responsible for provision of the *information*.

b. The names and contact details of and the *parties* represented by persons requesting the *information*.

c. The purpose for which the *information* is required.

The *parties* shall agree on appropriate confirmation procedures for the transfer of *information.*

5 System planning ***information***

5.1 Objective

a. To provide interaction of *end-use customers'* planned system with the *TS*

b. To provide *information* for the *TS* to supply *end-use-customers* for system planning and development

c. To facilitate existing and planned connections

d. To provide fault condition *information*

5.2 *Information* required by *TNSPs*

Customers may be required by a *TNSP* to provide *information* for either, but not limited to, the following reasons:

a. To plan and develop the *TS*,

b. To monitor current and future power system adequacy and performance, or

c. To fulfil its statutory or regulatory obligations.

Customers shall provide such *information,* without unreasonable delay, as the *TNSP may* request on a regular basis.

Customers shall submit to the *TNSP* the *information* listed in the Appendices as follows:

i. Appendix 2 – *information* from *distributors* or *end-use-customers*

ii. Appendix 3 and 4 – *information* from *generators*

Customers shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *TNSP* with *information* as outlined in appendix 11.

The *TNSP* may estimate any system planning *information* not provided by a *customer* as specified in Appendix 3 or 4. The *TNSP* shall take reasonable steps to reach agreement with the *customer* on estimated *data* items. The *TNSP* shall indicate to the *customer* all such estimated *data* items. The obligation to ensure the accuracy of the *data* remains with the *customer*.

Generators shall submit weekly updates to the relevant *TNSP* and *SO* all the maintenance planning *information* detailed in Appendix 4 with regard to each *unit* at each *power station*.

5.3 *Information* required by *Customers*

The *TNSP* shall provide *customers* or potential *customers*, upon request, with any relevant *information* that they require to properly plan and design their own networks/installations or comply with their obligations in terms of the ZGC.

The *TNSP* shall make available all the relevant *information* related to network planning as described in the Network Code.

5.4 *Information* required by *Generators*

The *TNSP* shall provide the *generators* with *information* about equipment and systems installed in the *HV yards* defined in Appendix 10.

The *TNSP* shall provide the *generators* with monthly rolling maintenance schedule for all planned work in *HV* yards for a period of one year in advance.

Log books on all vessels under pressure for receivers installed in *HV* yards shall be made available on request from the *generator*.

5.5 *Information* required by the *SO*

Customers shall provide the *SO* with updated technical *data* required for studying the behaviour of the *IPS*.

6 Operational *information*

6.1 Pre-commissioning studies

Customers shall meet all system planning *information* requirements before the commissioning test date, such as confirming any estimated values assumed for planning purposes or, where practicable, replacing them with validated actual values and with updated estimates for the future.

The *SO* shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified plant. Such studies shall utilise *data* supplied by *customers* in accordance with section 5 of this Code, to verify that all control systems are correctly tuned and planning criteria have been satisfied.

The *SO* may request adjustments prior to commissioning should tuning adjustments be found to be necessary. The asset owner shall ensure that all system planning *information* records are maintained for reference for the operational life of the plant. *Information* shall be made available within reasonable time on request from the *SO*.

6.2 General *information* requirements

All measurements and indications to be supplied by *participants* to the *SO* shall be presented in such form as may be prescribed by the *SO*. These shall include, but not be limited to, the standards defined in Appendix 5.

Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the *information*, such a *participant* shall report to the *SO* and restore or correct the signals and/or indications as soon as practical.

Following a modification to the *TS*, additional measurements and/or indications in relation to a *participant's* plant and equipment may be needed to meet *TS* requirements. In such an instance the *SO* shall notify the affected *participants*. The costs related to such modifications shall be on account of the *participant* effecting the modification.

On receipt of such notification from the *SO* the *participant* shall promptly ensure that such measurements and/or indications are made available at the *RTU*.

The *data* formats to be used and the fields of *information* to be supplied to the *SO* by the various *participants* shall be as defined in Appendix 5 of this code.

The *TNSP* shall provide feedback to *customers* regarding the status of equipment and systems installed in the *substations* where they are connected to the *TS* upon request. Agreements between *parties* shall determine the details and *frequency* of such feedback.

Plant status reports provided by the *TNSP* will also include contingency plans where applicable.

In the network where out – of – step relays are installed, the *SO* shall inform *customers* how the relays are expected to operate. The characteristics of such an islanded network shall be provided, based on the most probable local network configuration at such a time.

6.3 Commissioning and notification

All *Participants* shall ensure that exciter, turbine governor and *FACTS* control system settings are implemented and are as finally recorded by the *SO* prior to commissioning.

Participants shall give the *SO* reasonable advance notice, as defined in the System Operation Code, of the time at which the commissioning tests will be carried out. The *SO* and the *participant* shall agree on the timeous provision of operational *data* as per Appendix 5.

Participants shall jointly notify the *SO* about the results of the verification of all measurements and/or indications for functionality and accuracy once every five (5) years, so as to achieve overall accuracy of operational measurements within the limits agreed.

Commissioning records shall be maintained for reference by the *SO* for the operational life of the plant and shall be made available, within a reasonable time, to any *participants* upon request.

The asset owner shall communicate changes made to commissioned equipment, during an *outage*, to the *SO* and the relevant *TNSP*, before the equipment is returned to service. The *TNSP* shall keep commissioning records of operational *data* as per Appendix 5, for the operational life of the plant connected to the *TS*.

6.4 Inter *control centre* communication

This is communication between the *SO* and *customer control centres*. For normal and abnormal conditions, the following shall apply.

6.4.1 Normal Conditions

Upon request *control centres* shall provide each other with network *information* required for the *security*, safety, reliability and integrity of the *TS.* Such *information* exchange shall be electronic and/or paper-based within the time frame agreed upon by the *participants*.

The *participants* shall optimise redundant *control centre* facilities where required in order to ensure the *security* of the *TS* and its safe operation.

6.4.2 Abnormal Conditions:

In abnormal conditions, communication shall be limited to the level necessary to enable the *SO* return the *IPS* to its normal condition. All *control centres* will therefore be required to await operational instructions from the *SO*, except in situations where that *participant* is islanded, in which case he would assume control of its own *frequency* and voltage, and await synchronising instructions from the *SO*. In exceptional situations, when a *customer*'s network needs support from the *IPS*, they shall communicate the network status, and the kind of support needed.

6.5 Communication facilities requirements

The communication facilities for voice and data that are to be installed and maintained between the *SO* and *participants* shall comply with the applicable *IEC* standards for *SCADA* and communications equipment.

6.5.1 Telecontrol

The *information* exchange shall support *data* acquisition from *RTU*s, *SCS* and *PCS*. The *SO* shall monitor the state of the *IPS* via telemetry from the *RTU* connected to the *participants'* plant.

The signals and indications required by the *SO* are defined in Appendix 5, together with such other *information* as the *SO* may from time to time reasonably require by notice to the *participant*.

Participants shall interface via the standard digital interfaces, as specified by the *SO*. Interface cabinets shall be installed in the *participants*' plant and equipment room if required. The provision and maintenance of the wiring and signalling from the *participants*' plant and equipment to the interface cable shall be the responsibility of the *participant*.

The capability for the *SO* to deactivate and reactivate the scanning of a given *RTU* shall be provided by the *participants*, as shall the capability of monitoring the availability of all *RTU* centrally.

Participants shall comply with such telecontrol requirements as may be applicable to the primary *control centre* and, as reasonably required, to the *emergency control centre* of the *SO*.

6.5.2 Telephone/facsimile

Each *customer* shall be responsible for the provision and maintenance of at least one telephone and one facsimile unit and these shall be reserved for operational purposes only. These facilities shall be continuously attended to and answered without undue delay.

The *SO* shall use a voice recorder for historical recording of all operational voice communication with *participants*. These records shall be available for at least three (3) *months* after which it will be disposed off. The *SO* shall make the voice records of an identified incident in dispute available within a reasonable time period after such a request from a *participant* and/or the *ERB*.

6.5.3 Electronic mail

The *participants* shall provide each other with electronic mailing addresses of contact persons as defined in this Code.

6.6 *SCADA* and communication infrastructure at *points of supply*

6.6.1 Access and security

The *SO* shall agree with *participants* the procedures governing security and access to the *participants*' *SCADA*, computer and other communication equipment. The procedures shall allow for adequate access to the equipment and *information* by the *SO* or its nominated representative for purposes of maintenance, repair, testing and the taking of readings.

Each *participant* shall designate a person with delegated authority to perform the duties of *information owner* in respect of the granting of access to *information* covered in this code to third parties, and shall disclose that person's name and contact details to the *ERB*. Each *participant* may, at its sole discretion, designate more than one person to perform these duties.

6.6.2 Time standards

All *information* exchange shall be *GPS* satellite time signal referenced. The *SO* shall ensure broadcasting of the standard time to relevant telecommunication devices in order to maintain time coherence.

6.6.3 Integrity of installation

The *participant* shall be responsible for optimising the reliability and *security* of the facilities to comply with the *SO* equipment and *OEM* minimum requirements. This includes the provision, at no charge to the *SO*, of an uninterruptible power supply with an eight-hour standby capacity.

6.7 *Data* storage and archiving

The obligation for data storage and archiving shall lie with the *information owner*.

The systems must provide for clear and accessible audit trails on all relevant operational transactions. All requests that require an audit on a system shall be undertaken with reasonable notice to the *parties*.

The *information owner* shall keep all *information* for a period of at least five (5) years, unless otherwise specified in the *ZGC*, commencing from the date the *information* was created.

The *parties* shall ensure security against unauthorised access, use and loss of *information*.

Parties shall store planning *information* that is kept electronically for at least five (5) years or for the life of the plant or equipment concerned, whichever is longer.

The *SO* shall store operational *information* in a historical repository sized for 3 years *data*. The *data* includes:

a. *TS* time-tagged status *information*, change of status alarms and event messages

b. Hourly *scheduling* and accounting *information*

c. Operator logs and operations

An audit trail of all changes made to archive *data* should be maintained. This audit trail shall identify all changes made, and the time and date of the change. The audit trail shall include both before and after values of all content and structure changes.

7 Post-dispatch *information*

7.1 System *information*

The *SO* shall provide *participants*, with at least the following system *information*:

a. Hourly system total *MW* loading

b. Hourly price and average daily price per *kWh*

c. Hourly individual power station *MW* sent out

d. Hourly system constraints and *constrained generation*

e. Hourly international tie-line power flow

f. System load flow *data*

7.2 Generation *information* settlement

Participants shall meet at least every three *months* to reconcile generation *information.* Should this *information* be classified as confidential, both parties shall treat it accordingly.

7.3 Additional post dispatch *information*

The *SO* shall provide operational *information* regarding station dispatch and overall dispatch performance as specified in Appendix 7.

7.4 Half-hourly demand *metering data*

The *TNSP* shall provide *participants* with half-hourly metered *data* pertaining to their installations.

8 File transfers

The format of the files used for *data* transfer shall be agreed and defined by the supplier and receiver of the *information*.

The *parties* shall keep the agreed number of files for backup purposes so as to enable the recovery of *information* in the case of communication failures.

File	Description	Trigger Event	*Frequency*
AGC pulses	The total pulses sent to a *unit* by the *AGC* system to move the set-point up or down	Ongoing, file created at end of hour	Hourly
NERC	A list of the total *NERC "A1" and "A2" criteria* violations in the system over an hour	Ongoing, file appended at end of hour	Daily
System near real-time data	Historic near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Unit near real-time data	Historic near real-time unit data files on readings as required for post dispatch	Communication failure	To be agreed

9 Performance data

9.1 *Generator* performance data

Generators shall provide the *SO* with monthly-agreed performance indicators in relation to each *unit* at each *power station* as detailed in Appendix 8.

Generators shall report significant events, such as catastrophic failures, to *ERB* within seven (7) days of occurrence of such an event.

9.2 *Distributor* and *end-use customers* performance

The performance measurement of all *distributors* and *end-use customers* shall be in accordance with Zambian Standard ZS387, Electricity Supply – Power Quality and Reliability.

Distributors shall report periodic testing of under-*frequency* load shedding relays in the format given in appendix 12.

9.3 *TNSP* and *SO* performance

The *TNSP and SO* shall make available performance indicators, listed in appendix 13, monthly to the *ERB* and, *customers*.

The *TNSP* shall provide to *customers* all performance indicators at each point *of supply* in accordance with Network Code.

9.4 System operation performance *information*

The *SO* shall make at least the following IPS operational *information* available to all *participants*.

9.4.1 Daily:

a. The hourly actual demands of the previous day (*MW*)

b. The reserve amounts over the morning, midday and evening peaks of the previous day (*MW*)

9.4.2 Monthly:

a. *MW* generated, Imports, Exports, available for distribution/sale and *transmission losses*

b. Generation Plant Availability

c. *Regulating reserve* hours deficit over total hours

d. Number of *frequency* excursions

e. Report for each abnormal network condition and the action taken by the *SO* to restore normal operations

f. Network constraints as reported by the *TNSP*.

g. External Reliability Loss Factor (ERLF)

9.4.3 Annually:

a. Annual peak (*MW*), date and hour

b. Annual minimum (*MW*), date and hour

c. External Reliability Loss Factor (ERLF)

Following a *TS* disturbance, the *TNSP* shall make available all *information* collected via recorders installed at *substations*, to the *SO* for analyses within seven (7) days of the date of the occurrence. Thereafter the *SO* shall compile a report that shall be available to affected *customers* on request.

10. Confidentiality of *information*

Information exchanged between *parties* governed by this code shall be confidential, unless otherwise stated.

Confidential *information* shall not be transferred to a third *party* without the written consent of the *information owner*. *Parties* shall observe the proprietary rights of third parties for the purposes of this code. Access to confidential information within the Organisations of *Parties* shall be provided as reasonably required.

Parties receiving *information* shall use the *information* only for the purpose for which it was supplied.

The *information owner* may request the receiver of *information* to enter into a confidentiality agreement before confidential *information* is provided. A pro forma agreement is included in Appendix 1 of this code.

The *parties* shall take all reasonable measures to control unauthorised access to *information* and to ensure secure *information* exchange. *Parties* shall report any leak of the *information* that is governed by a confidentiality agreement, as soon as practicable after it becomes aware to the leak, and shall provide the *information owner* with all reasonable assistance to ensure its recovery or destruction, as deemed appropriate by the *information owner*.

APPENDIX 1: *Information* confidentiality

CONFIDENTIALITY AGREEMENT FOR *INFORMATION* TRANSFER TO THIRD *PARTIES*

CONFIDENTIALITY AGREEMENT

BETWEEN

…………………………………
(HEREINAFTER REFERRED TO AS THE *INFORMATION OWNER*)

AND

……………………………………………………………………………………….
(HEREINAFTER REFERRED TO AS THE RECIPIENT)

IN RESPECT OF INFORMATION SUPPLIED TO PERFORM THE FOLLOWING WORK:
………………………………………………………………………………………………
…………………………………………………………………………………
(HEREINAFTER REFERRED TO AS THE WORK)
ON BEHALF OF
……………………………………………………………………………………….
(HEREINAFTER REFERRED TO AS THE CLIENT).

1. The Recipient agrees to treat all *information* (hereinafter referred to as the Information) received from the *Information Owner*, whether in hard copy or electronic format or in any format whatsoever, as strictly confidential.

2. The Recipient agrees to disclose the *Information* only to authorized persons who are in his permanent employ, and who require access to the *Information* to perform their duties in respect of the Work on behalf of the Client.

3. Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, shall enter into separate Confidentiality Agreements with the *Information Owner* prior to receiving the *Information*.

4. The Recipient undertakes to use the *Information* only to perform the Work on behalf of the Client, and for no other purpose whatsoever.

5. On completion of the Work, the Recipient shall at his expense return to the *Information Owner* all hard copy material and electronic media containing the *Information* supplied to him by the *Information Owner*. The Recipient shall

furthermore ensure that all duplicate copies of the *Information* in his or his employees' possession (electronic as well as hard copy format) are destroyed.

6. The Recipient shall take all reasonable measures to protect the security and integrity of the *Information*.

7. If requested to do so by the *Information Owner*, the Recipient shall forthwith at his expense return to the *Information Owner* all hard copy material and electronic media containing the *Information* supplied to him by the *Information Owner*. The Recipient shall furthermore ensure that all duplicate copies of the *Information* in his or his employees' possession (electronic as well as hard copy format) are destroyed.

8. The Recipient shall report any leak of the *Information*, howsoever caused, to the *Information Owner* as soon as practicable after he becomes aware of the leak, and shall provide to the *Information Owner* with all reasonable assistance to ensure its recovery or destruction (as deemed appropriate by the *Information Owner*).

Signed at ……………………………………………… on this the ………… *day* of

……………………………. by (full name) …………………………………….in his/her

capacity as ………………………………………. on behalf of

………………………………………, *the Information Owner*

……………………………………

Signed at ……………………………………………… on this the ………… *day* of

……………………………. by (full name) …………………………………….in his/her

capacity as ………………………………………. on behalf of

………………………………………, the Recipient

APPENDIX 2: *Distributor* and *end-use customer* data

Unless otherwise indicated, the following *information* shall be supplied to the *TNSP*, prior to connection and then updated as and when changes occur.

a) Demand *data*

Connection capacity	Connection capacity required (*MW*)
Measured and forecast *data* (annually)	For each point of supply, the *information* required is as follows: A 5 and 15-year demand forecast. (See Appendix 9). A description setting out the basis for the forecast. The season of peak demand Quantification of the estimated impact of embedded generation where applicable. (See Appendix 9)
User network *data*	Electrical single-line diagram of user network to a level of detail to be agreed with the *service- providers*, including the electrical characteristics of circuits and equipment (R_1, X_1, B_1, R_0, X_0, B_0, continuous and probabilistic ratings). Contribution from *customer* network to a three-phase short circuit at *point of connection* (including that from *embedded generation* if available). Connection details of all *customer* transformers, shunt capacitors, shunt reactors etc. connected to the secondary voltage levels of the *customer* connected the *TS*. (the requirement here is for data pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVCs, etc. to the *point of supply* for purposes of conducting harmonic resonance studies.) Electrical characteristics of all circuits and equipment at a voltage lower than secondary voltage levels of the *customer* connected the *TS* that may form a closed tie between two connection points on the *TS*.
Standby supply *data* (annually)	The following *information* is required from each *distributor* and *end-use customer* that can take supply from more than one supply point: Source of standby supply (alternative supply point(s)) Standby capacity required (*MW*)
General *information*	For each new connection from a *distributor* or *end-use customer*, the following *information* is required: Number and type of switch-bays required Load build-up curve (in the case of new end-user plant) Supply date (start of load build-up) Temporary construction supply requirements Load type (e.g. arc furnaces, rectifiers, rolling mills,

	residential, commercial, etc.) Annual load factor Power factor (including details of harmonic filters and power factor correction capacitors) Special requirements (e.g. QOS) Other *information* reasonably required by the *service-providers* to provide the *customer* with an appropriate supply (e.g. pollution emission levels for insulation design)
Disturbing loads	Description of any load on the power system that could adversely affect the *SO* target conditions for power quality and the variation in the power quality that can be expected at the point connected to the *TS*. (The areas of concern here are, firstly, motors with starting currents referred back to the nominal voltage at the *point of supply* exceeding 5% of the fault level at the *point of supply* and secondly, arc furnaces likely to produce *flicker* levels at the *point of supply* in excess of the limits specified in ZS387 Electricity Supply – Power Quality and Reliability standard. The size limit for arc furnaces is subject to local conditions in respect of fault level at the *point of supply* and background *flicker* produced by other arc furnaces and other equipment that will produce harmonics and/or negative and zero sequence current components, such as large *AC/DC* rectification installations.)

(b) *Transmission system* connected transformer *data*

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		A
Transformer rating		MVA_{Trans}
Transformer tertiary rating		MVA
Transformer nominal *LV* voltage		kV
Transformer nominal tertiary voltage		kV
Transformer nominal *HV* voltage		kV
Tapped winding		HV/MV/LV/None[2]
Transformer ratio at all transformer taps		
Transformer Impedance (resistance R and reactance X) at all taps	R+jX	% on rating MVA_{Trans}
For three-winding transformers, where there are external connections to all three windings, the impedance (resistance R and reactance X) between each pair of windings is required, measured with the third set of terminals open-circuit.	$Z_{HV/MV}$, $Z_{HV/LV}$, & $Z_{MV/LV}$	% on rating MVA_{Trans} % on rating MVA_{Trans} % on rating MVA_{Trans}
Transformer zero sequence impedances at nominal tap		
Zero phase sequence impedance measured between the *HV* terminals (shorted) and the neutral terminal, with the *LV* terminals open-circuit.	$Z_{HT\,0}$	Ohm
Zero phase sequence impedance measured between the shorted *HV* terminals and the neutral terminal, with the *LV* terminals short-circuited to the neutral.	$Z_{HL\,0}$	Ohm
Zero phase sequence impedance measured between the *LV* terminals (shorted) and the neutral terminal, with the *HV* terminals open-circuit.	$Z_{LT\,0}$	Ohm
Zero phase sequence impedance measured between the *LV* terminals (shorted) and the neutral terminal, with the *HV* terminals short-circuited to the neutral.	$Z_{LH\,0}$	Ohm
Zero phase sequence leakage impedance measured between the HV terminals (shorted) and the *LV* terminals (shorted), with the Delta winding closed.	$Z_{L\,0}$	Ohm
Earthing arrangement, including *LV* neutral earthing resistance and reactance core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

[2] Delete what is not applicable

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on request.

(c) Shunt capacitor or reactor *data* requirements

For each shunt capacitor or reactor or power factor correction equipment or harmonic filters with a rating in excess of 10MVAr connected to or capable of being connected to a *customer* network, the *customer* shall inform and provide the *TNSP* with the specific shunt capacitor or reactor *data* as well as network details necessary to perform primarily harmonic resonance studies. The *customer* shall inform the *TNSP* of his intention to extend or modify this equipment.

If any *participant* finds that a capacitor bank of 10MVAr or less is likely to cause harmonic resonance problems on the *TS*, he shall inform the *TNSP*. The 10MVAr minimum size limit shall thereafter be waived in respect of the affected network for *information* reporting purposes in respect of this code, and the *TNSP* shall inform the affected *participants* of this fact and request the additional *data*. If the affected network is modified or reinforced to the extent that capacitor banks of 10MVAr or less no longer cause harmonic resonance problems on the *TS*, the *TNSP* shall inform the affected *participants* that *information* reporting requirements have returned to normal.

Any *party* to this code investigating a complaint about harmonic distortion, shall have the right to request such additional information (including, but not restricted to, *data* from harmonic distortion measuring devices) from *parties* in the vicinity of the source of the complaint as may reasonably be required to complete the investigation.

Shunt capacitor or reactor rating	Rating (MVAr)
Reactor/capacitor/harmonic filter[3]	
Location (station name)	
Voltage rating	*kV*
Resistance/reactance/susceptance[2] of all components of the capacitor or reactor bank	
Fixed or switched	
If switched	Control details (manual, time, load, voltage, etc.)
If automatic control	Details of settings. If under FACTS device control (e.g. SVC), which device?

(d) Series capacitor or reactor *data* requirements

Series capacitors are installed in long *transmission* lines to increase load transfer capability.

[3] Delete what is not applicable

Series reactors are installed to limit fault levels, or to balance load sharing between circuits operated in parallel that would otherwise not share load equitably, or to balance load sharing on an interconnected network.

Reactor/capacitor[2]	
LOCATION (SPECIFY SUBSTATION BAY WHERE APPLICABLE)	
Voltage rating	kV
Impedance rating	Ohm or MVAr
Current rating (continuous and *emergency*, maximum times for *emergency* ratings)	Continuous: A Hours A Hours A Hours A

Note: if a series capacitor or reactor is located in a dedicated reactor or capacitor station (i.e. a *substation* built to hold only the series reactor or capacitor), the lines or cables linking it to each remote end substation must be specified as separate circuits under line or cable *data*.

(e) FACTS devices

(i) FACTS devices

FACTS devices enable system parameters (voltage, current, power flow) to be accurately controlled in real time. Because of their cost, they are generally used only if cheaper, more conventional, solutions cannot deliver the required functionality.

Applications requiring rapid control capability include the following:

a. Voltage *regulation* following loss of a system component, generation, large load.

b. Arc furnace voltage *flicker* mitigation.

c. Negative phase sequence voltage compensation

d. SSR damping.
e. Machine transient stability enhancement.

f. System load transfer capability enhancement.

g. Load sharing control in interconnected, deregulated, networks.

The most commonly used FACTS device is the SVC. Other FACTS devices made possible by advances in power electronics and control systems include STATCON, TCSC, thyristor controlled tap changer, thyristor controlled phase shifter, BES (Battery Energy Storage), and UPC. The common factor is rapid control capability.

Because FACTS devices are purpose-designed for their specific applications, the following data is required:

Name	Station, HV voltage, device number
Type	(SVC, STATCON, TCSC, etc.)
Configuration: Provide a single line diagram showing all *HV* components and their *MVA/MVAr* and voltage ratings, with all controlled components identified as such.	
Control system: Provide a block diagram of the control system suitable for dynamics modeling.	
Primary control mode	Voltage control, arc furnace *flicker* mitigation, negative phase sequence voltage control, etc.

Customers are required to perform, or cause to be performed, harmonic studies to ensure that their installation does not excite harmonic resonance, and that harmonic distortion levels at the *PCC* with the *TS* do not exceed the limits specified in ZS 387 Electricity Supply - Quality and Reliability standard.

(ii) HVDC

HVDC is a form of FACTS device because of the rapid control capabilities. However, HVDC is treated separately because its primary function is the *transmission* of real power.

HVDC is used to connect two systems that are not necessarily interconnected via the AC network (and thus in synchronism), or even at the same nominal *frequency*.

Customers wishing to connect HVDC systems to the *TS* shall supply a single line diagram showing all HV plant (including valve bridges) forming part of the HVDC system, plus additional HV plant required for its proper operation, e.g. harmonic filters, synchronous condensers, FACTS devices, etc. *Customers* and the *TNSP* shall cooperate in performing, or causing to be performed, studies to determine network-strengthening requirements needed to accommodate the HVDC system without violating the planning criteria specified in the Network Code. In addition, *customers* shall thereafter perform, or cause to be performed, studies to demonstrate that the proposed HVDC system does not exceed QOS parameters specified in ZS387 Electricity Supply – Power Quality and Reliability standard, and where applicable shall specify what additional HV plant will be required to ensure compliance with this standard.

(f) Information on *customer* networks

If a *customer* will have two or more points of supply from the *TS*, including the one applied for, the *customer* shall specify the amount of load to be transferred from existing points of supply to the new one under normal conditions as well as under contingencies. The same requirement applies to any *embedded generators* within the *customer's* network, since they affect fault levels as well as net load on the system.

The *customer* shall also specify whether he intends to interconnect two or more *transmission* points of supply via his network. In such circumstances the *customer* shall provide detailed information on the lines and cables used.

Where a circuit consists of two or more segments of different characteristics (different overhead line tower and/or conductor bundle types and/or underground cable types), each section shall be specified separately.

Overhead line *data*

	Units
Line description	Name ("from" busbar, "to" busbar, circuit number and, where applicable, line section number numbered from the "from" bus end)
Line voltage (specify separately for dual voltage multi-circuit lines)	kV
Single / double / multiple circuit	
Standard suspension tower *information* (to confirm impedance): Supply copy of tower drawing, or sketch drawing showing co-ordinates of shield wire and phase conductor bundle attachment points relative to tower centre line and ground level at nominal tower height.	
Phase sub-conductor type (per circuit)	
Number of sub-conductors per phase conductor bundle	
Sub-conductor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)	Mm
Number of earth wires	
Earthwire description	
Line length	Km
Conductor parameters (R, X, B, R_0, X_0, B_0)	Ohmic values or p.u. on 100MVA base (specify)
Conductor normal and *emergency* ratings	Ampere or 3 phase MVA at nominal voltage

Cable data

Cable description	Name ("from" busbar, "to" busbar, circuit number, and where applicable, line section number numbered from the "from" bus end)
Voltage rating	kV
Type (copper/aluminium)	(Delete what is not applicable)
Size	mm^2
Impedance (R, X, B, R_0, X_0, B_0)	Ohms or p.u. on 100MVA base (specify)
Length	Km

Continuous and (where applicable) *emergency* current rating and time limit	Amp or MVA at nominal voltage (specify), hours maximum at *emergency* rating

APPENDIX 3: *Generator* planning *data*

Unless otherwise indicated, the following *information* shall be provided to the *TNSP* and *SO*, prior to connection and then updated as and when changes occur.

(a) *Power station* data

Generator name (Owner)	
Power station name	
Number of *units*	
Primary fuel type / prime mover	For example gas, hydro, fossil or nuclear
Secondary fuel type	For example oil
Capacity requirement	Generation sent-out connection capacity required (MW)
Blackstart Capability	**CONTINGENCY PLANS TO RESTART THE GENERATORS' OWN SYSTEMS AFTER A TOTAL OR PARTIAL COLLAPSE IN THE NETWORK.**
Partial load rejection capability	A description of the amount of load the *unit* can automatically govern back, without any restrictions, as a function of the load at the point of *governing* initiation.

(b) *Unit* data

Unit number	
Capacity	*Unit* capacity (*MW*)

Normal maximum continuous generation capacity:	MW
Normal maximum continuous sent out capacity	MW
Unit auxiliary active load	MW
Unit auxiliary reactive load	MVAr
Maximum (EL1) generating capacity	MW
Maximum (EL2) sent out capacity	MW
Normal minimum continuous generating capacity	MW
Normal minimum continuous sent out capacity	MW
Generator rating (Mbase)	MVA
Normal maximum lagging power factor	MVAr
Normal maximum leading power factor	MVAr
Governor droop	
Forbidden loading zones	MW
Terminal voltage adjustment range	KV
Short circuit ratio	
Rated stator current	Amp
Time to synchronise with penstock charged (warm)	Hour
Time to synchronise with penstock empty from (cold)	Hour
Normal loading rate	MW/min
Normal de-loading rate	MW/min
Partial load rejection capability	% MW name plate rating

Description	Data
Capability chart showing full range of operating capability of the generator, including thermal and excitation limits	Diagram
Open circuit magnetisation curves	Graph
Short circuit characteristic	Graph
Zero power factor curve	Graph
V curves	Diagram

Documents	Description
Protection setting document	A document agreed and signed by the *SO* containing the following: - A section defining the base values and per unit values to be used - A single line diagram showing all the protection functions and sources of current and voltage signals - A protection tripping diagram(s) showing all the protection functions and associated tripping logic and tripping functions

	- A detailed description of setting calculation for each protection setting, discussion on protection function stability calculations, and detailed dial settings on the protection relay in order to achieve the required setting - A section containing a summary of all protection settings on a per unit basis - A section containing a summary for each of the protection relay dial settings/programming details - An annex containing plant *information* data (e.g. OEM data) on which the settings are based - An annex containing OEM *information* sheets or documents describing how the protection relays function
Excitation setting document	A document agreed and signed by the *SO* containing the following: - A section defining the base values and per unit values to be used - A single line diagram showing all the excitation system functions and all the related protection tripping functions - An excitation system transfer function block diagram in accordance with IEC standard models - A detailed description of setting calculation for each of the excitation system functions, discussion on function stability calculations, and detailed dial settings on the excitation system in order to achieve the required setting - A section containing a summery of all settings on a per unit basis - A section containing a summary for each of the excitation system dial settings/programming details. - An annex containing plant *information* data (e.g. OEM data) on which the settings are based - An annex containing OEM *information* sheets or documents describing the performance of the overall excitation system and each excitation function for which a setting is derived
Governor setting document	A document agreed and signed by the *SO* containing the following: - A section defining the base values and per unit values to be used - A single line diagram showing all the excitation system functions and all the related protection tripping functions - An excitation system transfer function block diagram in accordance with IEC standard models - A detailed description of setting calculation for each of the governor system functions, discussion on function stability calculations, and detailed dial settings on the

	governor system in order to achieve the required setting - A section containing a summery of all settings on a per unit basis - A section containing a summary for each of the governor system dial settings/programming details - An annex containing plant *information* data (e.g. OEM data) on which the settings are based - An annex containing OEM *information* sheets or documents describing the performance of the overall governor system and each governor function for which a setting is derived

(c) Reserve capability

The generator shall provide the *SO* with the reserve capability of each *power station*. The reserve capability shall be indicated as defined in the SAPP Operating Guidelines (1996)

(d) Unit parameters

	Symbol	Units
Direct axis synchronous reactance	X_d	% on rating
Direct axis transient reactance saturated	$X'_{d_{sat}}$	% on rating
Direct axis transient reactance unsaturated	$X'_{d_{unsat}}$	% on rating
Sub-transient reactance unsaturated	$X''_d = X''_q$	% on rating
Quad axis synchronous reactance	X_q	% on rating
Quad axis transient reactance unsaturated	$X'_{q_{unsat}}$	% on rating
Negative phase sequence synchronous reactance	X_2	% on rating
Zero phase sequence reactance	X_{0q}	% on rating
Turbine generator inertia constant for entire rotating mass	H	MW s/MVA
Stator resistance	Ra	% on rating
Stator leakage reactance	X_L	% on rating
Poiter reactance	X_P	% on rating
Generator time constants: - Direct axis open-circuit transient - Direct axis open-circuit sub-transient - Quad axis open-circuit transient - Quad axis open-circuit sub-transient - Direct axis short-circuit transient - Direct axis short-circuit sub-transient - Quad axis short-circuit transient - Quad axis short-circuit sub-transient	 Tdo' Tdo'' Tqo' Tqo'' Td' Td'' Tq' Tq''	 sec sec sec sec sec sec sec sec
Speed damping	D	
Saturation ratio at 1 pu terminal voltage	S(1.0)	
Saturation ratio at 1.2 pu terminal voltage	S(1.2)	

(e) Excitation system

The *generator* shall fill in the following parameters or supply a Laplace-domain control block diagram in accordance with IEEE or IEC standard excitation models (or as otherwise agreed with the *SO*) completely specifying all time constants and gains to fully explain the transfer function from the compensator or unit terminal voltage and field current to unit field voltage. *Customers* shall perform, or cause to be performed, small signal dynamic studies to ensure that the proposed excitation system and turbine governor do not cause dynamic instability. Where applicable, a PSS (power system stabiliser) shall be included in the excitation system to ensure proper tuning of the excitation system for stability purposes.

	Symbol	Units
Excitation system type (AC or DC)		Text
Excitation feeding arrangement (solid or shunt)		Text
Excitation system filter time constant	T_r	Sec
Excitation system lead time constant	T_c	Sec
Excitation system lag time constant	T_b	Sec
Excitation system controller gain	K_a	
Excitation system controller lag time constant	T_a	Sec
Excitation system maximum controller output	V_{max}	p.u.
Excitation system minimum controller output	V_{min}	p.u.
Excitation system *regulation* factor	K_c	
Excitation system rate feedback gain	K_f	
Excitation system rate feedback time constant	T_f	Sec

(f) Speed governor system, turbine and boiler models

The *generator* shall supply a Laplace domain control block diagram in accordance with IEC standard prime mover models for thermal and hydro *units* (or as otherwise agreed with the *TNSP*), fully specifying all time constants and gains to fully explain the transfer function for the governor, turbine, penstocks and control systems in relation to *frequency* deviations and set point operation.

(g) Control devices and protection relays

The *generator* should supply any additional Laplace domain control diagrams for any outstanding control devices (including power system stabilisers) or special protection relays in the unit that automatically impinge on its operating characteristics within 30 seconds following a system disturbance and that have a minimum time constant of at least 0,02 seconds.

(i) *Unit* step-up transformer

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		Amps
Transformer rating		MVA_{Trans}
Transformer nominal LV voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		
Transformer ratio at all transformer taps		
Transformer impedance at all taps (For three winding transformers the HV/LV1, HV/LV2 and LV1/LV2 impedances together with associated bases shall be provided)		% on rating MVA_{Trans}
Transformer zero sequence impedance at nominal tap	Z_0	Ohm
Earthing arrangement, including neutral earthing resistance and reactance		
Core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

(j) *Unit* forecast *data*

The *generator* shall provide the *TNSP* and *SO* with expected maintenance requirements, in weeks per annum, for each *unit* at a *power station*.

(l) Return to service of mothballed generating plant:

Once the *customer* has decided to return mothballed generating plant to service, the *TNSP* requires the *information* specified for new connections.

(m) Decommissioning of generating plant:

Decommissioning of plant is the permanent withdrawal from service of generating plant. The *TNSP* requires the following with a one-year notice period:

Generator name	
Power station name	
Unit number	
Date to be removed from commercial service	
Auxiliary supplies required for dismantling and demolition	kVA, point at which supply is require, duration

APPENDIX 4: Generator maintenance data

a) The 52-weeks-ahead *outage* plan per week per generator shall be updated weekly to the *SO* in the format shown below:

Annual Maintenance Schedule

Station Name:_______________________________

			Week							
Unit No.	Activity	MW lost	1	2	3	4	5…	…	n+51
1	Annual Maintenance	100							
2	Annual Maintenance	100							
2	Governor modernization	100							
3	Transformer oil	150							
ETC.									

b) The annual maintenance/*outage* plan per generator, looking 15 years ahead, shall also be supplied to the SO. The format shall be quarterly based as follows:

Five Year Ahead Maintenance Schedule

Station Name:__________________

			Years											
			1	2	3	4	5					15	15+1	15+n
Unit No.	Activity	MW lost												
1	Annual Maintenance													
2	Annual Maintenance													
2	Governor modernization													
3	Transformer oil													
etc														

c) A weekly variance report, explaining the differences between the planned and actual *outages*, shall be supplied to the SO as shown below:

	Outage	Start Date		End Date		Reason for difference
Unit No	Description	Plan	Actual	Plan	**ACTUAL**	

APPENDIX 5: Operational data

This appendix specifies the data format to be used by the SCADA system for the mapping of RTU data into the SCADA database. The database has a definition for each electrical configuration (ELC) or electrical object in the station. Each ELC definition specifies a different ELC type, e.g. transformers, units, feeders, etc, and is accompanied by a picture showing the ELC and all its associated devices as they would be indicated on the *SO* operational one-line displays. In each instance, the picture defines the primary devices and is followed by the points belonging to each device.

Description of table column headings used in this section

The headings in the tables of this section are described as follows:

(a) Device Gives the name of the device and acts as a collector of all point *information* belonging to the device.

Each binary status point can be mapped to one or two binary bits. In the case of a breaker or SOlator, the state is reported via two bits. In the case of single-bit alarm points, only one bit is used to report the state of the indication.

01_state This is the **alarm** state of the point.
10_state This is the **normal** state of the point.

In the table above the TYPE column indicates the number of bits used to report the state of the point in question.

For single-bit points please ignore the left-hand 0 or 1 value in the headings "01-State" and "10-State".

Where an indication uses two bits to report the state, the right-hand bit is used report that the state is OPEN and the left-hand bit to report the state when it is CLOSED. Thus an open condition will be "01" and a closed state will be "10".

It is thus illogical for a device to have a permanent value of either "00" or "11". However, if the device is in transit between "01" and "10" then a temporary value of "00" is possible. The SCADA system reports a state of "00" as "In transit", which will normally only be seen on slow-moving devices such as SOlators.

(b) Category defines the category the point belongs to: Health, Main Protection, Back-up Protection or *Information*.

Classical alarm systems attempt to set priorities on alarm points. However, the priority of a point changes as the system changes, which means having a fixed priority is not useful. As an alternative, the approach used here is to assign the point to the area that is affected by the indication. In this case we have four areas, namely:

Health	All alarm indications that refer to the health of the primary or secondary plant are assigned to this category.
Main Protection	All protection activity that is triggered by the Main 1 protection circuits is assigned to this category.
Backup Protection	Where back-up protection is installed, such as on transformers, or where Main 2 protection is used, these alarms are assigned to this category.
Information	Pure state change data such the state of a breaker or SOlator are assigned to this category. As such, no alarming is associated with these points – the data presented is pure *information*.

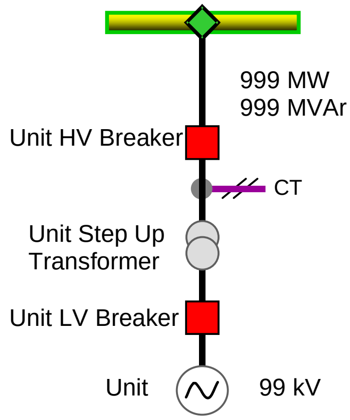
(c) Type Indicates the type of point – single-bit, double-bit, analogue or binary change detection.

(d) Control Indicates if there is a supervSOry control associated with the point

A5.1 Generator

The generator shall install operational measurements to specification from the SO so as to provide continuous operational *information* for both real time and recording purposes in relation to each *unit* at each *power station* in respect of the following:

(a) Gas turbines

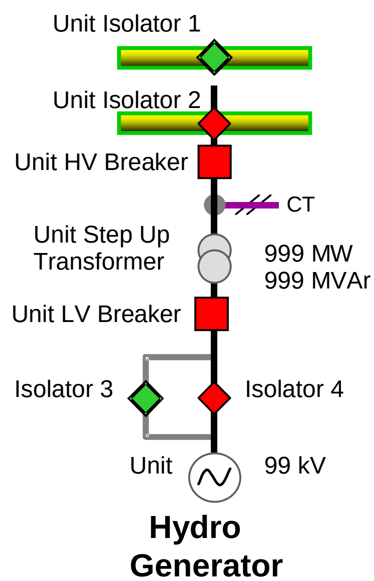


Gas Turbine

Unit isolator	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit isolator state	Open	Closed	Info	Double	False
Unit HV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
CT	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Unit Step Up Transformer	01_State	10_State	Category	Type	Control
Reactive power			Info	Analogue	False
Active power			Info	Analogue	False
Unit LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
Unit	01_State	10_State	Category	Type	Control

Engine A	Ready	Not ready	Health	Single	False
Engine B	Ready	Not ready	Health	Single	False
Frequency			Info	Analogue	False
Unit start not ready	Alarm	Normal	Health	Single	False
Remote control	On	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage			Info	Analogue	False
SupervSOry	SOlated	Off	Info	Single	False
Under-frequency start	Armed	Off	Health	Single	False
Unit at standstill	Yes	Normal	Info	Single	True
Unit auto load to base	Yes	No	Info	Single	True
Unit auto load to minimum	Yes	No	Info	Single	True
Unit auto load to peak	Yes	No	Info	Single	True
Unit failed to start	Alarm	Normal	Health	Single	False
Unit voltage			Info	Analogue	False
Unit in generation mode	Yes	No	Info	Single	True
Unit in SCO mode	Yes	No	Info	Single	True
Unit load rate	Fast	Slow	Info	Single	True
Unit loading mode	Auto	Manual	Info	Single	False
Unit reactive power generated			Info	Analogue	False
Unit reactive power sent out			Info	Analogue	False
Unit active power generated			Info	Analogue	False
Unit active power sent out			Info	Analogue	False
Unit tripped and locked out	Alarm	Normal	Info	Single	False
Unit under frequency start	Initiate	No	Info	Single	False

(b) Hydro units

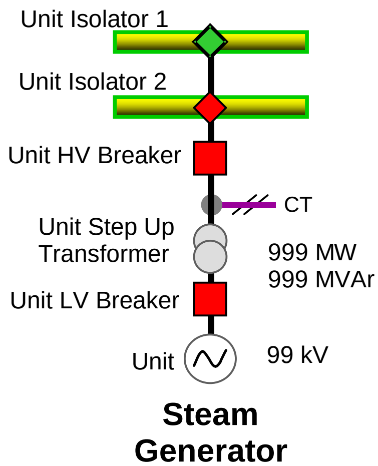


Unit SOlator 1	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
Unit SOlator 2	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
Unit HV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
CT	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Unit LV Breaker	01_State	10_State	Category	Type	Control

Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
Unit Step Up Transformer	01_State	10_State	Category	Type	Control
Reactive power			Info	Analogue	False
Active power			Info	Analogue	False
SOlator 3	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
SOlator 4	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
Unit	01_State	10_State	Category	Type	Control
Frequency			Info	Analogue	False
Auto load	Active	Normal	Info	Single	True
Automatic power factor regulator	Operated	Normal	Health	Single	True
Emergency trip	Operated	Normal	Main	Single	True
Unit start not ready	Alarm	Normal	Health	Single	False
Unit to pump mode	Active	Off	Info	Single	True
Unit to SCO mode	Active	Off	Info	Single	True
Pump start not ready	Alarm	Normal	Health	Single	False
Pump to generation mode	Active	Off	Info	Single	True
Pump to SCO mode	Active	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
SCO to generation mode	Active	Off	Info	Single	True
SCO to pump mode	Active	Normal	Info	Single	True
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage	Info	Analogue	Log_only	No	
Under-frequency start	Armed	Off	Health	Single	False
Unit AGC – high limit	High	Normal	Health	Single	False
Unit AGC – high regulating limit	Health	Analogue	Panel	No	
Unit AGC – low limit	Low	Normal	Health	Single	False
Unit AGC – low regulating limit			Health	Analogue	False
Unit AGC – raise/lower blocking	Off	Normal	Info	Single	False
Unit AGC – ramp rate			Info	Analogue	False

Unit AGC – set-point active power			Info	Analogue	True
Unit AGC – status	On	Off	Info	Single	False
Unit at standstill	Yes	Normal	Info	Single	True
Unit voltage			Info	Analogue	False
Unit guide vane			Info	Analogue	True
Unit in generation mode	Yes	No	Info	Single	True
Unit in pump mode	Yes	No	Info	Single	True
Unit in SCO mode	Yes	No	Info	Single	True
Unit load limiter			Info	Analogue	True
Unit reactive power generated			Info	Analogue	False
Unit reactive power sent out			Info	Analogue	False
Unit active power generated			Info	Analogue	False
Unit active power sent out			Info	Analogue	False
Unit synchronising	Yes	No	Info	Single	False
Unit turning in generation direction	Yes	No	Info	Single	False
Unit turning in motor direction	Yes	No	Info	Single	False

(c) Steam units



Unit SOlator 1	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
Unit SOlator 2	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Unit SOlator state	Open	Closed	Info	Double	False
Unit HV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
CT	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Unit Step Up Transformer	01_State	10_State	Category	Type	Control
Reactive power			Info	Analogue	False
Active power			Info	Analogue	False
Unit LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False

Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Unit breaker state	Closed	Tripped	Info	Double	False
Steam Unit	01_State	10_State	Category	Type	Control
Unit AGC – high limit	High	Normal	Health	Single	False
Unit AGC – high regulating limit			Health	Analogue	False
Unit AGC – low limit	Low	Normal	Health	Single	False
Unit AGC – low regulating limit			Health	Analogue	False
Unit AGC – raise/lower blocking	Off	Normal	Info	Single	False
Unit AGC – ramp rate			Info	Analogue	False
Unit AGC – set-point active power			Info	Analogue	True
Unit AGC – status	On	Off	Info	Single	False
Unit voltage			Info	Analogue	False
Unit islanded	Alarm	No	Health	Single	False
Unit reactive power generated			Info	Analogue	False
Unit reactive power sent out			Info	Analogue	False
Unit active power generated			Info	Analogue	False
Unit active power sent out			Info	Analogue	False

Generators contributing to *regulating reserve* shall provide indications for *emergency* generation and maximum generation for rescheduling.

A5.2 Distributor and end-use *customer*

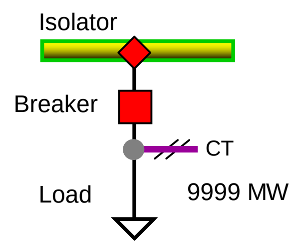
(a) *Transmission* equipment

The *Customer* shall provide operational *information* for both real time and recording purposes in relation to each feeder, transformer and compensation device at each *substation* required for the full functionality of a SVC, as well as full control by the SO.

(b) *Interruptible Load*

All *interruptible loads* shall meet the minimum requirements. The SO shall negotiate and integrate the conditions as presented in bilateral agreements and additional contracts without reducing the requirements as defined in this Grid Code.

The *interruptible load* shall install operational measurements to specification so as to provide operational *information* for both real time and recording purposes in relation to each controllable energy block in respect of the following minimum requirements for operation and control of a *interruptible load*:



Interruptible Load

Solator	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
SOlator state	Closed	Open	Info	Double	False
Breaker	01_State	10_State	Category	Type	Control
Unit breaker state	Closed	Tripped	Info	Double	True
CT	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Load	01_State	10_State	Category	Type	Control
Load reduction acknowledged	No	Yes	Info	Single	True
Load interrupt acknowledged	No	Yes	Info	Single	True
Block *load reduction* acknowledged	No	Yes	Info	Single	True
Return to service acknowledged	No	Yes	Info	Single	True
Load active power			Info	Analogue	False

APPENDIX 7: Post-dispatch *information*

The *SO* shall provide the following minimum operational *information* in near real-time and as historic data in relation to each *power station*:

No	Data description	Format	Size	Unit
1	High limit	Real	999,99	MW
2	Low limit	Real	999,99	MW
3	AGC mode CER/BLO	Character	3	
4	AGC status AUT/OFF/MAN	Character	3	
5	Set point	Real	99,99	MW
6	AGC pulse	Real	9,9	
7	Sent-out	Real	999,99	MW
8	Auxiliary	Real	999,99	MW
9	Contracted Power	Integer	999	MW
10	Station spinning	Integer	999	
11	32-bit flag on AGC settings	Integer		32 bits

The SO shall provide the following minimum operational *information* in near real-time in relation to the overall dispatch performance:

No	Data description	Format	Size	Unit
1	Area control error (ACE)	Real	999,99	MW
2	Average ACE previous hour	Real	999,99	MW
3	System *frequency* (Hz)	Real	99,999	MW
4	Frequency distribution current hour	Real	999,99	MW
5	Frequency distribution previous hour	Real	999,99	MW
6	System total generation	Integer	99999	MW
7	*Control area* total actual interchange	Integer	99999	MW
8	*Control area* total scheduled interchange	Integer	99999	MW
9	System operating reserve	Integer	99999	MW
10	System sent-out	Integer	99999	MW
11	System spinning reserve	Integer	99999	MW
12	AGC regulating up	Integer	99999	MW
13	AGC regulating down	Integer	99999	MW
14	AGC regulating up assist	Integer	99999	MW
15	AGC regulating down assist	Integer	99999	MW
16	AGC regulating up *emergency*	Integer	99999	MW
17	AGC regulating down *emergency*	Integer	99999	MW
18	AGC mode	Char	TLBC /CFC	
19	AGC status	Char	ON/ OFF	
20	Area control error output	Real	999.99	MW
21	System *transmission losses*	Real	999.99	MW
22	ZESA tie-lines	Integer	99999	MW
23	DRC tie-lines	Integer	99999	MW
24	BPC radial-line	Integer	99999	MW
25	AGC performance indicators			

APPENDIX 8: Generator performance data

Generator performance data is a means of providing a measurement of generating station processes. A combination of different metrics yields indicators that provide an objective assessment of critical parameters on the performance of key processes. They are used to identify non-performing areas in order to facilitate improvements. This is also used to provide industry with statistical data on how well the industry is performing.

The indicators will provide generating stations in Zambia an opportunity to benchmark their performance against other best run hydro *power stations* in the world. It also offers these station's management data for strategic management.

The Key Performance Indicators report on each station's efficiency and effectiveness is at a tactical level. The assumption here is that, even when a generating station is embedded in a vertically integrated utility, it is very possible to measure these statistics against a common benchmark.

For the purpose of these indicators, all generation equipment *outages* will be considered planned and scheduled at every beginning of the year. All other *outages* procured during the progression of the year will be considered unplanned.

a. Reliability

This indicator will be expressed in terms of Unit Capability Factor (UCF). The purpose of this indicator is to monitor progress in attaining high unit and plant energy production availability. It reflects the effectiveness of plant programmes and practices in maximizing available electrical generation and provides an overall indication of how well the plant was operated and maintained. It comprises Planned Capability Loss Factor (PCLF) and Unplanned Capability Loss Factor (UCLF) and it is expressed as a difference between 100% and the percentage attributed to PCLF and UCLF.

$$UCF = 100 - PCLF - UCLF$$

i. Unplanned capability loss factor (UCLF)

The purpose of this indicator is to monitor industry progress in minimising *outage* time and power reductions that result from unplanned equipment failures or other conditions. This indicator reflects the effectiveness of plant programmes and practices in maintaining systems available for safe electrical generation.

It is therefore an expression of energy lost due to *unplanned outages*, against the total available energy, calculated as a percentage.

$$UCLF = \frac{UnplannedMWhlost * 100\%}{TotalMWhdesigned}$$

ii. Planned capability loss factor (PCLF)

Planned capability loss factor is defined as the ratio of the planned energy *losses* during a given period of time to the reference energy generation expressed as a percentage.

Planned energy loss is energy that was not produced during the period because of planned shutdowns or *load reductions* due to causes under plant management control. Energy *losses* are considered to be planned if they are scheduled and appear on the System Yearly Maintenance Program. It will stimulate detailed scrutiny and predictability of generating plant so that *outages* are focused and scheduled one (1) year in advance.

$$PCLF = \frac{PlannedMWhlost * 100\%}{TotalMWhdesigned}$$

b. Internal Reliability Loss Factor

This factor is expressed to measure the number of internal factors leading to reduction in Reliability of generating plant against the total reduction in Reliability. It is therefore expressed as a percentage of energy lost due to internal faults leading to lost generation against available energy during the period.

$$IRLF = \frac{UnplannedMWhlostdueto\operatorname{int}ernalfaults * 100\%}{TotalMWhavailable}$$

c. External Reliability Loss Factor

This factor measures the influence that external factors leading to *forced outages* has on the generating plant. Such factors could include *transmission* line trippings/ *outages*, deferred maintenance activities due to system load changes, cascade trippings and many others. It is expressed as a percentage of energy *losses* due to faults external to the generating plant, leading to loss of generation against total available energy during the given period.

$$ERLF = \frac{UnplannedMWhlostduetoexternalfaults * 100\%}{TotalMWhAvailable}$$

d. Mean-Time-To-Repair (MTTR)

This factor measures the average time used to carry out repairs due to faults in any given period. It is expressed as the sum of all durations generating units were disconnected from the grid due to internal faults against the total number of breakdowns due to internal faults.

$$\frac{\sum_{n=1}^{n} t_n}{T} * 100\%$$

Where;

t = time duration for each internal fault

n = *outage* number

T is the total number of *outages* in the period.

e. Mean-Time-Between-Failures (MTBF)

This is expressed as the total time in a given period divided by the number of internal faults plus 1. It is meant to express on an average the time between any two failures following each other.

Mean-Time-To-Repair and Mean-Time-Between-Failures are two factors that are used to measure the quality of maintenance being carried out on generating plant.

f. Start-up Failure Rate (SFR)

This is expressed as the number of times a generating unit or plant fails to connect to the grid at the required time against the total number of requested synchronizations. This measure is used to gauge under-frequency recovery time.

$$SFR = \frac{NumberOffailedStartUps \times 100\%}{NumberOfContractedStartUps}$$

Start-up comprises the set of operations that enable the unit to be connected to the off-site power grid for the production of electrical energy according to requirements issued by the *SO*. It includes all the necessary “de-SOlations” and rendering to “normal” all equipment required for generation.

The contracted start-up refers to the number of start-up instructions issued and received from the *System Operation* by the Generation Control Room.

g. Total Unplanned Station Shutdowns (TUSS)

This is the total number of times that a generating station separates with the grid. It could either be as a result of an internal or external unplanned factor, but leading to a total station *outage*. It measures the protection requirements defined in the Network code, section 4.1, or it could be declared as an Ancillary Service as declared in the System Operations code section 7.

APPENDIX 9: Planning schedules

Schedule 1: Five and Fifteen-year demand forecast

	Demand = Total Demand + Distribution *Losses* – Embedded Generation					
		Energy	**Maximum demand**		**Expected minimum demand**	
Year		**GWh**	**MW**	**MVAr**	**MW**	**MVAr**
Measured (year 0)						
Year 1						
Year 2						
Year 3						
Year 4						
Year 5						
Year 6						
Year 7						
Year 8						
Year 9						
Year 10						
Year 11						
Year 12						
Year 13						
Year 14						
Year 15						

Schedule 2: Embedded generation > 50MVA

Generator	Tx *substation* name at closest connection point	Operating power factor	Installed capacity	Plant type	On-site usage		Net sent out		Generation net sent out contribution at peak									
			(MW)		Normal	Peak	Normal	Peak	Year 1	Year 2	Year 3	Year 4	Year 5	…	…	…	Year 14	Year 15

APPENDIX 10: Generator HV yard *information*

The *TNSP* shall provide the following *information* to *Generators* about equipment and systems installed in generator HV yards. The *TNSP* and the *SO* shall provide the stability criteria.

Equipment	Requirement
Circuit breaker	MCR rating, peak rating, operating time, OEM, installation date
CT and VT	CT and VT ratings, classes of equipment, burdening, OEM, installation date
Surge arrestor	OEM, age, installation date, number of operations
Protection	Description of protection philosophy for all protection schemes and functions installed, including ARC. Protection reliability *information* shall be available annually
Power consumption	List of power consumption requirement by equipment requiring supply from AC, DC and UPS
Link	MCR rating, peak rating, OEM, installation date
Outgoing Feeder	*MCR* rating, peak rating, erection date, length, impedance, transposition characteristics, thermal limits, installed protection, shielding.
Transformer	Transformer specifications for coupling transformers in HV yards. The records of coupling transformers in HV yards must be available on request.
Compressed air system	Compressed air system specifications including schematic drawings
Fault recorder	Fault recorder specifications including resolution, record time, triggering criteria, data format shall be provided on request. The *TNSP* shall review the fault levels and impedance to network center from HV yard annually.

Appendix 11: *Information* requirements for upgrading of existing connections and new connections.

Commissioning	Projected or target commissioning test date
Operating	Target operational or on-line date
Reliability of connection requested	Number of connecting circuits e.g. one or two feeders, or firm/non-*firm supply* required (subject to Network and Tariff Code requirements)
Location map.	Upgrades: Name of existing *point of supply* to be upgraded and supply voltage. New connections: Provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, specify the co-ordinates of the *point of connection*.
Site plan	Provide a plan of the site (with at least 1:200 or 1:500) of the proposed facility, with the proposed *point of supply*, and where applicable, the *transmission* line route from the facility boundary to the *point of supply*, clearly marked.
Electrical single-line diagram	Provide an electrical single-line diagram, drawn to the relevant *IEC standard*, of the *customer* intake *substation*.

Appendix 12: Reporting format for periodic testing of under-frequency load shedding relays.

Distributor: **Date:** ***Substation*:** **Fed from *transmission substation* (directly or indirectly):**				
	Activating frequency		Timer setting	
	Required	As tested	Required	As tested
Stage 1	48.8Hz		Instantaneous	
Stage 2	48.5Hz		Instantaneous	
Stage 3	48.2Hz		Instantaneous	
Stage 4	49.0Hz		20 seconds	
Stage 5	0.8Hz/s		Instantaneous	
	Feeders selected (Required)		Feeders selected (As tested)	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

(Current *SAPP* Guidelines)

Appendix13: Performance Indicators for *TNSPs and SO.*

Indicator	***Month***	**Year to date**	**12 MMI**	**Unit**
System minutes lost				Minutes
No. of Interruptions				
No. of statutory voltage transgressions				
Mandatory under-*frequency* load shedding				
Customer voluntary load shedding				
TS losses				%